I. Meeting Packet

State of Florida
Public Service Commission
INTERNAL AFFAIRS AGENDA
Thursday, October 24, 2013
Immediately following Commission Conference
Room 105 - Gerald L. Gunter Building

1. Draft Status Update to the Federal Communications Commission (FCC) Regarding the Limited Waiver of 47 C.F.R. §54.407(d), 47 C.F.R. §54.410(b)(2)(ii), 47 C.F.R. §54.410(c)(2)(ii), and 47 C.F.R. §54.410(e) for the State of Florida, and Petition to FCC for Permanent Waiver of FCC Rules 47 C.F.R. §54.407(d), 47 C.F.R. §54.410(b)(2)(ii), 47 C.F.R. §54.410(c)(2)(ii), and 47 C.F.R. §54.410(e). Approval is sought. (Attachment 1)

2. Staff's Review of the 2013 Ten-Year Site Plan. Approval is sought. (Attachment 2)

3. Legislative Update. (No Attachment)

4. Executive Director's Report. (No Attachment)

5. Other Matters. (No Attachment)

BB/mj

Attachment 1

State of Florida

Public Service Commission

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

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

DATE: October 15, 2013

TO: Braulio L. Baez, Executive Director

FROM: Robert J. Casey, Public Utilities Supervisor, Office of Telecommunications RC
Adam J. Teitzman, Attorney Supervisor, Office of the General Counsel AT BLB

RE: Draft Status Update to the Federal Communications Commission (FCC) Regarding the Limited Waiver of 47 C.F.R. §54.407(d), 47 C.F.R. §54.410(b)(2)(ii), 47 C.F.R. §54.410(c)(2)(ii), and 47 C.F.R. §54.410(e) for the State of Florida
and
Petition to FCC for Permanent Waiver of FCC Rules 47 C.F.R. §54.407(d), 47 C.F.R. §54.410(b)(2)(ii), 47 C.F.R. §54.410(c)(2)(ii), and 47 C.F.R. §54.410(e).
CRITICAL INFORMATION: Please place on the October 24, 2013 Internal Affairs. **COMMISSION APPROVAL OF STATUS UPDATE AND DRAFT PETITION IS SOUGHT**

On February 6, 2012, the FCC released a Report and Order and Further Notice of Proposed Rulemaking (Order) regarding Lifeline and Link Up Reform and Modernization (Order FCC 12-11 in Docket No. 11-42). The Order states that eligible telecommunications carriers (ETCs) must not seek reimbursement from the federal universal service fund unless the ETC has received from the state Lifeline administrator or other state agency, a copy of the Lifeline subscriber's application form.[1] The Order also requires state Lifeline administrators or other state agencies that are responsible for the initial determination of a subscriber's eligibility for Lifeline to provide each ETC with a hard-copy of each of the Lifeline application forms.[2] **COMMISSION APPROVAL OF THE DRAFT STATUS UPDATE AND PERMANENT WAIVER PETITION IS SOUGHT.**

The Order made the provision of the hard-copy Lifeline application requirement effective June 1, 2012. The United States Telecom Association (US Telecom) filed for and received three consecutive temporary waivers of this requirement on behalf of states which included Florida through February 1, 2014. US Telecom also filed a Petition for Reconsideration and Clarification of the Lifeline Reform Order on April 2, 2012, which included in part, a request to reconsider the requirement of providing a copy of the Lifeline application form to the ETC. During these waiver periods, the Florida Public Service Commission (FPSC) had numerous telephone conference calls with FCC staff describing the Florida Lifeline Electronic Coordinated Enrollment process and explaining the reason why the requirement to provide hard-copy certifications of Lifeline applicants was unnecessary and should not apply to Florida.

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[1] 47 C.F.R. §54.407(d), 47 C.F.R. §54.410(b)(2)(ii), and 47 C.F.R. §54.410(c)(2)(ii).
[2] 47 C.F.R. §54.410(e).

As the June 1, 2013 waiver period was expiring and no FCC action had been taken on approving the Florida electronic enrollment program, the FPSC again contacted FCC staff and asked if there was anything else the FPSC could do to expedite the approval. FCC staff recommended the FPSC file a description of the Florida process through an Ex Parte filing in FCC Docket No. 11-42. The FPSC prepared the requested description with screen shots of the coordinated enrollment process and filed the documents on May 31, 2013, after notifying each Commissioner's office.

On August 30, 2013, the FCC released Order DA 13-1853 which extended the Waiver period for California, Colorado, Florida, Idaho, Nebraska, Oregon, Utah, and Vermont until the earlier of February 1, 2014, or once the state has come into compliance with the FCC's rules, or no longer requires a waiver because the ETCs in that state collect certification forms directly from consumers. The Waiver Order states that "...no later than November 1, 2013, each state still subject to this waiver must file a status update with the Bureau explaining the steps it has taken to bring its processes into compliance, and, if applicable, why it is unable to come into compliance by the end of the waiver period." In addition, the Waiver Order states that "...if an ETC or state believes that it will be unable to come into compliance and seeks a permanent waiver from the rules, it must provide in its request for permanent relief an explanation for why such relief is appropriate."

Florida has put in place a streamlined, efficient, and verifiable Lifeline Electronic Coordinated Enrollment process that does not have the capability of printing out a hard-copy Lifeline application. This advanced process involves a computer interface between the FPSC and the Florida Department of Children and Families (DCF) for Lifeline applicants who currently participate in Medicaid, the Supplemental Nutrition Assistance Program (SNAP), or the Temporary Cash Assistance (TCA)[3] program. The Florida process eliminates the need to require or maintain hard-copy Lifeline certification applications.

Only Lifeline applicants who have been verified as currently participating in Medicaid, SNAP, or the TCA program are approved through the Florida Lifeline Electronic Coordinated Enrollment process.[4] The DCF uses LexisNexis Risk Solutions to authenticate the identity of people applying online for public assistance. The LexisNexis technology helps the DCF confirm the identification of applicants before processing their benefit applications. By verifying and authenticating the identity of the applicant before processing their application, DCF knows whether the person seeking benefits is truly the individual applying for them.

Consumers already participating in Medicaid, SNAP, or TCA can also apply for Lifeline on the FPSC website. The FPSC mainframe computer automatically conducts a real-time query in the DCF computer to verify the applicant is currently participating in the program(s) checked

[3] Nationally known as Temporary Assistance to Needy Families (TANF).

[4] Applicants wishing to qualify for Lifeline using Supplemental Security Income, Federal Public Housing Assistance, Low-Income Home Energy Assistance Program, National School Lunch Free Lunch Program, or Bureau of Indian Affairs Programs can complete a hard-copy Lifeline application available on the FPSC Web site, and submit it to their telephone provider along with verification that they are currently participating in one of these programs.

by the applicant. If the DCF computer response message confirms participation in a qualifying Lifeline program, the FPSC computer automatically generates an e-mail to the appropriate ETC that it has a Lifeline applicant's information available for retrieval on the FPSC confidential website. In addition to the Florida Lifeline Electronic Coordinated Enrollment process, a computer interface is available for Florida ETCs to conduct a real-time query into DCF's database to determine if a Lifeline applicant is currently participating in Medicaid, SNAP, or the TCA program.

FPSC staff believes that the FCC requirement to provide hard-copy certifications is unnecessary, not cost effective, and would penalize Florida for having a Lifeline Electronic Coordinated Enrollment process that is efficient and streamlined. Staff is seeking Commission approval to file the attached status update and permanent waiver request by November 1, 2013.

cc: Lisa Harvey
Curt Kiser

Before the
Federal Communications Commission
Washington, D.C. 20554

DRAFT

In the Matter of	)	
	)	
Lifeline and Link Up Reform and Modernization	)	WC Docket No. 11-42
	)	

FLORIDA PUBLIC SERVICE COMMISSION

STATUS UPDATE OF FEDERAL COMMUNICATIONS COMMISSION LIMITED WAIVER OF 47 C.F.R. §54.407(d), 47 C.F.R. §54.410(b)(2)(ii), 47 C.F.R. §54.410(c)(2)(ii), and 47 C.F.R. §54.410(e) FOR THE STATE OF FLORIDA

AND

PETITION FOR PERMANENT WAIVER OF FEDERAL COMMUNICATIONS COMMISSION RULES 47 C.F.R. §54.407(d), 47 C.F.R. §54.410(b)(2)(ii), 47 C.F.R. §54.410(c)(2)(ii), and 47 C.F.R. §54.410(e)

CHAIRMAN RONALD A. BRISÉ

COMMISSIONER LISA POLAK EDGAR

COMMISSIONER ART GRAHAM

COMMISSIONER EDUARDO E. BALBIS

COMMISSIONER JULIE I. BROWN

October 24, 2013

INTRODUCTION AND SUMMARY

On February 6, 2012, the Federal Communications Commission ("FCC") released a Report and Order and Further Notice of Proposed Rulemaking (Order) regarding Lifeline and Link Up Reform and Modernization (FCC 12-11). The Order states that eligible telecommunications carriers (ETCs) must not seek reimbursement from the Federal universal service fund unless the ETC has received from the state Lifeline administrator or other state agency, a copy of the Lifeline subscriber's certification form.[5] The Order also requires state Lifeline administrators or other state agencies that are responsible for the initial determination of a subscriber's eligibility for Lifeline to provide each ETC with a hard-copy of each of the Lifeline certification forms beginning June 1, 2012.[6]

Lifeline applicants in Florida have several options when applying for Lifeline. A consumer can apply directly to the Florida ETC. If consumers wish to use income criteria for Lifeline qualification, they may apply for Lifeline through the Florida Office of Public Counsel (OPC).[7] A Florida consumer can request Lifeline when applying for Medicaid, Supplemental Nutrition Assistance Program (SNAP), or Temporary Assistance to Needy Families (TANF)[8] through the Florida Department of Children and Families (DCF) which is the administrator of those programs in Florida. The Florida Public Service Commission (FPSC) Lifeline Electronic Coordinated Enrollment process with the DCF has been in place since 2007. Consumers already participating in Medicaid, SNAP, or TANF can also apply for Lifeline on the FPSC website which will confirm in real-time, participation in a Lifeline-qualifying DCF program, without

[5] 47 C.F.R. §54.407(d), 47 C.F.R. §54.410(b)(2)(ii), and 47 C.F.R. §54.410(c)(2)(ii).
[6] 47 C.F.R. §54.410(e).
[7] Florida Statutes provide that the Florida Office of Public Counsel shall provide Lifeline applicant income criteria certification for each local exchange telecommunications company that has more than one million access lines and any wireless provider who elects to have OPC certify their income criteria applicants. See Section 364.10(2)(a), Florida Statutes.
[8] In Florida, TANF is known as Temporary Cash Assistance.

naming the particular program.[9] Modifications have been made to the process over the years as Lifeline requirements changed, including the attestations and certifications required by the Lifeline Reform Order. The Florida Lifeline Electronic Coordinated Enrollment process does not have the capability of printing out a hard-copy Lifeline application as required by FCC Rules 47 C.F.R. §54.407(d), 47 C.F.R. §54.410(b)(2)(ii), 47 C.F.R. §54.410(c)(2)(ii), and 47 C.F.R. §54.410(e).

On April 25, 2012, the United States Telecom Association (US Telecom), without consulting the FPSC, filed a Petition for Waiver of the hard-copy application requirement on behalf of twenty states including Florida.[10] On May 31, 2012, the FCC granted the US Telecom Waiver until December 1, 2012, for eleven states, the District of Columbia, and the U.S. Virgin Islands.[11] On November 28, 2012, US Telecom filed another Waiver Request asking the FCC to extend the Waiver period to June 1, 2013. On December 21, 2012, the FCC approved the US Telecom Waiver extension until June 1, 2013, for seven states and the US Virgin Islands.[12]

On May 6, 2013, US Telecom requested another Waiver extension until December 1, 2013. On August 30, 2013, the FCC approved the US Telecom Waiver extension for eight states including Florida, until the earlier of February 1, 2014, or once the state has come into compliance with the FCC's rules, or no longer requires a waiver because the ETCs in that state

[9] Applicants wishing to qualify for Lifeline using Supplemental Security Income, Federal Public Housing Assistance, Low-Income Home Energy Assistance Program, National School Lunch Free Lunch Program, or Bureau of Indian Affairs Programs can complete a hard-copy Lifeline application available on the FPSC Web site, and submit it to their telephone provider along with verification that they are currently participating in one of these programs.

[10] US Telecom also filed a Petition for Reconsideration and Clarification of the Lifeline Reform Order on April 2, 2012, which included in part, a request to reconsider the requirement of providing a copy of the Lifeline application form to the ETC.

[11] DA 12-863, Waiver Order for California, Colorado, District of Columbia, Florida, Idaho, Montana, Nebraska, Nevada, Oregon, the U.S. Virgin Islands, Utah, Vermont, and Washington .

[12] DA 12-2062, Waiver Order for the US Virgin Islands and the states of California, Colorado, Florida, Idaho, Oregon, Utah, and Vermont.

collect certification forms directly from consumers.[13] The August 30, 2013 Waiver Order stated that "...no later than November 1, 2013, each state still subject to this waiver must file a status update with the Bureau explaining the steps it has taken to bring its processes into compliance, and, if applicable, why it is unable to come into compliance by the end of the waiver period." In addition, the Waiver Order stated that "...if an ETC or state believes that it will be unable to come into compliance and seeks a permanent waiver from the rules, it must provide in its request for permanent relief an explanation for why such relief is appropriate."

During these Waiver periods, the FPSC had numerous telephone conference calls with FCC staff to describe the Florida Lifeline Electronic Coordinated Enrollment process and to explain the reason why the Florida process meets the FCC requirements, and why the obligation to provide hard-copy certifications of Lifeline applicants should not apply to Florida. As the June 1, 2013 waiver period was expiring, the FPSC again contacted the FCC and inquired if there was anything else the FPSC needed to do. The FCC recommended that the FPSC file a description of the Florida process as an Ex Parte filing in Docket No. 11-42. The FPSC prepared the requested description with screen shots of the Florida Lifeline Electronic Coordinated Enrollment process and filed the documents in Docket No. 11-42 on May 31, 2013.[14]

STATUS UPDATE OF FEDERAL COMMUNICATIONS COMMISSION LIMITED WAIVER OF 47 C.F.R. §54.407(d), 47 C.F.R. §54.410(b)(2)(ii), 47 C.F.R. §54.410(c)(2)(ii), and 47 C.F.R. §54.410(e) FOR THE STATE OF FLORIDA

Florida has put in place a streamlined, efficient, and verifiable Lifeline Electronic Coordinated Enrollment process that does not have the capability of printing out a hard-copy Lifeline application. The FPSC believes that the FCC requirement to provide hard-copy

[13] DA 13-1853, Waiver Order for California, Colorado, Florida, Idaho, Nebraska, Oregon, Utah, and Vermont.
[14] See http://apps.fcc.gov/ecfs/document/view?id=7022419940

certifications is unnecessary in Florida, not cost effective, and would penalize Florida for using Lifeline Electronic Coordinated Enrollment that is efficient and streamlined. The Florida Lifeline Electronic Coordinated Enrollment process allows ETCs to adhere to the requirements of the Lifeline Reform Order without the need to require or maintain hard-copy Lifeline certification applications.

The Florida Lifeline Electronic Coordinated Enrollment process was created to simplify and streamline Lifeline enrollment and verify an applicant's participation in Medicaid, SNAP, or TANF. The FPSC believes that hard-copy documentation of a Lifeline applicant's participation in a qualifying program is not necessary when Florida's Lifeline Electronic Coordinated Enrollment process is used for initial program eligibility. A Florida ETC can easily make a note in its records that the Florida Lifeline Electronic Coordinated Enrollment process was relied upon to confirm a consumer's initial eligibility for Lifeline, or the ETC could retain a copy of the notification it receives from the FPSC when Lifeline applicants are verified and approved. The FPSC believes that a permanent waiver of FCC Rules 47 C.F.R. §54.407(d), 47 C.F.R. §54.410(b)(2)(ii), 47 C.F.R. §54.410(c)(2)(ii), and 47 C.F.R. §54.410(e) is necessary.

PETITION FOR PERMANENT WAIVER OF FEDERAL COMMUNICATIONS COMMISSION RULES 47 C.F.R. §54.407(d), 47 C.F.R. §54.410(b)(2)(ii), 47 C.F.R. §54.410(c)(2)(ii), and 47 C.F.R. §54.410(e)

The FPSC believes that the FCC requirements listed below are unnecessary, cost-prohibitive, and burdensome when the Florida Lifeline Electronic Coordinated Enrollment Process is used for initial Lifeline enrollment. Therefore, the FPSC requests a Permanent Waiver of the following FCC rules:

47 C.F.R. §407(d)

In order to receive universal service support reimbursement, an eligible telecommunications carrier must certify, as part of each request for

reimbursement, that it is in compliance with all of the rules in this subpart, and, to the extent required under this subpart, has *obtained valid certification and re-certification forms for each of the subscribers for whom it is seeking reimbursement.* (emphasis added)

47 C.F.R. §410(b)(2)(ii)
Where a state Lifeline administrator or other state agency is responsible for the initial determination of a subscriber's eligibility, an eligible telecommunications carrier must not seek reimbursement for providing Lifeline service to a subscriber, based on that subscriber's income eligibility, unless the carrier has received from the state Lifeline administrator or other state agency:

(i) Notice that the prospective subscriber meets the income-eligibility criteria set forth in §§ 54.409(a)(1) or (a)(3); and

(ii) *A copy of the subscriber's certification that complies with the requirements set forth in paragraph (d) of this section.* (emphasis added)

47 C.F.R. §410(c)(2)(ii)
Where a state Lifeline administrator or other state agency is responsible for the initial determination of a subscriber's eligibility, when a prospective subscriber seeks to qualify for Lifeline service using the program-based eligibility criteria provided in §54.409, an eligible telecommunications carrier must not seek reimbursement for providing Lifeline to a subscriber unless the carrier has received from the state Lifeline administrator or other state agency:

(i) Notice that the subscriber meets the program-based eligibility criteria set forth in §§ 54.409(a)(2), (a)(3) or (b); and

(ii) *a copy of the subscriber's certification that complies with the requirements set forth in paragraph (d) of this section.* (emphasis added)

47 C.F.R. §410(e)
State Lifeline administrators or other state agencies that are responsible for the initial determination of a subscriber's eligibility for Lifeline *must provide each eligible telecommunications carrier with a copy of each of the certification forms* collected by the state Lifeline administrator or other state agency from that carrier's subscribers. (emphasis added)

FPSC AND FLORIDA DEPARTMENT OF CHILDREN AND FAMILIES (DCF) LIFELINE ELECTRONIC COORDINATED ENROLLMENT PROCESS

In 2010, the National Broadband Plan recommended that the FCC encourage state agencies responsible for Lifeline and Link Up to streamline benefit enrollment and suggested the

use of unified online applications for social services. (FCC 12-11, ¶171) The Florida Lifeline Electronic Coordinated Enrollment Process is consistent with the vision of the FCC. Florida implemented a streamlined, efficient, and verifiable Lifeline Electronic Coordinated Enrollment process to eliminate the possibility of fraud, waste, and abuse as was recommended in the National Broadband Plan and mentioned in FCC Order 12-11.

The FCC's March 4, 2011 Notice of Proposed Rulemaking also recommended use of a coordinated enrollment process to improve administrative efficiency and protect and improve program access. In this regard, the FCC stated:

> We also seek comment on ways to reduce barriers to participation in the program by service providers and low-income households, specifically through the use of coordinated enrollment with other social service assistance programs and the development of a national database that could be used for enrollment and verification of ongoing eligibility. These proposals are intended to improve administrative efficiency, improve service delivery, and protect and improve program access for eligible beneficiaries. (FCC 11-32, ¶ 151)

Moreover, the FCC stated:

> While we place limitations on how states' automatic enrollment processes can be utilized, we encourage coordinated enrollment and recognize coordinated enrollment as a best practice in light of the overwhelming support in the record and the benefits of coordinated enrollment (FCC 12-11, ¶174)

The FPSC has streamlined Florida Lifeline enrollment processes using current technologies, and reduced paperwork burdens for the FPSC and ETCs, which embodies the objectives mentioned in the Lifeline Reform Order.

> A number of states currently engage in or are implementing coordinated enrollment. For example, in 2007, Florida's Department of Children and Families (DCF) and the Florida Public Service Commission (FL PSC) established a coordinated enrollment system in which applicants to three Lifeline eligible programs (Food Stamps, Medicaid, and Temporary Assistance to Needy Families) can also apply for Lifeline benefits at the same time.
>
> When a consumer receiving benefits from DCF enrolls in one of these three DCF programs online, the consumer is also presented with the option to enroll in

> Lifeline. If the consumer affirmatively enrolls in Lifeline, the consumer selects an ETC from a list. The list of consumers and their ETC selections are sent to the FL PSC. The FL PSC then sends each ETC the list of consumers who selected that ETC as their Lifeline provider. (FCC 12-11 ¶175)

A Florida consumer applying for Medicaid, SNAP, or TANF must apply for the assistance through the Florida DCF which is the administrator of those programs in Florida. Included within the DCF's application is a question asking whether the applicant wants to receive a monthly discount on their phone service from the Florida Lifeline Assistance program.

If the applicants answer in the affirmative, they are asked if they presently have phone service and if so, what their phone number is and whose name is on the monthly bill. They are then asked to choose the name of their telephone provider from a drop-down menu which appears with the names of all the Florida ETCs. If an applicant checks that they do not presently have phone service but want to receive Lifeline Assistance, they are advised to contact their local provider and sign up for telephone service. The application then lists all the attestations and certifications required in the Lifeline Reform Order, and asks if the residential address listed on the application is permanent or temporary. The applicants have to check whether they have read and understand each of the attestations.

The DCF holds this information until a determination is made as to whether the applicant becomes approved for Medicaid, SNAP, or TANF. Once an applicant has been approved for one of these programs, and has indicated that he/she wants to participate in the Lifeline program, the DCF computer automatically sends a message to the FPSC computer indicating this person has been approved for a Lifeline qualifying program and has requested Lifeline Assistance.

The FPSC computer automatically queries the DCF message to retrieve the name of the applicant's ETC provider. The FPSC computer then generates an automatic message to the appropriate ETC advising them that it has a Lifeline applicant's information available for

retrieval on the FPSC's confidential website. The only time an ETC receives the message from the FPSC is when an applicant has been certified that they participate in Medicaid, SNAP, or TANF. The ETC can only view the Lifeline information of applicants who have applied to that specific ETC through the coordinated enrollment process.

The ETC retrieves the Lifeline applicant's information by logging in to the confidential FPSC website to download the spreadsheet with the names, addresses and other information of the applicants. In accordance with sections C.F.R. 54.410(b)(2)(i) and C.F.R. 54.410(c)(2)(i), the confidential FPSC website includes a statement affirming "The subscribers herein have complied with the Federal Communications Commission's (FCC) Lifeline eligibility requirements and have executed a certification form as required by the FCC." The spreadsheet which the ETC downloads indicates whether the application was originated on the DCF website or the FPSC (described below) website.

Only Lifeline applicants who have been verified as currently participating in Medicaid, the SNAP, or the TANF program and who have had their identity verified by DCF are approved through the Florida Lifeline Electronic Coordinated Enrollment process. The DCF uses LexisNexis Risk Solutions to authenticate the identity of people applying online for public assistance. The LexisNexis technology helps the DCF confirm the identification of applicants before processing their benefit applications. By verifying and authenticating the identity of the applicant before processing his/her application, the DCF knows whether the person seeking benefits is truly the individual applying for them.

By Florida Statute, ETCs have 60 days to place the applicant on Lifeline.[15] By FPSC rule, the ETC has to apply the Lifeline credit back to the date of the FPSC e-mail message sent to

[15] See Section 364.10(1)(f), Florida Statutes.

them advising that an applicant has been approved for Lifeline.[16] Personal identifying information of Lifeline applicants must be held confidential by Florida statute.[17] However, the statute provides that the applicant's information may be released to the applicable ETC for purposes directly connected with eligibility for, verification related to, or auditing of a Lifeline Assistance Plan.

FPSC ON-LINE LIFELINE COORDINATED ENROLLMENT PROCESS

Consumers already participating in Medicaid, SNAP, or TANF can apply for Lifeline on the FPSC website using English, Spanish, or Creole applications.[18] The applicants provide their name, address, telephone number, date of birth, and last four digits of their social security number. They indicate whether their address is permanent or temporary, and whether they have a different billing address. They select the name of their provider from a drop-down box listing all Florida ETCs, and then indicate whether they are participating in Medicaid, SNAP, or TANF. The application includes all the attestations and certifications required in the Lifeline Reform Order.

Once the applicant agrees to the terms and conditions at the bottom of the application and hits the submit button, the FPSC computer automatically conducts a real-time query in the DCF computer to verify the applicant is actually participating in the program(s) checked by the applicant. If the DCF computer response message confirms participation in a qualifying Lifeline program (without naming the particular program), the FPSC computer automatically generates an e-mail to the appropriate ETC that it has a Lifeline applicant's information available for retrieval on the FPSC confidential website. By Florida Statute, ETCs have 60 days to place the

[16] See Rule 25-4.0665(10)(b), Florida Administrative Code.
[17] See Section 364.107, Florida Statutes.
[18] See https://secure.floridapsc.com/(S(ob1zlcip3q4efr45gkyhz255))/public/lifeline/lifelineapplication2.aspx.

applicant on Lifeline.[19] By FPSC rule, the ETC has to apply the Lifeline credit back to the date of the FPSC e-mail message sent to them advising that an applicant has been approved for Lifeline.[20]

If the DCF computer cannot verify current participation in the Lifeline qualifying program, the FPSC generates a letter to the applicant notifying them that the FPSC could not confirm participation in the Lifeline qualifying program they checked. The FPSC includes a hard-copy Lifeline application with the letter along with a listing of all Florida ETCs and FPSC telephone numbers if assistance is needed.

THE NATIONAL LIFELINE ACCOUNTABILITY DATABASE

The National Lifeline Accountability Database has been designed to help carriers identify and resolve duplicate claims for Lifeline Program-supported service and prevent future duplicates by conducting a nationwide real-time check if the consumer is already receiving a Lifeline Program-supported service. 47 C.F.R. §54.404 (b)(6) requires the following information for the database:

> Eligible telecommunications carriers must transmit to the Database in a format prescribed by the Administrator each new and existing Lifeline subscriber's full name; full residential address; date of birth and the last four digits of the subscriber's social security number or Tribal Identification number, if the subscriber is a member of a Tribal nation and does not have a social security number; the telephone number associated with the Lifeline service; the date on which the Lifeline service was initiated; the date on which the Lifeline service was terminated, if it has been terminated; the amount of support being sought for that subscriber; and the means through which the subscriber qualified for Lifeline.

The following information is provided to the ETC when a Lifeline applicant is approved through the Florida PSC/DCF Coordinated enrollment Process: First Name; Last Name; Address 1;

[19] See Section 364.10(1)(f), Florida Statutes.
[20] See Rule 25-4.0665(10)(b), Florida Administrative Code.

Address 2; City; Zip Code; Zip 4; State; Status (P or T) for permanent or temporary address; Telephone number; Application date; Last 4 digits of Social Security Number; Agency (DCF or FPSC); DOB; and, Qualifying Public Assistance Program(s) – this will include SNAP, Medicaid, and/or TANF. Provision of this information allows the Florida Lifeline Electronic Coordinated Enrollment process to make available all necessary information for Florida ETCs to comply with the National Lifeline Accountability Database requirements in 47 C.F.R. §54.404 (b)(6).

DOCUMENTATION OF A LIFELINE APPLICANT'S PARTICIPATION IN A QUALIFYING PROGRAM IS NOT NECESSARY WHEN FLORIDA'S LIFELINE COORDINATED ENROLLMENT PROCESS IS USED FOR INITIAL PROGRAM ELIGIBILITY.

The Florida Lifeline Electronic Coordinated Enrollment process uses three federal programs (Medicaid, SNAP, and TANF) to verify a Lifeline applicant's participation in a Lifeline-qualifying program. The Lifeline Reform Order specifies that documentation of an applicant's participation in a qualifying federal program is not required when a state or federal database such as in Florida is used to determine eligibility. Specifically, paragraph 98 of the Lifeline Reform Order provides that:

> Where ETCs access state or federal databases to make determinations about consumer eligibility for Lifeline, we do not require ETCs to obtain from a new subscriber documentation of his or her participation in a qualifying federal program. The ETC or its representative must note in its records what specific data was relied upon to confirm the consumer's initial eligibility for Lifeline (*e.g.*, name of a state database.) This rule will reduce administrative burdens on ETCs by allowing them to leverage existing systems and processes. In states where the ETC is not responsible for the initial determination of consumer eligibility, a state agency or third-party administrator, as applicable, may query the database in lieu of the ETC doing so.

Because the Florida Lifeline Electronic Coordinated Enrollment uses the DCF database using the same vetted information as DCF, the same documentation requirements should apply. The Florida Lifeline Electronic Coordinated Enrollment process was created to streamline Lifeline

enrollment and verify an applicant's participation in Medicaid, SNAP, or TANF. The FPSC believes that hard-copy documentation of a Lifeline applicant's participation in a qualifying program is not necessary when Florida's Lifeline Electronic Coordinated Enrollment process is used for initial program eligibility. All applicant information was verified by DCF through their benefits enrollment process. A Florida ETC can easily make a note in its records that the Florida Lifeline Electronic Coordinated Enrollment process was relied upon to confirm a consumer's initial eligibility for Lifeline, or the ETC could retain a copy of the notification it receives from the FPSC when Lifeline applicants are verified and approved.

GOOD CAUSE EXISTS TO GRANT A PERMANENT WAIVER OF FCC RULES 47 C.F.R. §54.407(d), 47 C.F.R. §54.410(b)(2)(ii), 47 C.F.R. §54.410(c)(2)(ii), and 47 C.F.R. §54.410(e)

The FCC may waive its rules for good cause shown. 47 C.F.R. §1.3 provides the following:

> The provisions of this chapter may be suspended, revoked, amended, or waived for good cause shown, in whole or in part, at any time by the Commission, subject to the provisions of the Administrative Procedure Act and the provisions of this chapter. Any provision of the rules may be waived by the Commission on its own motion or on petition if good cause therefor is shown.

Good cause includes the existence of particular facts that make strict compliance with the rule inconsistent with the public interest.[21] The FCC may also take into account considerations of hardship, equity, or more effective implementation of public policy on an individual basis.[22]

Requiring hard-copy signed applications/certifications would present an economic hardship on the FPSC, the DCF, and the Florida ETCs, and may not even be possible with Florida's streamlined Lifeline Electronic Coordinated Enrollment process which averaged

[21] *Northeast Cellular Telephone Com. v. FCC*, 897 F.2d 1164,1166 (D.C. Cir. 1990).
[22] *WAIT Radio v. FCC*, 418 F.2d 1153, 1159 (D.C. Cir. 1969), *cert. denied* 409 U.S. 1027 (1972); *Northeast Cellular Telephone Com. v. FCC* at 1166.

receiving over 9,000 Lifeline applications/month for the first eight months of 2013. The Lifeline application is embedded within the DCF application for assistance and cannot be retrieved and printed. Changing the present coordinated enrollment process would be cost-prohibitive and time consuming. The FPSC and the DCF have limited resources and fixed budgets dedicated to the administration of the Lifeline program. The Florida DCF also has many other programs which they administer including Adult Protective Services, Child Care, Domestic Violence, TANF, SNAP, Medicaid, Child Welfare, Homelessness, Refugee Services, and Substance Abuse and Mental Health. The Lifeline coordinated enrollment program is only one small part of their overall mission, and it took a number of years to create a process within the DCF application for consumers to request Lifeline and make all the required attestations and certifications. Any changes would be extremely costly, time consuming, and place additional administrative burdens on the FPSC, the DCF, and the Florida ETCs. Requiring hard-copy application certifications to ETCs does nothing to enhance the validity of the subscriber's eligibility when the Florida Lifeline Electronic Coordinated Enrollment process is used. It would be extremely difficult if not impossible to isolate the required certification and application information, create images of these documents and provide them to the relevant ETC.

Granting a permanent waiver of these rules would also be in the public interest. The present Florida Lifeline Electronic Coordinated Enrollment process provides easy access for consumers, and verifies in real time whether an applicant is currently participating in Medicaid, SNAP, or TANF.[23] Florida households are presently the number one recipients of SNAP benefits in the United States with 1,952,890 households receiving SNAP benefits in June,

[23] Florida has an estimated 929,200 participants in Lifeline as of August 2013, according to the USAC disbursement database.

2013.[24] Over 74 percent of Lifeline applicants use the SNAP program to qualify for Lifeline when using the Florida Lifeline Electronic Coordinated Enrollment process. The FPSC has streamlined Lifeline enrollment processes using current technologies, and reduced paperwork burdens for the FPSC, the DCF, and ETCs which embodies the objectives mentioned in the Lifeline Reform Order.

CONCLUSION

The FPSC believes the FCC's efforts to comprehensively reform and modernize the Lifeline program substantially strengthens protections against waste, fraud, and abuse in the Lifeline program and will limit the growth of the program to reduce the burden on all who contribute to the Universal Service Fund. As a net contributor, Florida contributed $535 million to the Universal Service Fund and received $245 million in 2011.[25]

The Florida PSC has been recognized by the FCC as being at the forefront of eliminating fraud, waste, and abuse in the universal service program. Florida was one of two states personally commended by FCC Chairman Julius Genachowski for formidable efforts to identify and eliminate fraud in the Lifeline Assistance program. In his December 12, 2011 letter, Chairman Genachowski praised the states' efforts to end any potential fraud in the Universal Service Fund, specifically recognizing actions by Florida and Wisconsin, and also urged state commissions to join the FCC's national effort "to reform the Lifeline program…and to take swift and strong action when necessary to protect the program."

Florida has put in place a streamlined, efficient, and verifiable Lifeline Electronic Coordinated Enrollment process that does not have the capability of printing out a hard-copy

[24] United States Department of Agriculture SNAP program data. http://www.fns.usda.gov/pd/SNAPmain.htm
[25] 2012 Universal Service Monitoring Report.

Lifeline application. The Florida Lifeline Electronic Coordinated Enrollment process allows ETCs to adhere to the requirements of the Lifeline Reform Order without the need to require or maintain hard-copy Lifeline certification applications.

The FPSC believes that a Permanent Waiver for Florida of FCC Rules 47 C.F.R. §54.407(d), 47 C.F.R. §54.410(b)(2)(ii), 47 C.F.R. §54.410(c)(2)(ii), and 47 C.F.R. §54.410(e) is appropriate since there are special circumstances which warrant a deviation from the these rules, and such deviation will serve the public interest. The FPSC believes that the FCC requirement to provide hard-copy certifications is unnecessary in Florida, not cost effective, and would penalize Florida's Lifeline Electronic Coordinated Enrollment process for being efficient and streamlined. The FPSC encourages the FCC to consider the facts noted in this petition and grant Florida a permanent waiver of these rules.

Respectfully submitted,
/ s /
Adam J. Teitzman, Attorney Supervisor
Office of the General Counsel
FLORIDA PUBLIC SERVICE COMMISSION
2540 Shumard Oak Boulevard
Tallahassee, Florida 32399-0850
(850) 413-6082

DATED: October 24. 2013

Attachment 2

State of Florida

Public Service Commission

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

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

DATE: October 15, 2013

TO: Braulio L. Baez, Executive Director

FROM: Phillip O. Ellis, Engineering Specialist III, Division of Engineering POE BV TJB

RE: Draft Review of the 2013 Ten-Year Site Plans

CRITICAL INFORMATION: Please place on the October 24, 2013, Internal Affairs Agenda. Approval by the Commission is required by December 31, 2013.

Pursuant to Section 186.88(1), 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 Robert Graves know if you have any questions or need additional information in reference to the attached document.

Thank you.

POE

Attachment
cc: Robert Graves
Paul Vickery
Tom Ballinger
Lisa Harvey

DRAFT

Review Of The

2013 Ten-Year Site Plans

For Florida's Electric Utilities

Florida Public Service Commission

Tallahassee, FL
October 2013

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Statewide Perspective

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List of Ten-Year Site Plan Utilities

Investor-Owned Electric Utilities

FPL	Florida Power & Light Company
DEF	Duke Energy Florida, Inc. (formerly Progress Energy Florida, Inc.)
TECO	Tampa Electric Company
GPC	Gulf Power Company

Municipal Electric Utilities & Rural Electric Cooperatives

FMPA	Florida Municipal Power Agency
GRU	Gainesville Regional Utilities
JEA	JEA (formerly Jacksonville Electric Authority)
LAK	Lakeland Electric
OUC	Orlando Utilities Commission
SEC	Seminole Electric Cooperative
TAL	City of Tallahassee Utilities

List of Acronyms

AB	Agricultural Byproducts (Biomass)
CC	Combined Cycle
CR3	Crystal River Unit 3 (Nuclear)
CT	Combustion Turbine
DACS	Department of Agriculture and Consumer Services
DEP	Department of Environmental Protection
DR	Demand Response
DSM	Demand-Side Management
EIA	Energy Information Administration
EPA	Environmental Protection Agency
F.A.C.	Florida Administrative Code
F.S.	Florida Statutes
FEECA	Florida Energy Efficiency & Conservation Act
FRCC	Florida Reliability Coordinating Council
GWh	Gigawatt-hour
IC	Internal Combustion Generator
IGCC	Integrated Gasification Combined Cycle
IL	Interruptible Load
IOU	Investor-Owned Utility
LM	Load Management
MMBtu	Million British Thermal Units
MSW	Municipal Solid Waste
MW	Megawatt
NEL	Net Energy for Load
NUC	Nuclear Generation
NUG	Non-Utility Generator
OBS	Other Biomass Solids (Biomass)
PPSA	Power Plant Siting Act
QF	Qualifying Facilities
RPS	Renewable Portfolio Standard
SACE	Southern Alliance for Clean Energy
ST	Steam Generator
TLSA	Transmission Line Siting Act
TYSP	Ten-Year Site Plan
WDS	Wood Waste Solids (Biomass)

Executive Summary

Pursuant to Section 186.801(1), Florida Statutes (F.S.), each generating electric utility must submit to the Florida Public Service Commission (Commission) a Ten-Year Site Plan (TYSP or Plan) which estimates the utility's power generating needs and the general locations of its proposed power plant sites over a ten-year planning horizon. The TYSPs of Florida's electric utilities are designed to give state, regional, and local agencies advance notice of 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 study of the 2013 TYSPs for Florida's electric utilities, filed by eleven reporting utilities.[1]

All findings of the Commission are made available to the Department of Environmental Protection (DEP) for its consideration at any subsequent electrical power plant site certification proceedings pursuant to the Power Plant Siting Act (PPSA).[2] In addition, this document is forwarded to the Department of Agriculture and Consumer Services (DACS) pursuant to Section 377.703(2)(e), F.S., which requires the Commission to provide a report on electricity and natural gas forecasts. A copy of this report is also posted on the Commission's website and is available to the public.

Review of the Ten-Year Site Plans

Load & Demand Forecasting

The first step in any resource planning process is to focus on the efficient use of electricity by consumers. Government mandates, such as building codes and appliance efficiency standards, provide the starting point for increasing energy efficiency. Customer choice is the next step in reducing the state's need for electricity. Consequently, educating consumers to make smart energy choices is particularly important.

Florida's utilities can efficiently serve their customers by offering demand-side management (DSM) and conservation programs designed to use fewer resources at lower cost. Under the Florida Energy Efficiency and Conservation Act (FEECA), the Commission is required to establish annual numeric goals for seasonal peak demand and annual energy consumption reductions.[3] The Commission has already begun the next goal-setting proceeding, which will be completed by the end of 2014.

Florida's utilities project considerable demand and energy savings over the planning period, with conservation and load management programs by 2022 reducing the system's total summer peak demand by over 9,200 megawatts (MW), and annual energy consumption by over

[1] Investor-owned utilities (IOUs) filing 2013 TYSPs include Florida Power & Light Company (FPL), Duke Energy Florida, Inc. (DEF) which filed under its previous name, Progress Energy Florida, Inc., Tampa Electric Company (TECO), and Gulf Power Company (GPC). Municipal utilities filing 2013 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 2013 TYSP.

[2] The Power Plant Siting Act is Sections 403.501 through 403.518, Florida Statutes

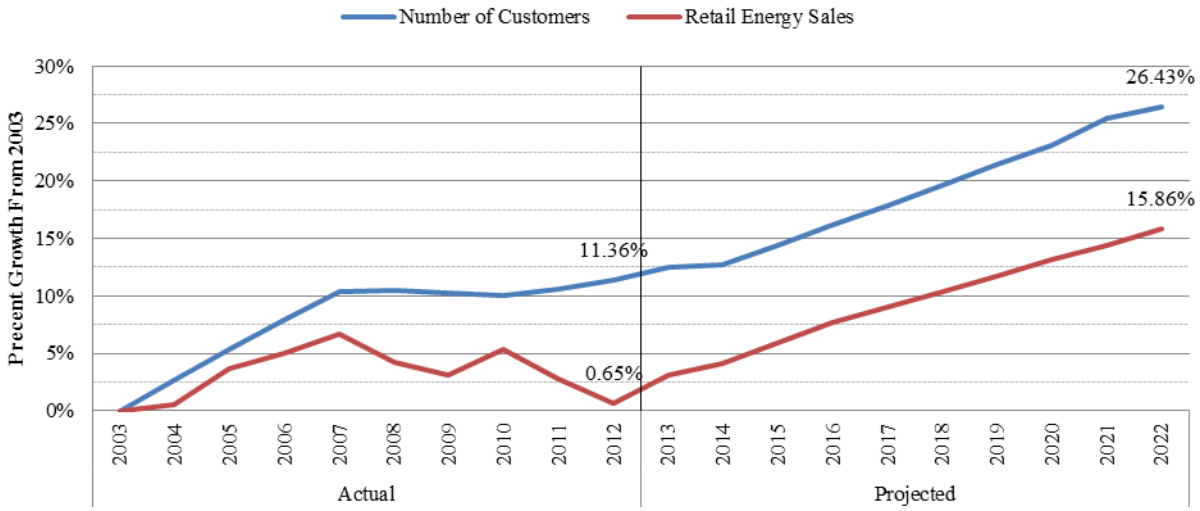
[3] Sections 366.80 through 366.85 and Section 403.519, F.S.

14,500 gigawatt-hours (GWh). Including these reductions, Florida is forecasted to experience by 2022 a net firm summer peak demand of 51,552 MW and annual net energy for load of 270,797 GWh.

Over the last ten years, the total number of electric customers in Florida has increased by 11.4 percent. Primarily this growth took place between 2003 and 2007, before the recession, after which customer growth plateaued, with the annual average growth rate dropping from 2.5 percent to a tenth of that figure, at 0.2 percent, including two years of slight negative growth. Forecasts estimate a higher rate of growth over the next ten years, at an annual average of 1.2 percent, below the average rate before the recession.

By comparison, retail energy sales in 2012 have only increased 0.6 percent over the past ten years. Retail energy sales followed a similar growth pattern as customer growth before 2007, but experienced an overall decline since the 2007 peak. Forecasts for energy sales also estimate a growth, at an annual average rate of 1.4 percent. This rate is also below the growth rate experienced before the recession, but is slightly higher than customer growth. Retail energy sales are anticipated to exceed the 2007 peak by 2016. Figure 1 details these trends below for number of customers and retail energy sales.

Figure 1: State of Florida - Customer and Retail Energy Sale Growth Since 2003



Source: 2013 FRCC Regional Load & Resource Plan

Renewable Generation

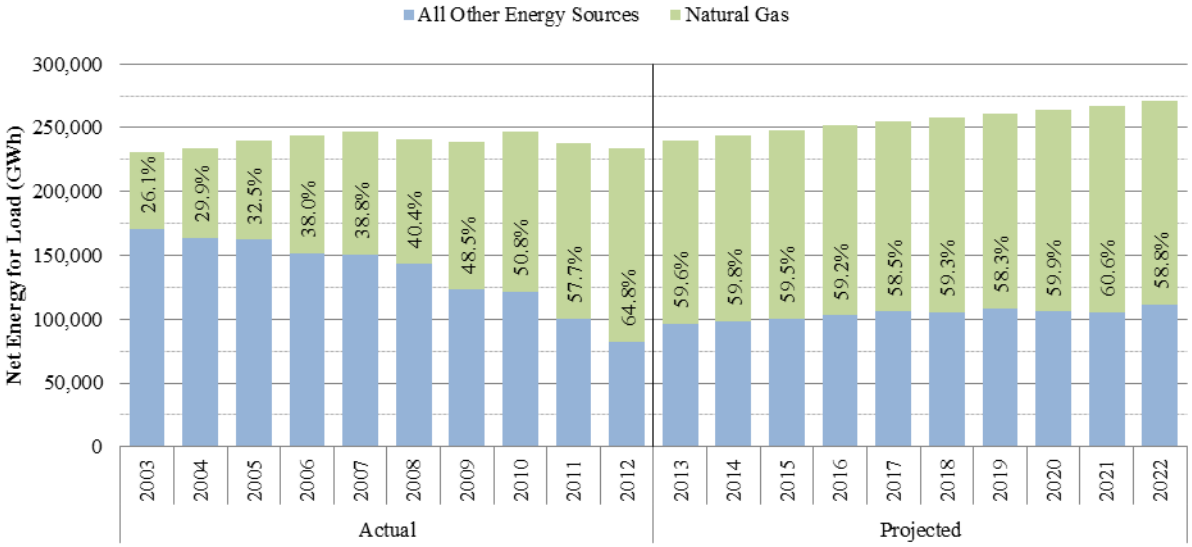
Renewable resources continue to expand in Florida, with approximately 1,470 MW of renewable generation currently operating in Florida. Presently, municipal solid waste (MSW) and biomass each represent roughly a third of renewable generation in Florida. Other major types of renewable generation operating in the state include waste heat, hydroelectric, landfill gas, and solar.

Over the planning horizon, approximately 966 MW of additional renewable generation is planned in Florida. The majority of these additions are solar and biomass. While these new projects represent a significant increase from the existing total, renewable generation continues to provide a relatively small contribution towards the reduction of the state's reliance on fossil fuels.

Traditional Generation

Natural gas is anticipated to remain the dominant fuel over the planning horizon, with usage in 2012 increasing to 64.8 percent of the state's net energy for load (NEL), up from 57.7 percent of NEL in 2011. Figure 2 below illustrates the increasing use of natural gas as a generating fuel for the electricity production during the last ten years, and the projected use during the next decade. State-wide, natural gas usage is expected to decline slightly from its current peak, to 58.8 percent in 2022. This is due to projected increases in nuclear generation, and a limited impact of new environmental compliance requirements.

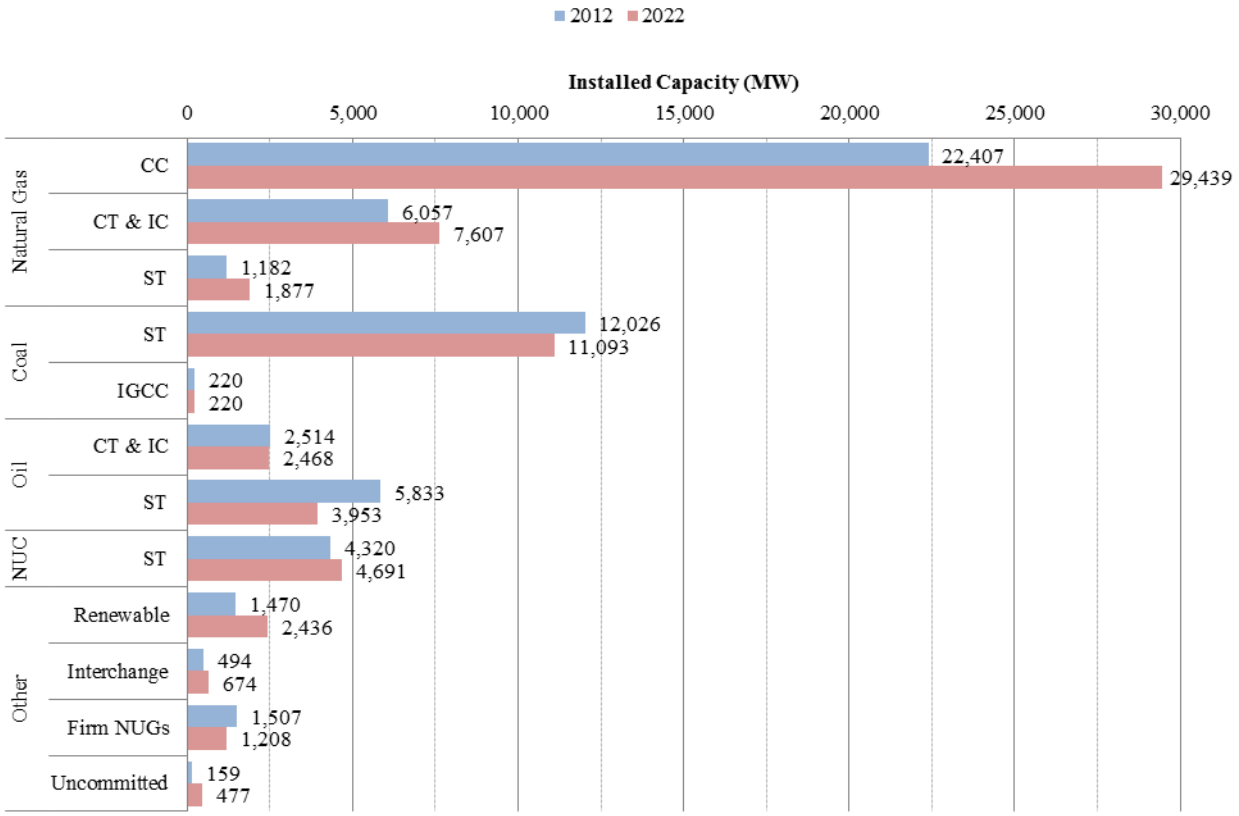
Figure 2: State of Florida - Natural Gas Usage (History & Forecast)



Source: 2013 FRCC Regional Load & Resource Plan

Generating capacity within the State of Florida is anticipated to grow to meet the increase in customer demand, with approximately 9,960 megawatts (MW) of new utility-owned generation added over the planning horizon. This figure represents an increase from last year's TYSPs, which estimated the need for about 7,200 MW new generation. Based on the 2013 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 ten-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. Retirements primarily consist of oil-fired and coal-fired steam generation, in addition to DEF's Crystal River Unit 3 (CR3), one of the five existing nuclear units in Florida.

Figure 3: State of Florida - Installed Capacity (Existing & Projected)



Source: 2013 TYSPs, 2013 FRCC Regional Load & Resource Plan

Future Commission Actions

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

These EPA rules will limit allowable emissions from new and existing power plants for a variety of pollutants, including mercury, other heavy metals, organic toxics, particulates, sulfur oxides, and nitrogen oxides. While many facilities within the state already have sufficient emissions control technologies to comply with these rules, some will require installation of new equipment to bring generators into compliance. Other rules address concerns relating to cooling water's impact on aquatic life and the disposal of coal ash. All of these activities will require new investment and the potential for extended outages of some generating units, which will require careful planning to minimize any impact on system reliability.

At this time, GPC's coal-fired Plant Scholz and DEF's Crystal River units 1 and 2 are the only plants anticipated to be retired as a result of any of these regulations. Additionally, DEF's Suwanee River Units 1-3, which can use either residual oil or natural gas, will cease residual oil operations in order to comply with the MATS rule. Several of the TYSP utilities have provided preliminary estimates based upon known and proposed rule language, and with a range between $2.4 and $5.5 billion, which may not encompass all associated potential costs.

As noted previously, the primary purpose of this review of the utilities' TYSPs is to provide information regarding new electric power plants to the DEP for its use in the certification process. Table 1 displays those generation facilities included in the 2012 TYSPs that have not yet received a certification under the PPSA by the Commission. Certification is generally anticipated at four years in advance of the in-service date for a natural gas-fired combined cycle unit.

Table 1: State of Florida - Proposed Generation Requiring Commission Approval

Utility	Generating Unit Name	Summer Capacity (MW)	In-Service Date
DEF	Unnamed CC 1	1,189	06/2018
DEF	Unnamed CC 2	1,189	06/2020
SEC	Unnamed CC 1	192	12/2020
SEC	Unnamed CC 2	192	12/2020

Source: 2013 TYSPs

While the Commission certifies transmission lines under the Transmission Line Siting Act (TLSA), there are none projected during the planning period that have not already been approved by the Commission.

Conclusion

The Commission has reviewed the 2013 TYSPs filed by the eleven reporting utilities, as well as supplemental data provided through data requests, 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 does continue to monitor the increased dependence on natural gas for electricity production, and the impact of this reduction in fuel diversity on the state. While low prices for natural gas have made it the dominant fuel, its history of price volatility raises the specter of increased costs should there be disruptions in natural gas production, supply, or markets.

Based on its review, the Commission finds the 2013 TYSPs filed by the reporting utilities, augmented with supplemental data provided, to be suitable for planning purposes. Since the TYSP is 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 TYSP at a public hearing.

Introduction

The Ten-Year Site Plans (TYSPs or Plans) of Florida's electric utilities are 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. Because the TYSPs are considered to be planning documents and can contain tentative data, they may not necessarily contain sufficient information to allow regional planning councils, water management districts, and other reviewing agencies to evaluate site-specific issues within their respective jurisdictions. Each utility is responsible for providing detailed information based on individual assessments during certification proceedings under the Power Plant Siting Act (PPSA), Sections 403.501-403.518, Florida Statutes (F.S.), or the Transmission Line Siting Act (TLSA), Sections 403.52-403.5365, F.S. In addition, other regulatory processes may require utilities to provide additional information as needed.

Statutory Authority

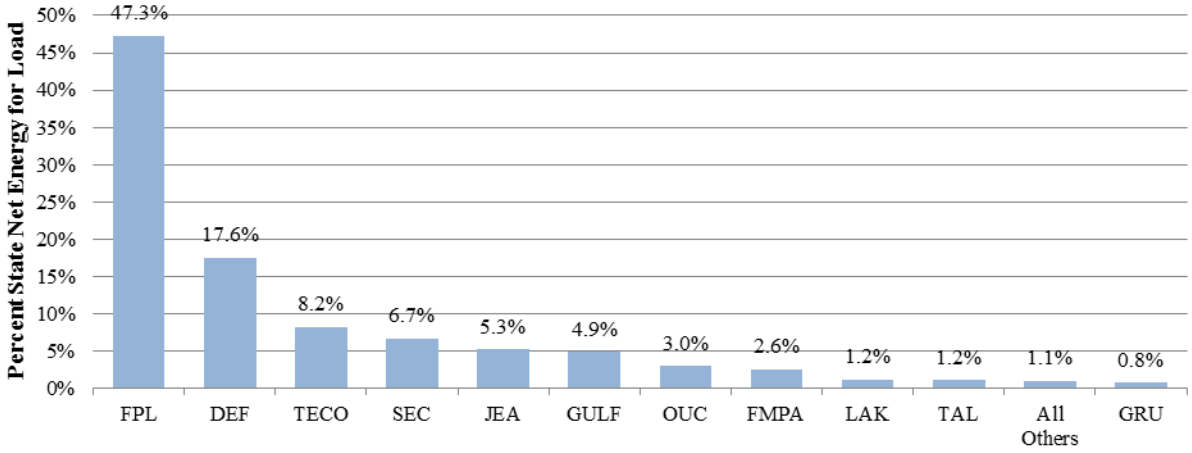
Section 186.801, F.S., requires that all major generating electric utilities submit a TYSP to the Commission for annual review. Section 377.703(2)(e), F.S., requires the Commission to analyze these plans and provide natural gas and electricity forecasts to the Department of Agriculture and Consumer Services (DACS). 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.

Florida is served by 58 electric utilities, including 5 investor-owned utilities (IOUs), 35 municipal utilities, and 18 rural electric cooperatives. 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 TYSP, at least once every two years. In 2013, eleven utilities filed TYSPs, including 4 IOUs, 6 municipal utilities, and 1 rural electric cooperative. [4]

Figure 4 below illustrates each TYSP utility's representative share of the state's net energy for load for 2012. In total, the investor-owned TYSP utilities represent 78 percent of net energy for load (NEL). Those utilities which are not required to file a TYSP make up the approximately 1 percent of the state's NEL.

[4] IOUs filing 2013 TYSPs include Florida Power & Light Company (FPL), Duke Energy Florida, Inc. (DEF) which filed under its previous name, Progress Energy Florida, Inc., Tampa Electric Company (TECO), and Gulf Power Company (GPC). Municipal utilities filing 2013 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 2013 TYSP.

Figure 4: TYSP Utilities - Share of State Net Energy for Load



Source: 2013 TYSPs, 2013 FRCC Load & Resource Plan

As outlined in the Commission's rules, each utility's TYSP contains projections of the utility's electric power needs, fuel requirements, and general location of proposed power plant sites and major transmission facilities. The utilities provide historic and projected information on existing generating capacity, customer base and energy usage, impact of demand-side management, fuel consumption, fuel diversity, anticipated reserve margin, and proposed new generating units and transmission.

In accordance with Section 186.801, F.S., the Commission performs a preliminary study of each TYSP and makes a determination as to whether it is suitable or unsuitable. This determination is non-binding, and is made in recognition that the information provided is tentative, and is subject to change by the utility upon written notice. The results of the Commission's study are contained in this report, Review of the 2013 Ten-Year Site Plans, and are forwarded to the DEP for use in subsequent power plant siting proceedings.

Information Sources for the Report

Contained in each utility's TYSP is a series of required tables which provide detailed information on a number of items. This information, supplemented by additional data requests, provides the basis of the Commission's review.

The Florida Reliability Coordinating Council (FRCC) is also an important source of information for the Commission's review. Each year, the FRCC publishes its Regional Load and Resource Plan which contains aggregate data on demand and energy, capacity and reserves, and proposed new generating units and transmission line additions, both for Peninsular Florida and for the state as a whole. The primary focus of the FRCC is the reliability of the electrical system for Peninsular Florida. In addition to its *2013 Regional Load and Resource Plan*, the Commission used the FRCC's *2013 Reliability Assessment* as a resource in the production of this review. The Commission held a public workshop on September 25, 2013, to facilitate discussion of the annual planning process and the Regional Load & Resource Plan and to allow for public comments on the TYSPs that were filed with the Commission. In addition to the FRCC, the

Sierra Club, also representing Earthjustice, and Southern Alliance for Clean Energy (SACE) made presentations at the workshop. Energy Conservation was the primary topic, with discussion on various changes in building codes, increased customer education, and utility programs reviewed by the Commission. Both the Sierra Club and SACE were aware of the Commission's open dockets to review utility energy conservation goals later next year.

Structure of the Report

This report is divided into multiple sections. The Statewide perspective provides a look at the impact of all planned unit additions to the State as a whole, and is intended as a resource for those seeking an understanding of Florida's energy systems. Individual utility reports focus on the issues facing each electric utility and its unique situation. Lastly, Appendix A contains comments received from various review agencies, local governments, and others that have been collected and included in this report.

Conclusions

As discussed in each of the individual utility's reviews, the Commission's review of the eleven reporting utilities' 2013 TYSPs finds them all suitable for planning purposes. Through the review process, the Commission has determined that the projections of load growth appear reasonable, and that reporting utilities have identified sufficient additional generation facilities to maintain an adequate supply of electricity at a reasonable cost.

Since the TYSP is 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 any docketed matters before the Commission. The Commission may address any concerns raised by a utility's TYSP at a public hearing.

Statewide Perspective

Load and Energy Forecast

Forecasting load growth is the first component of system planning for Florida's electric utilities. In order to maintain a reliable system, utilities must stay abreast of changes in customer base as well as trends in demand and energy consumption. Utilities perform load and energy forecasts to estimate the amount and timing of future capacity needs, taking into consideration the number and type of customers served, changes in customer usage patterns, impacts of mandated energy efficiency standards, new technologies, and demand-side management (DSM) programs.

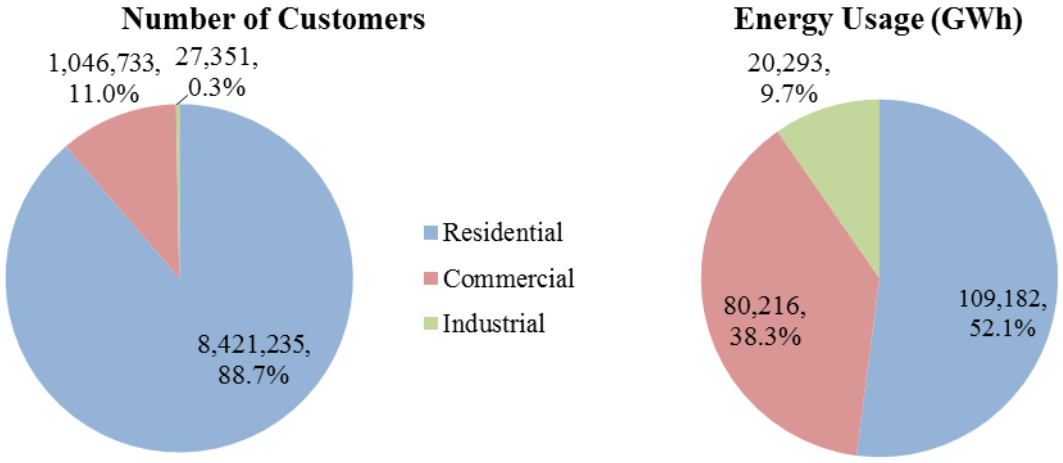
Historical data forms the foundation for utility load and energy forecasts. These sets of data include energy usage patterns, trends in population growth, economic variables, and weather data for each utility's service territory. Econometric forecast models are then used to quantify the historical impact of population growth, economic conditions, and weather on energy usage patterns.

Finally, sets of forecast assumptions on future population growth, economic conditions, and weather are assembled and together with the forecast models, yield the final demand and energy forecasts. Each utility's peak demand and energy forecasts serve as a starting point for determining if and when new capacity additions are needed to reliably and efficiently serve the anticipated load.

Florida's Electricity Customer Composition

Florida is dominated by residential electric customers, which make up a majority in both number of customers and retail energy sales, as shown in Figure 5 below. While commercial and industrial customers may be lower in number, they consume far more per customer, and combined represent the other half of energy consumed in Florida.

Figure 5: State of Florida - Number of Customers and Energy Usage by Class

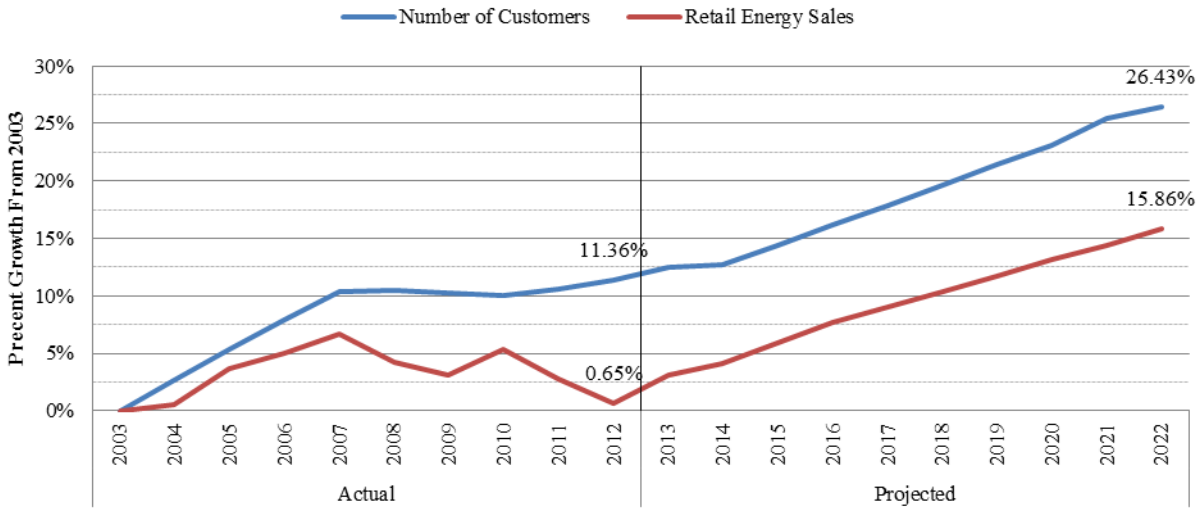


Source: 2013 FRCC Regional Load & Resource Plan

Growth in Customer Base and Consumption

Florida traditionally has been a high growth state, with significant annual increases in both customers and retail energy sales. The impact of the financial crisis changed these tendencies, with customer growth plateauing and retail energy sales declining from their 2007 peak, with an annual increase only in 2010, associated with extreme winter weather. Over the last ten years, Florida has experienced a growth in customers of 11.36 percent, but retail energy sales in 2012 were only 0.65 percent higher than 2003. These trends are illustrated in Figure 6 below.

Figure 6: State of Florida - Customer and Retail Energy Sale Growth Since 2003



Source: 2013 FRCC Regional Load & Resource Plan

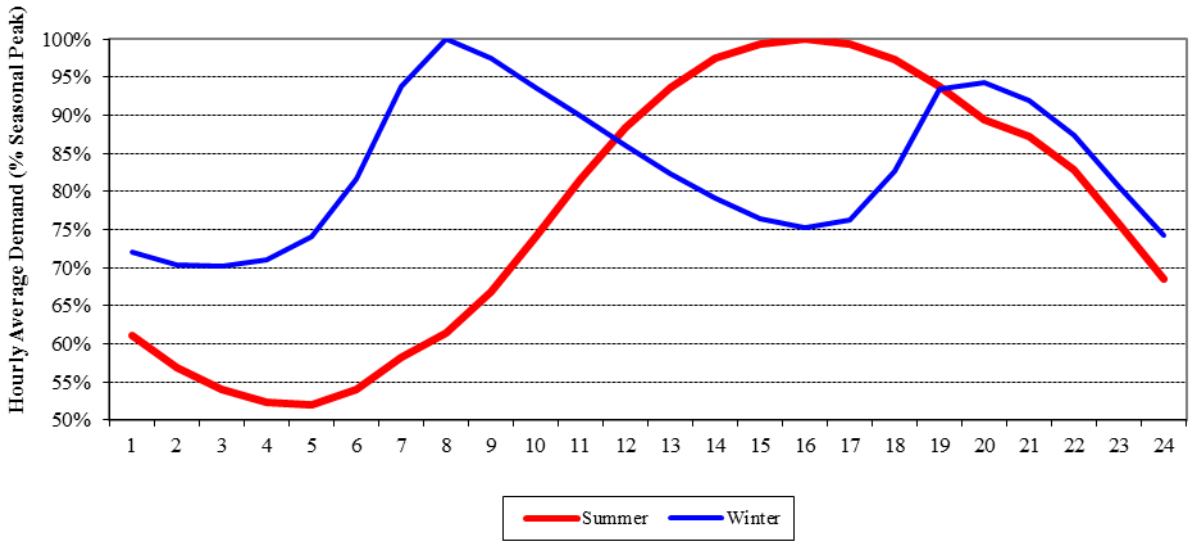
Customer growth and usage is projected to increase throughout the planning period, although at a slower pace than at the beginning of the last decade, with retail energy sales expected to exceed its 2007 peak by 2016. This is primarily based on assumptions of population growth and improving economic indicators. The current gap between number of customers and retail energy sales is projected throughout the planning period.

Seasonal Peak Demand Forecast

Since there exists no economically feasible means to store electricity at the grid-scale, electric utilities must supply electricity near instantaneously to the time of its consumption. For a majority of the time, system demand is significantly less than the daily peak. However, system peak demand determines the timing of new generation needs, and is driven by seasonal weather patterns. With a growing customer base dominated by residential customers, both the rate of growth and usage patterns are important considerations in planning sufficient future generation to meet the state's projected customer load.

Figure 7 illustrates typical daily load curves for each season, which shows evidence of the influence of residential customers. In summer, air-conditioning demand causes a steady climb in the morning and a peak in early evening, before declining into the evening. In contrast, winter's demand curve is dominated by electric heating and water heating, causing a rapid peak in mid-morning and a second peak in the late evening.

Figure 7: State of Florida - Daily Load Curve Example

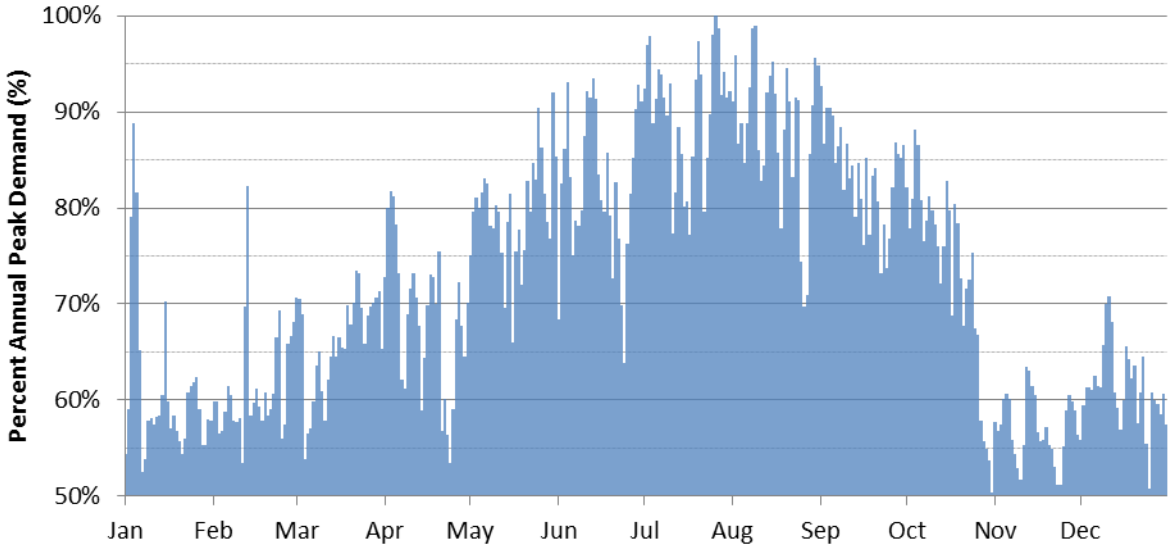


Source: TYSP Utilities Data Response

Florida is typically a summer-peaking state, meaning that the summer peak demand generally controls the amount of generation required. While winter peak demands tend to be greater than summer, the higher peak is offset by the increased winter rating of power plants, which can take advantage of lower ambient air and water temperatures to produce more electricity from the same generating unit. During summer peak demand, higher temperatures instead can decrease generation, as high water temperatures may reduce not only the quality, but quantity of cooling water available based on environmental permits.

As with daily load, there is a great variation in seasonal peak load. Figure 8 below illustrates this for 2012, showing daily peak demand as a percentage of the annual peak. As demonstrated in the figure, winter peaks tend to be shorter duration events, while Florida's summer season has longer periods of high peak demands. The periods between the seasonal peaks are referred to as "shoulder months," and utilities take advantage of these periods of relatively low demand to perform maintenance without impacting their ability to meet the daily peak demand.

Figure 8: Generating IOUs - 2012 Daily Peak as a Percent of Annual Peak Demand



Source: 2013 TYSP Utilities Data Response

In general, a major controlling factor to seasonal peak demand is short-term weather conditions. While utilities forecast annual peak demand based upon historic factors, customer counts, and normalized weather patterns, utilities also continuously monitor weather conditions in their service territory and prepare for any increases (or decreases) in customer demand. By closely monitoring the weather situation, utilities can fine tune maintenance schedules to ensure the highest unit availability during the utility's peak demand.

Impact of Electric Vehicles

The FPSC also continues to examine the effects of plug-in electric vehicles (EVs) on the electric grid. EVs include any vehicles that draw some or all of their energy from the electric grid, as opposed to hybrid electric vehicles which, while conserving some energy through the braking process, still rely entirely on gasoline or diesel for their energy.

At present, Florida Department of Highway Safety and Motor Vehicles (FHSMV) data indicates that there were approximately 3,818 plug-in EVs registered in Florida as of May 1, 2013, with an additional 861 low-speed vehicles (such as electric golf carts and other neighborhood electric vehicles) registered.[5] Since the FHSMV reports 18.8 million vehicles of all types registered in Florida as of August 2013, EVs are still only approximately 0.025 percent of that total. Table 2 shows the growth in the registrations of plug-in EVs since 2008, the year the first modern EV, the Tesla Roadster, was made available.

[5] FHSMV provides VIN data to Polk Consulting, who decode VINs in order to establish make and model. The numbers include all electric-only vehicles, as well as the Chevy Volt, a plug-in hybrid. The statistics do not differentiate clearly between other plug-in hybrid vehicles and gasoline-only hybrids, but these data should capture most of the plug-in vehicles registered in the state of Florida.

Table 2: State of Florida - Plug-in EVs Registered in Florida (2008 - 2013)

Vehicle Category	2008	2009	2010	2011	2012	2013*	Total
Plug-in EVs	1	37	31	465	1,868	1,416	**3,818**
Low-Speed Vehicles	237	176	92	121	137	98	**861**
Total	**238**	**213**	**123**	**586**	**2,005**	**1,514**	**4,679**

* Through May 1, 2013.

Source: Polk Consulting, FHSMV.

Table 3 shows TYSP utilities' projections of the number of EVs in their service territories through 2022. While these numbers are presently limited, utilities project them to rise sharply over the next ten years, to a total of 315,958 by 2022. Even if that figure is reached, however, it would still represent less than 2 percent of projected vehicle registrations in Florida in 2022.

Table 3: TYSP Utilities - Estimates of the Number of Plug-In EVs by Service Territory

	Utility							
Year	**FPL**	**DEF**	**TECO**	**GPC**	**JEA**	**OUC**	**TAL**	**Total**
2012	2,020	238	176	169	9	537	16	**3,165**
2013	5,006	1,054	NA	685	12	1,030	32	**7,819**
2014	9,669	2,361	NA	1,344	20	1,624	58	**15,076**
2015	16,413	4,045	NA	2,119	38	2,689	98	**25,402**
2016	25,490	6,274	NA	3,015	214	4,037	157	**39,187**
2017	39,461	9,500	NA	3,998	431	5,685	235	**59,310**
2018	53,896	13,816	NA	5,141	651	7,646	329	**67,663**
2019	72,139	19,337	NA	6,447	876	9,937	461	**109,197**
2020	107,352	26,204	NA	7,921	1,104	12,574	645	**155,800**
2021	159,439	34,576	NA	9,566	2,006	15,570	838	**221,995**
2022	236,695	45,184	NA	11,248	2,924	18,859	1,048	**315,958**

Source: TYSP Utilities Data Response.

Table 4 shows the total projected energy consumption of the TYSP utilities associated with EVs during the same time frame. While the additional consumption is quite modest at present, utilities project it growing to almost 2,000 GWh in 2022.

Table 4: TYSP Utilities - Estimates for EV Annual Energy Consumption (GWh)

Year	EV Contribution to Annual Energy Consumption (GWh)							
	FPL	DEF	TECO	GPC	JEA	OUC	TAL	Total
2012	13	1.3	NA	0.7	0.0	0.2	5	**20**
2013	31	5.2	NA	2.8	0.1	0.5	11	**51**
2014	62	10.7	NA	5.5	0.2	1.0	19	**98**
2015	110	16.8	NA	8.7	0.4	1.6	33	**171**
2016	173	23.7	NA	12.4	2.3	2.4	53	**267**
2017	261	32.2	NA	16.4	4.8	3.4	79	**397**
2018	358	43.6	NA	21.1	7.6	4.6	111	**546**
2019	480	58.0	NA	26.5	10.8	6.0	155	**736**
2020	688	75.7	NA	32.5	14.2	7.5	218	**1,036**
2021	984	97.0	NA	39.3	26.9	9.3	283	**1,440**
2022	1,408	122.8	NA	46.2	40.9	11.3	354	**1,983**

Sources: TYSP Utilities Data Response

The effect these additional EVs will have on peak system demand is more difficult to determine. Due to numerous uncertainties regarding EV deployment, including at what times they will be charged and the possibility that EV charging may be shifted away from peak if necessary, most TYSP utilities were unable to project EVs effects at system peak. TYSP utilities did not report any current reliability or safety issues resulting from EVs, nor any needed system upgrades necessitated by EV deployment. As EV deployment moves forward, the effects of EVs on system peak should become clearer.

Demand Side Management

The first step in any resource planning process is to focus on the efficient use of electricity by consumers. Government mandates, such as building codes and appliance efficiency standards, provide the starting point for increasing energy efficiency. Customer choice is the next step in reducing the state's dependence upon expensive fuels and lowering greenhouse gas emissions. Consequently, educating consumers to make smart energy choices is particularly important. Finally, Florida's utilities can efficiently serve their customers by offering DSM and conservation programs designed to use fewer resources at lower cost.

Florida Energy Efficiency and Conservation Act

The Florida Legislature directed the Commission to encourage utilities to decrease the growth in seasonal peak demand and energy consumption in Sections 366.80 through 366.85 and Section 403.519, F.S., known as the Florida Energy Efficiency and Conservation Act (FEECA). Under FEECA, the Commission is required to set goals for demand and energy reduction for 7 electric utilities, namely the 5 investor-owned electric utilities (including Florida Public Utility

Company, which is a non-generating utility and therefore does not file a TYSP) and 2 municipal electric utilities (JEA and OUC).[6] These utilities represent 86 percent of sales in Florida.

The seven FEECA utilities currently offer DSM programs to residential, commercial, and industrial programs. Energy audit programs provide a first step for utilities and customers to evaluate conservation opportunities and serve as the foundation for other programs.

The last annual demand and energy goal-setting proceeding was completed in December of 2009, providing annual goals for the period of 2010 through 2020. To meet the requirement to set goals at least once every five years, the Commission must establish annual goals for the 2015 through 2025 period by the end of 2014. The Commission already established dockets for each of the seven FEECA Utilities in July 2013, with hearing dates set for July 2014, and a final decision by the Commission expected by October 2014.

Demand Side Management Programs

DSM Programs generally fall into three categories: interruptible or curtailable load (IL), load management (LM), and conservation. The first two are generally considered dispatchable, and are referred to as Demand Response (DR), meaning that the utility can call upon them during a period of peak demand, but otherwise they are not in active use. In contrast, conservation measures are considered passive and are always working to reduce customer demand and energy consumption.

Interruptible or curtailable load is achieved through the use of agreements with large customers to allow the utility to interrupt selected portions of the customer's load during periods of peak demand. Interrupted or curtailed customers could make up for this generation by reducing their own industrial processes or by activating back-up generation. In exchange for the ability to reduce their electrical load, the utility usually offers such customers a discounted rate for energy or other credits which are paid for by all customers.

Load management programs involve the installation of a device that can interrupt a customer's appliance(s) for a short duration during a period of peak demand. These interruptions tend to have less notice than those provided to interruptible customers, and generally do not fully disconnect customers, but interrupt an individual appliance. Normally, interruptions are kept to short periods and are cycled between groups of customers. Due to the nature of the program, certain devices would be more appropriate to handle different seasonal demands. For example, air conditioning units would be interrupted to reduce a summer peak, while water heaters being interrupted may contribute more towards reducing a winter peak. As of 2013, over 3,145 MW of interruptible load and load management is available for summer peak, and is anticipated to expand to 3,618 MW by 2022.

In addition to active measures, customer-based conservation measures can have an impact on peak demand without requiring activation by the utility. These passive conservation measures typically involve improving a home or business' building envelope, such as greater insulation and energy-efficient windows, or installing more efficient appliances. These energy efficiency improvements decrease the customer's load at all times without requiring an

[6] Sections 366.82(1)(a), F.S.

interruption or reduction in service, and also have an impact on annual energy consumption. As of 2013, over 3,592 MW of cumulative conservation for summer peak demand has been installed, increasing to 5,009 MW by summer of 2022.

Projected Peak Demand & Energy Usage

Based on all of the factors and considerations above, Figure 9 below illustrates the historic and projected seasonal peak demand and annual energy consumption for the state of Florida. While seasonal peak demand is the instantaneous usage of a customer on the system, annual energy consumption addresses the total cumulative demand on the system over time, which determines the type of units required and the resulting amount of fuel consumed.

For each category the impacts of conservation (including some self-service generators), and for seasonal peak demand, load management programs, and interruptible/curtailable load is shown. The total demand or total energy for load represents what otherwise would be served if not for the impact of demand response and conservation programs. The net firm demand or net energy for load represents the anticipated final demand or energy value, and is used as a planning number for the calculation of generating reserves.

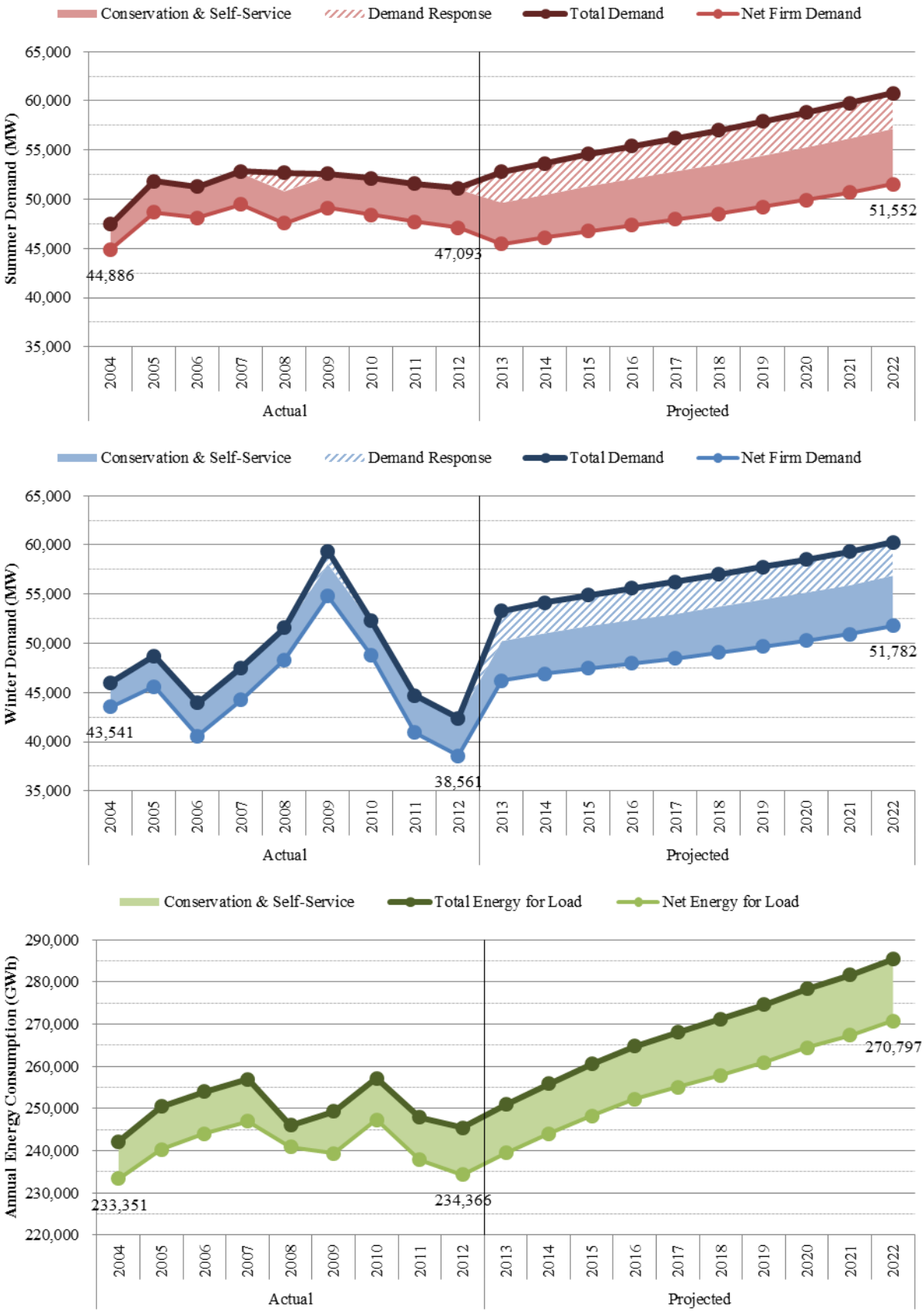
For historic values of seasonal peak demand, the actual rates of activation for interruptible/curtailable load and load management are shown. The amount of available demand response exceeded the activated amount shown, but was not called upon due to sufficient generation assets being available during the peak hour. Generally, residential load management programs have been called upon to a limited degree during peak periods, with a lesser amount of interruptible/curtailable load and commercial/industrial load management activated. The summer of 2008 and winter of 2009 are exceptions to this trend, when a larger portion of the available demand response resources were called upon.

For forecasted values of seasonal peak demand, it is assumed that demand response will be activated during the peak period. However, if companies have sufficient generating assets and it is economical to serve all customer load, demand response resources may not be activated or only partially activated based upon each utility's future operating conditions.

It should be noted that the forecasts shown are based upon normalized weather conditions, while historic demand and energy forecasts represent the actual impact of severe or mild weather conditions on Florida's electric customers. Florida relies heavily upon both air conditioning in summer and electric heating in winter, so both seasons experience a great deal of variability.

While Figure 9 shows historic and forecasted winter peak demand values as the highest seasonal values, summer peak dominates planning for most TYSP Utilities because most generating units are sensitive to ambient temperature and are able to generate more in the winter than in the summer. This is illustrated later in the determination of the generating reserve margin.

Figure 9: State of Florida - Seasonal Peak Demand and Annual Energy Consumption (Historic & Forecast)



Source: 2013 FRCC Regional Load & Resource Plan

Accuracy of Energy Forecasts

For each utility filing a TYSP, the Commission reviewed the historical forecast accuracy of past retail energy sales forecasts. The review compared actual retail energy sales for each year to energy sales forecasts made three, four, and five years prior. For example, the actual 2012 energy sales were compared to the projected 2012 value from forecasts made in 2009, 2008, and 2007. These differences, expressed as a percentage error rate, were used to calculate the utility's historical forecast accuracy using a five year rolling average. For example, the 2012 error rate looks at the difference between actual retail energy sales for 2012 through 2008, drawing upon projections made between 2009 through 2003. An average error with a negative value indicates a tendency to under-forecast, while a positive value represents an over-forecasting of retail energy sales. Absolute average error provides an indication of the total magnitude of error, regardless of the tendency to under/over-forecast.

Table 5: TYSP Utilities - Accuracy of Retail Energy Sales Forecasts

TYSP Year	Five Year Period	Forecast Error (%)	
		Average	Absolute Average
2009	2008 - 2004	1.79%	3.56%
2010	2009 - 2005	5.01%	5.71%
2011	2010 - 2006	8.31%	8.31%
2012	2011 - 2007	11.91%	11.91%
2013	2012 - 2008	15.10%	15.10%

Source: 2004 - 2013 TYSPs

Table 5 above illustrates the historical forecast error for the combined 2013 through 2009 TYSPs. These correspond to actual data from 2012 through 2008. Overall, a pattern of increasing error in retail sales forecasts is shown, with error over 10 percent based in 2011 and 2012. The high error rate, which has increased each year for the past five years, seems to be associated with the unexpected impacts of the recession on retail energy sales in Florida, both from reduction in the state's growth rate, but also from decreased usage per capita. As the five year rolling average progresses and includes more years post-recession, the error values should subside.

Table 6 below provides a more detailed data set used to calculate the average error rating, showing forecasts made between one and six years prior. A significant increase in error is evident in 2008 and beyond, with forecasts made post 2009 improving in accuracy and approaching historic levels of error. As this analysis moves forward and begins to use forecasts developed after the beginning of the recession, the error rate should fall back to typical levels.

Table 6: TYSP Utilities - Accuracy of Retail Energy Sales Forecasts - Annual Analysis

Year	Years Prior						Average Error	Absolute Average Error
	6	5	4	3	2	1		
2004	-	-4.96%	-3.06%	0.31%	-0.47%	1.05%	**-2.57%**	**2.78%**
2005	-5.79%	-4.00%	-0.66%	-0.60%	0.75%	0.93%	**-1.75%**	**1.75%**
2006	-3.24%	0.02%	1.08%	2.35%	2.48%	2.42%	**1.15%**	**1.15%**
2007	0.61%	2.31%	3.54%	3.63%	4.25%	3.09%	**3.16%**	**3.16%**
2008	7.02%	8.40%	8.55%	9.97%	9.24%	8.34%	**8.97%**	**8.97%**
2009	11.97%	12.17%	14.50%	13.93%	12.70%	10.19%	**13.53%**	**13.53%**
2010	12.94%	15.58%	14.89%	13.70%	10.56%	-0.73%	**14.72%**	**14.72%**
2011	21.39%	20.63%	19.92%	16.86%	3.65%	-0.06%	**19.14%**	**19.14%**
2012	26.30%	25.97%	23.03%	8.47%	3.90%	3.70%	**19.15%**	**19.15%**

Source: 2004 - 2013 TYSPs

As indicated by this high error rate, utilities projected increased need for energy that has not materialized due to the recession. The TYSP utilities have responded to changing circumstances by delaying or cancelling new generation and taking opportunities to modernize existing plants, as discussed in previous annual reviews of the TYSPs.

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)(b), 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 1,470 MW of firm and non-firm generation capacity, which represents 2.2 percent of Florida's overall generation capacity of 58,200 MW in 2012.[7] Table 7 below summarizes Florida's existing renewable energy sources.

Table 7: State of Florida - Existing Renewable Resources

Renewable Fuel Type	Summer Net Capacity (MW)
Land Fill Gas	40
Municipal Solid Waste	466
Biomass	415
Solar	178
Hydro	63
Waste Heat	308
Wind	0
Total	**1,470**

Source: 2013 FRCC Regional Load & Resource Plan, TYSP Utilities Data Responses

[7] Total MW capacities are based off summer ratings.

Renewable Generation

Of the total 1,470 MW of renewable generation, approximately 434 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.

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 84 percent, comes from non-utility generators. In 1978 the U.S. 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. Section 366.051, F.S., provides:

> 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 25-17.230, 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 to select the payment option that best fits its financing requirements and provides a basis from which negotiated contracts can be developed. On June 25, 2013, the Commission approved standard offer contracts resulting in the continuous offering of nearly 3,700 MW for Florida's four largest IOUs.

As previously discussed a large amount 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.

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 is considered non-firm for planning purposes.

Renewable Generation

A significant portion of the utility owned renewable generation is from three solar energy facilities, totaling 110 MW, operated by FPL. The three solar projects, 2 solar PV facilities and 1 solar thermal facility, were approved for cost recovery pursuant to Section 366.92, F.S. which has since been revised, but previously stated:

> 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 generation, up to a total of 110 megawatts statewide.

In 2008, the Commission approved a petition by FPL seeking eligibility for cost recovery pursuant to the referenced Statute. At the time of its filing, FPL estimated that the three solar facilities would cost an additional $573 million above traditional generation costs over the life of the facilities. Based on actual data provided by FPL, the combined cost of generation of the three solar facilities was $.45/kWh in 2012.

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. Based on actual data collected from the three facilities, the output does not appear to be coincident with the system's peak demand.

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. Because of Florida's geography, however, new hydroelectric power generation is largely limited.

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 the discussed Rule, customer owned renewable generation attributed 3 MW of renewable capacity. As of 2012, approximately 44 MW of renewable capacity from nearly 5,300 systems had been installed statewide. Table 8 below, summarizes the growth of customer owned renewable generation interconnections.

Table 8: Renewable Generation Interconnections

Year	2008	2009	2010	2011	2012
Facilities	577	1,625	2,833	3,994	5,296
MW	3	13	20	29	44

Source: Annual Net Metering Reports

Planned Renewable Additions

Florida's utilities plan to construct or purchase an additional 966 MW of renewable generation over the ten-year planning period. Table 9 summarizes the planned renewable capacity increases by generation type.

Table 9: State of Florida - Planned Renewable Resource Additions

Renewable Fuel Type	Summer Net Capacity (MW)
Land Fill Gas	12
Municipal Solid Waste	125
Biomass	470
Solar	359
Hydro	0
Waste Heat	0
Wind	0
Total	**966**

Source: 2013 FRCC Regional Load & Resource Plan, TYSP Utilities Data Response

Of the 966 MW of planned renewable capacity, 510 MW are projected to be from firm resources. All of the projected firm capacity additions are from renewable contracts with non-utility generators. Table 10 summarizes the firm capacity renewable resources that are planned over the ten-year horizon. The remaining planned capacity from renewable resources is projected to be from non-firm resources including several 50 MW solar facilities.

Table 10: State of Florida - List of Planned Renewable Firm Capacity

Purchasing Utility	Facility Name	Fuel Type	Capacity (MW)	In-Service Date
FPL	EcoGen Clay	OBS	60	2021
FPL	EcoGen Martin	OBS	60	2021
FPL	EcoGen Okeechobee	OBS	60	2021
FPL	Solid Waste Authority of Palm Beach #2	MSW	70	2016
GRU	Gainesville Renewable Energy Center	WDS	100	2014
DEF	FB Energy	AB	60	2013
DEF	Transworld Energy	WDS	40	2013
DEF	EcoGen Polk	WDS	60	2014
Total			**510**	

Source: TYSP Utilities Data Responses

More than 170 MWs of contracted firm renewable capacity are projected to expire within the ten-year planning. 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.

Renewable Outlook

The Commission, in conjunction with the U.S. Department of Energy and the Lawrence Berkeley National Laboratory, retained Navigant Consulting, Inc. (Navigant) to prepare a detailed assessment of Florida's renewable potential. Navigant's assessment identified several key drivers that impact renewable energy development in Florida. Three of the "key drivers" were the cost of natural gas, the cost of CO_2, and the adoption of a Renewable Portfolio Standard (RPS).

Under a scenario considered to be favorable in fostering renewable generation, Navigant assumed natural gas prices between $11-$14/MMBTU, CO_2 emission costs ($2/ton initially, then scaling to $50/ton by 2020) and the adoption of an RPS in Florida. At this time, natural gas prices are projected at $3.88/MMBTU in 2013, there is no current federal pricing for CO_2 emissions, and no RPS legislation has been enacted. Therefore, current market conditions do not favor the development of renewable generation.

Even with these difficulties, Florida's renewable generation is projected to increase over the planning period. Renewable generation contributes to the state's fuel diversity, as discussed in the next chapter, and reduces dependence upon fossil fuels. While current economic conditions may prevent more expensive forms of renewable generation, those cost-effective forms of renewable generation will continue to increase the state's share of renewable generation.

Traditional Generation

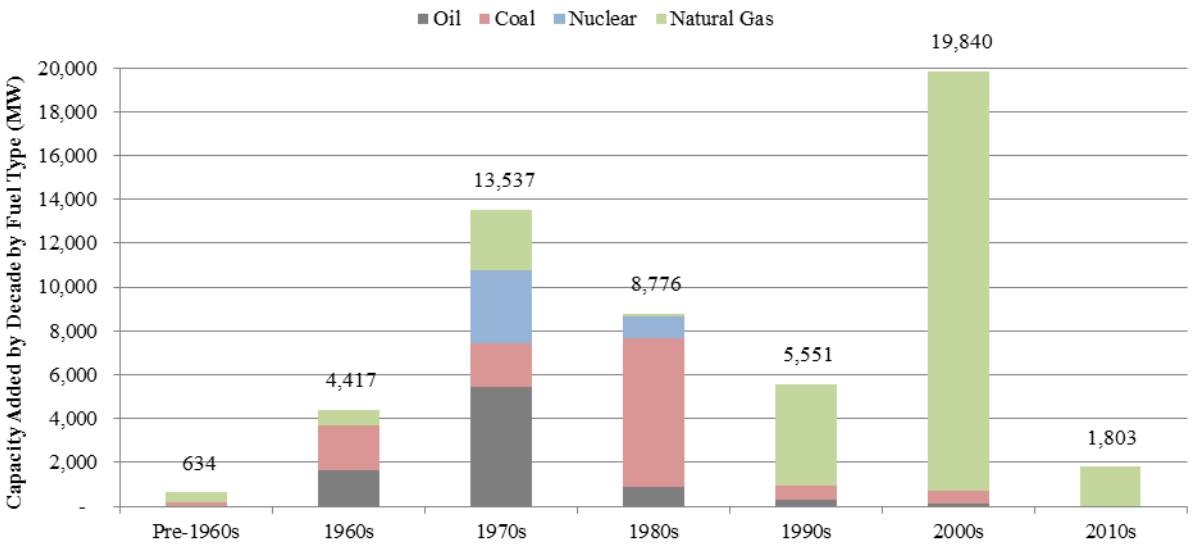
While renewable generators contribute to the state's generating capacity, a majority is made up of fossil-fueled steam and turbine generators that have been added to the grid over the last several decades. Due to forecasted increases in peak demand, further fossil-fired generation is anticipated over the planning horizon.

Historically, Florida's utilities relied upon oil-fired generation as the primary source of electricity until the increase in oil prices associated with the oil embargo. Since that time, Florida's utilities have sought a variety of other fuel sources to diversify the generating capacity and economically serve Florida's electric customers. Solid fuels, such as coal and nuclear, were utilized in greater quantity. Finally, natural gas has emerged as the dominant generating fuel. The swings of fuel prices, availability, environmental concerns, and other factors have resulted in a variety of capacity on Florida's existing system.

Existing Generation Resources

Florida's generating fleet includes incremental new additions to the 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 continue safe operation. Figure 10 below illustrates the decade currently operating generating capacity was originally added to the grid, with the largest additions occurring in the 2000s.

Figure 10: State of Florida - Generation Capacity Additions by Fuel Type and Decade



Source: 2013 FRCC Regional Load & Resource Plan

Traditional Generation

The existing generating fleet will be impacted by several events over the planning period. Retirements, including Crystal River 1 through 3 and Scholz 1 and 2, will reduce the existing fleet, while modernizations will replace older generation with newer, more efficient resources, and several units may have to install new pollution control equipment that may reduce net capacity. These items are discussed below.

Impact of EPA Regulations

In addition to maintaining a fuel efficient and diverse fleet, Florida's utilities must also comply with changing environmental requirements. During the past several years, the EPA has finalized or proposed several rules which will impact both existing and planned generating units in the state. Potential environmental requirements and their associated costs must be considered to fully evaluate any new supply-side resources, as well as the maintenance and dispatch of existing generating units.

Four EPA rules are anticipated to potentially affect electric generation in Florida:

- 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 gnerators, 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 28 states, including Florida, 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 these states. Florida is only subject to the rule's seasonal NOx emissions requirements. Due to ongoing litigation, the only costs utilities reported associated with CSAPR are stranded costs.

- 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 existing electric generators that use water for cooling with an intake velocity of at least two million gallons per day must meet impingement standards.

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

At this time, GPC's coal-fired Plant Scholz units 1 & 2 and DEF's Crystal River units 1 & 2 are the only plants anticipated to be retired as a result of any of these regulations. Additionally, DEF's Suwanee River Units 1-3, which can use either residual oil or natural gas, will cease residual oil operations in order to comply with the MATS rule. GPC has estimated that the costs for complying with the MATS Rule will make the operation of Plant Scholz uneconomical, and it will cease operation on April 1, 2015. Crystal River Units 1 and 2 are expected to cease operation in April of 2016, following a one-year MATS extension to perform transmission upgrades needed to take the units offline without affecting reliability.

For many of the plants that will remain in operation, these new rules will result in an increased cost of operations. Each utility will need to evaluate whether these additional costs or new 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. Several of the TYSP utilities have provided preliminary estimates based upon known and proposed rule language, and are shown in Table 11 below.

Table 11: TYSP Utilities - Cost Estimates of EPA Rule Compliance (2013-2022)

Utility	Preliminary Total Cost Estimates ($ Millions)				
	MATS	CSAPR	CWIS	CCR	Total
Florida Power & Light	$226	0	$122-$1,515	Unavailable	$348-$1,741
Duke Energy Florida (Capital Costs Only)	85-130*	0	80-1,200	Unavailable	165-1,330
Tampa Electric Company	18.6	0	860	$141**	1,020
Gulf Power Company	544-843	0	38-125	255-414	837-1,382
Florida Municipal Power Agency	Unavailable	Unavailable	Unavailable	Unavailable	Unavailable
Gainesville Regional Utilities	Unavailable	Unavailable	0	Unavailable	Unavailable
JEA	Unavailable	Unavailable	Unavailable	Unavailable	Unavailable
Lakeland Electric	Unavailable	Unavailable	Unavailable	Unavailable	Unavailable
Orlando Utilities Commission	2.3	$11	Unavailable	13	26
Seminole Electric Cooperative	0	0	Unavailable	Unavailable	0
City of Tallahassee	Unavailable	Unavailable	Unavailable	Unavailable	Unavailable
Total	**$876-$1,220**	**$11**	**$1,100-$3,700**	**$409-$568**	**$2,396-$5,499**

* Excludes costs related to Crystal River Units 1 and 2.

** Excludes Capital Costs.

Source: TYSP Utility Data Responses

Modernization and Efficiency Improvements

Recently, several of Florida's utilities have taken advantage of high reserve margins and engaged in modernizations of existing plant sites. These projects involve removing existing generator units that may not be as economical to operate, such as oil-fired steam units, and reusing the 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 price lower than new construction.

The Commission has previously granted determinations of need for several conversions of oil-fired steam to natural gas-fired combined cycle units, including FPL's Cape Canaveral, Riviera, and Port Everglades sites. The Commission has also granted determinations of need for conversion of existing combustion turbines into combined cycle units, including the conversion of TECO's Polk Units 2 through 5 in 2012. DEF has also recently conducted a conversion of its Bartow plant, but this did not require a determination of need from the Commission.

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 investigated before considering new construction. Utilities should continue to explore potential conversion projects and report the feasibility and economic viability of each conversion in next year's TYSPs and before any need determination filing.

For some existing units, generation output can be improved by installing more advanced equipment. The Commission has previously granted determinations of need for uprates at existing nuclear units, resulting in an additional 440 MW in new capacity. FPL also plans improvements in several of its combined cycle generating units by upgrading the integrated combustion turbines.

Planned Retirements

This year's update of the utility's TYSPs includes a large number of retirements. The most notable of these is DEF's announcement of the retirement of Crystal River Unit 3 (CR3), one of only five nuclear plants within the state of Florida. CR3 had been offline for several years due to complications from a steam generator replacement project meant to expand the life of the unit beyond its initial 40 year planned life. As a going forward concern, this retirement reduces the fuel diversity of the existing generation fleet, further increasing dependence on natural gas which has served as the primary replacement fuel.

Table 12 below lists all planned retirements by TYSP Utilities of existing generating units over the planning period, totaling 4,144 MW, a majority of which is oil-fired steam generation. These is due to a combination of factors, with specific units retired due to the modernization of existing plants, the proposed EPA Rules discussed above, or the generating unit reaching the end of its design life.

Table 12: TYSP Utilities - Planned Unit Retirements

Utility	Generating Unit Name	Generator Type	Summer Capacity (MW)	Planned Retirement Date*	Notes
Nuclear Units					
DEF**	Crystal River 3	Nuclear Steam	850	01/2013	
Oil-Fired Units					
FPL	Port Everglades 3 & 4	Oil Steam	761	01/2013	Modernization
FPL	Turkey Point 1 & 2	Oil Steam	788	01/2013*	
DEF	Suwannee River 1 - 3	Oil Steam	129	06/2018	
DEF	Various	Oil Turbine	56	04/2016	
Coal-Fired Units					
DEF	Crystal River 1 & 2	Coal Steam	869	04/2016	EPA Rules Related
GPC	Scholz 1 & 2	Coal Steam	92	04/2015	EPA Rules Related
Gas-Fired Units					
FPL	Municipal Plant 2 & 5	Gas CC	44	01/2017	
FPL	Municipal Plant 1, 3, 4	Gas Steam	94	01/2014	
DEF	Various	Gas Turbine	129	06/2016	
GPC	Pea Ridge 1-3	Gas Turbine	12	12/2018	
GRU	Various	Gas Steam	98	10/2015*	
GRU	JR Kelly GT01-03	Gas Turbine	42	02/2018*	
TAL	Various	Gas Turbine	56	03/2015*	
TAL	Various	Gas Steam	124	12/2013*	
Total			**4,144**		

*Planned Retirement Date is for earliest unit retirement. Other units may retire later than indicated here
** Multiple Joint Owners for Crystal River 3. Primary owner listed here.

Source: 2013 TYSPs, 2013 FRCC Regional Load & Resource Plan

Reserve Margin Requirements

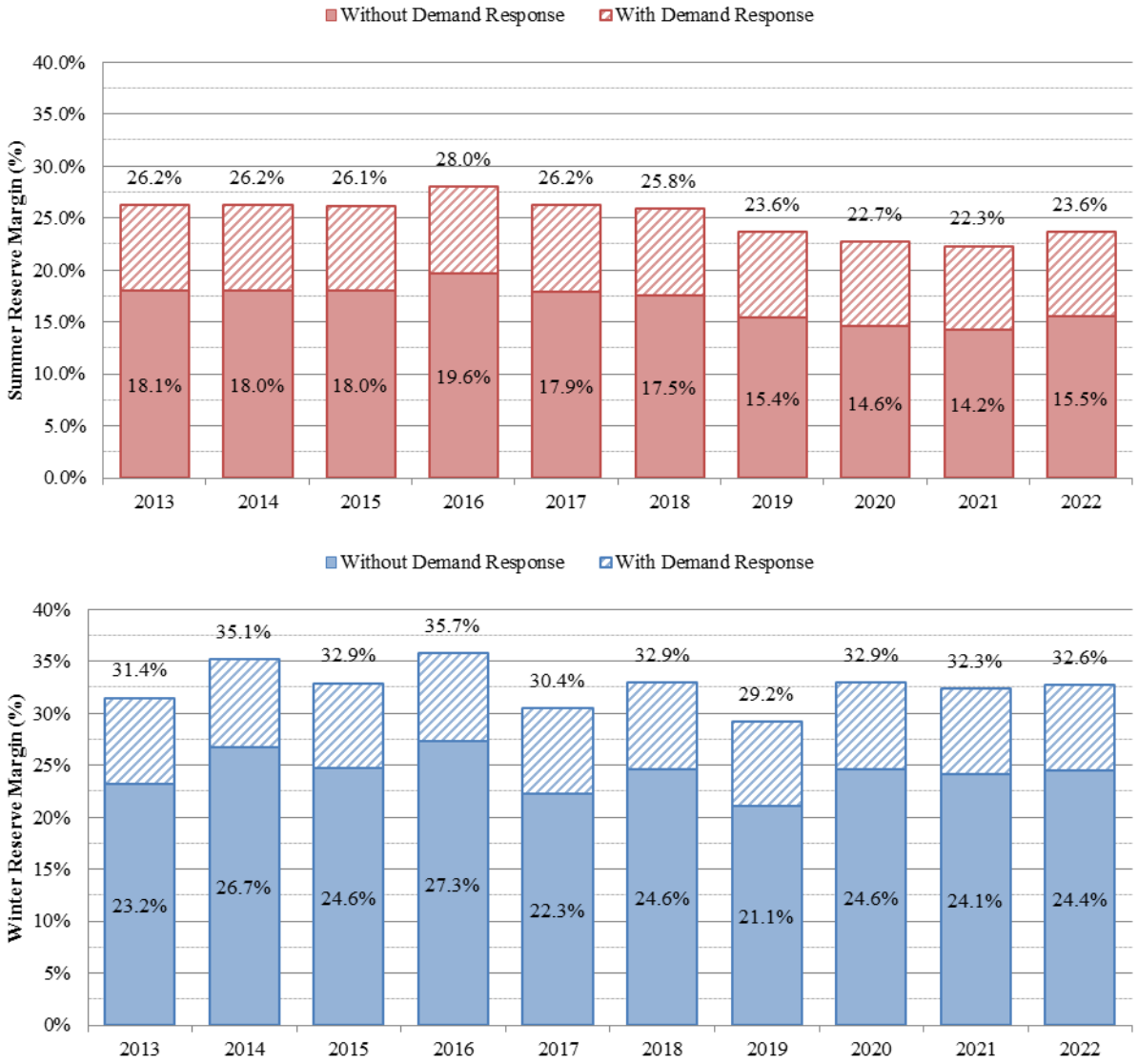
In order to maintain stability in the electric system, utilities must constantly adjust system output to match demand from moment to moment. As demand fluctuates, utilities must generate the precise amount of electrical power that will keep the system in balance while also performing periodic maintenance on its generating units. In addition, utilities must be prepared at any moment to meet unforeseen circumstances, such as extreme weather events or unit outages. Therefore, each utility must maintain a certain amount of "extra" or reserve capacity in the event that demand rises above or supply drops below forecasted levels. This additional amount of generating capacity is expressed as a percentage of firm demand and is referred to as the reserve margin.

Reserve margins in Florida typically remain well above the FRCC minimum of 15 percent for most of the year, and usually will only approach minimum levels in the summer peak season when air conditioning loads are at their highest levels. The higher margins during winter peak seasons are also due to the fact that generating units can operate at a higher capacity in colder temperatures. The three largest IOUs, FPL, DEF, and TECO, were party to a stipulation approved by the Commission setting a 20 percent reserve margin planning criterion.

The values in Figure 11 below include both supply-side and demand-side contributions, and shows that planning is mostly controlled by summer peak demand. It should be noted that

the figure below is for the State of Florida, and therefore contains generating capacity outside of the FRCC region.

Figure 11: State of Florida - Seasonal Reserve Margin (Summer & Winter)



Source: 2013 FRCC Regional Load & Resource Plan

Role of Demand Side Management in Reserve Margin

It should be noted that the reserve margin figures above are calculated using the net firm system demand for the diagonal shaded value, which assumes full use of interruptible load and load management devices to reduce peak demand, while the total system demand, which only includes generation and conservation, is the solid value. Participation in interruptible rates and load management programs are voluntary, for which incentives are provided in the form of lower rates or credits paid to the participant. As shown in Figure 11 above, the state as a whole has

sufficient generation capacity planned throughout a majority of the period to meet the minimum reserve margin of 15 percent without relying on demand response. As noted previously, these customers have not typically been activated during periods of peak demand.

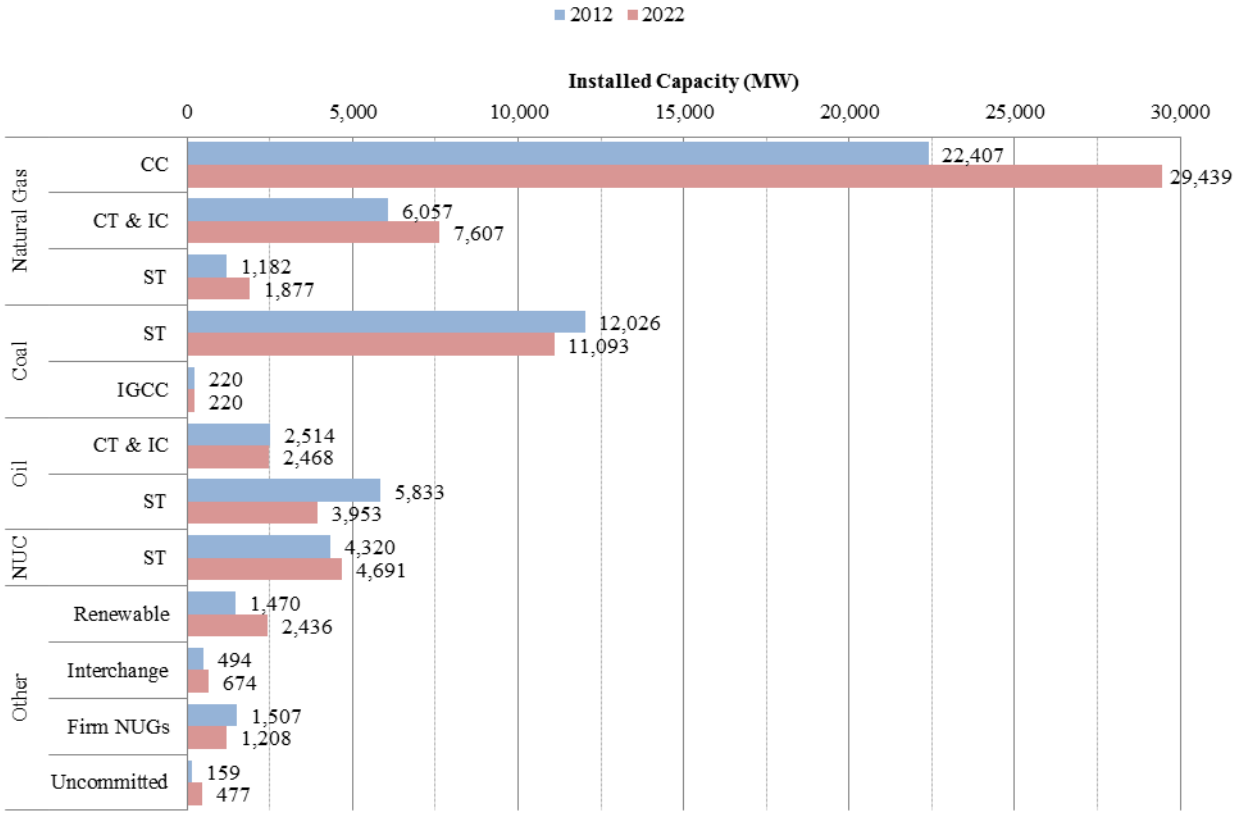
New Generation Resources

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 traditional generating capacity still exists. While reductions in demand have been significant, the total demand for electricity and the per-capita consumption 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.

Figure 12 below illustrates the present and future aggregate capacity mix. The capacity values in Figure 12 incorporate all proposed additions, changes, and retirements contained in the reporting utilities' 2013 Ten-Year Site Plans.

Figure 12: State of Florida - Installed Capacity (Existing & Projected)



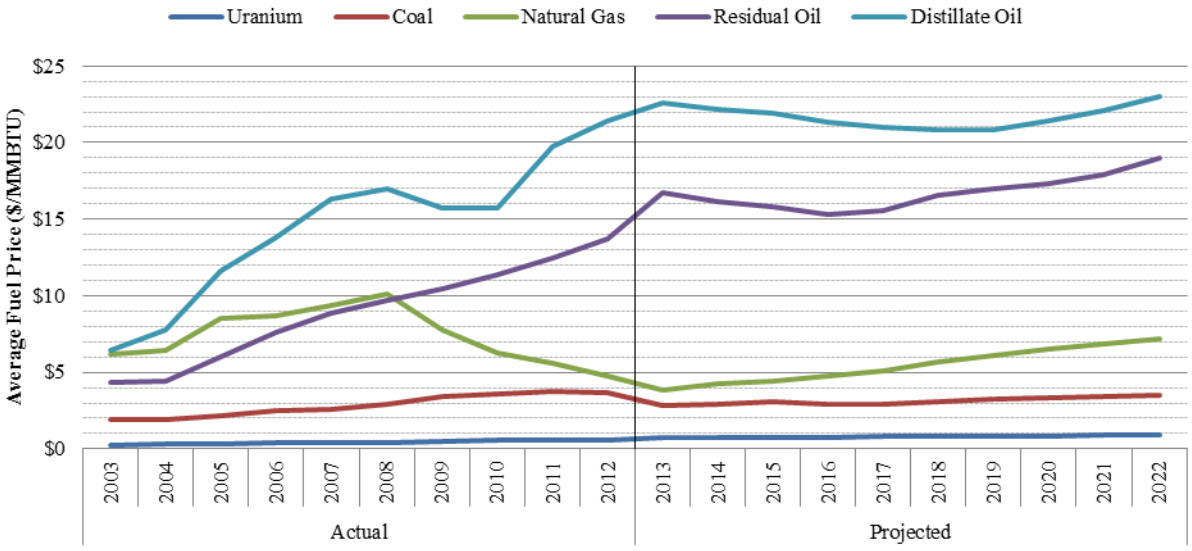
Source: 2013 TYSPs, 2013 FRCC Regional Load & Resource Plan, 2013 TYSP Utilities Data Responses

Fuel Price Forecasts

Fuel price forecast is the primary factor affecting the type of generating unit added by an electric utility. In general, the capital cost of a generating unit is inversely proportional to the cost of the fuel used to generate electricity from that unit. Historically, when the forecasted price difference between coal or nuclear and natural gas was small, the addition of a natural gas unit became the more attractive option. As the fuel price gap widened, a coal-fired or nuclear unit would normally be the more likely choice.

From 2003 to 2005, the price of natural gas was substantially higher than utilities had forecasted. This disparity led to concern regarding escalating customer bills and an expectation that natural gas prices would continue to be high and extremely volatile. As a result, Florida's utilities began making plans to build coal-fired units rather than continuing to increase the reliance on natural gas. Due to concerns regarding potential future environmental regulations and other projected costs, coal-fired generation was not selected. However, as Figure 13 shows, the price of natural gas began to return to more historic levels after peaking in 2008, and has declined in the years since. Forecasts predict that gas prices will increase at a steady rate throughout the planning horizon. This trend has encouraged utilities to switch units to be capable of burning natural gas, either as a starter fuel, supplemental fuel, or the primary fuel by changing the fuel type of a generating unit entirely.

Figure 13: TYSP Utilities - Fuel Prices (History & Forecast)

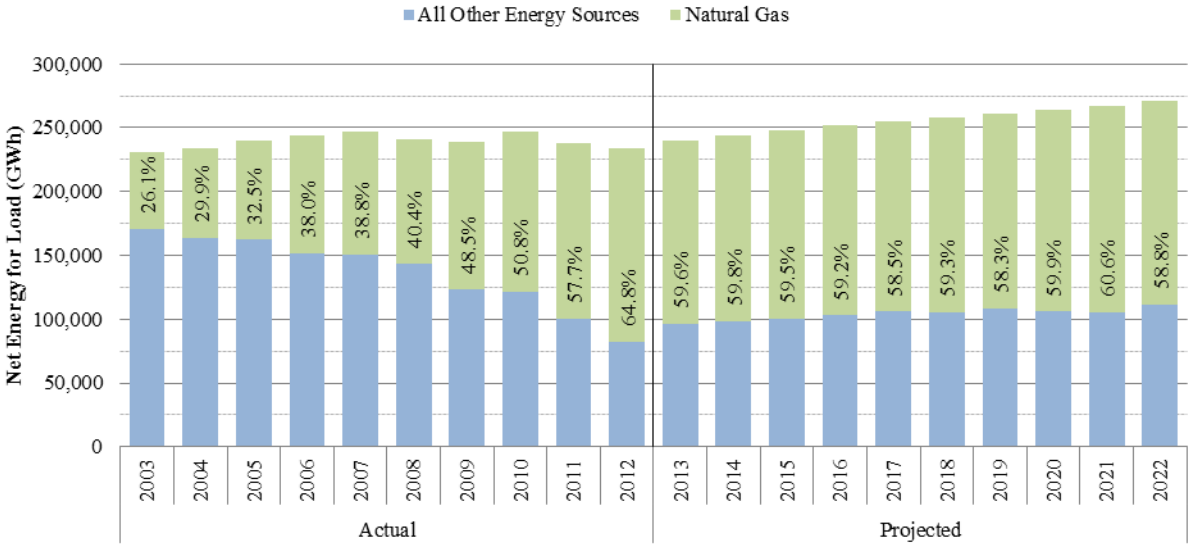


Source: TYSP Utilities Data Responses

Fuel Diversity

Natural gas has risen to become one of the dominant fuels in the state in the last ten years, displacing coal, and in 2012 generated more net energy for load than all other fuels combined in Florida. As Figure 14 shows, natural gas now makes up greater than 64.8 percent of electric energy consumed in Florida. Natural gas usage is anticipated to decline somewhat, remaining at approximately 60 percent throughout the planning period, ending up at 58.8 percent by 2022.

Figure 14: State of Florida - Natural Gas Usage (History & Forecast)



Source: 2013 FRCC Regional Load & Resource Plan

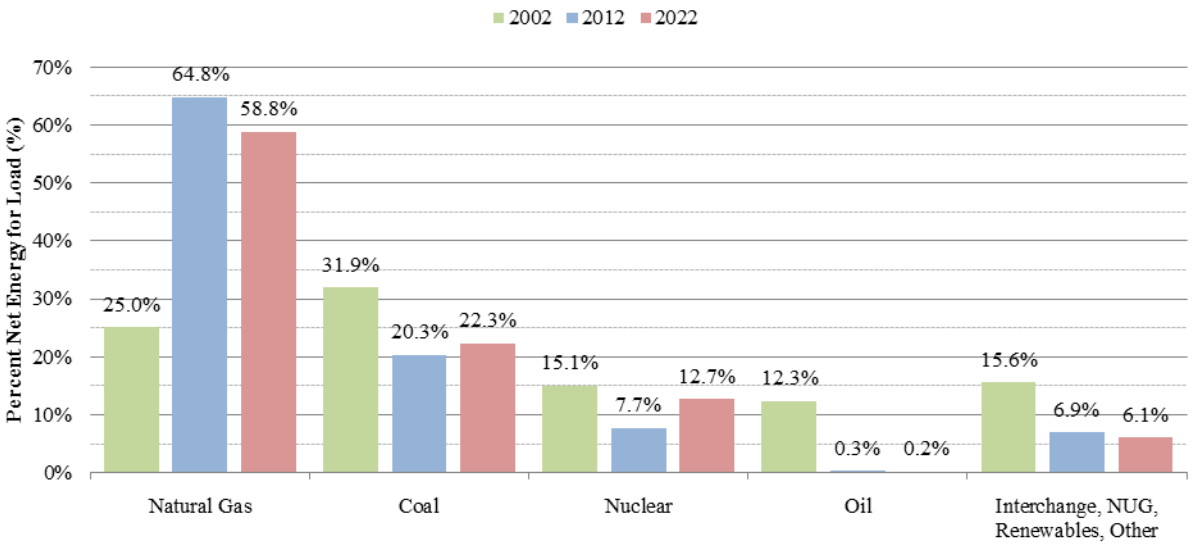
Traditional Generation

Combustion turbine technology is more efficient when used in a combined cycle mode, in which waste heat is recovered to generate steam, than steam generation alone. This gives natural gas a technological edge above its normal fuel price, so less fuel is required per unit of electricity generated. Because of this, despite coal having a lower price per unit energy, it is typically dispatched after natural gas based on current and projected fuel prices. As this gap widens again towards the end of the period, some increases in coal-fired generation are anticipated.

Utility plans for a balanced fuel system have historically been highly dependent upon the accuracy of long-term fuel price forecasts, mostly due to the long lead times required for coal and especially nuclear generators. However, in recent years the options available to utilities for the addition of supply-side generation have been limited, and this situation seems unlikely to change at this time. Utilities will be faced with selecting technologies for new generation that will either continue to increase the already very high percentage of natural gas resources, or attempting to obtain approval for solid fuel resources that may have a negative near term rate impact.

The anticipated decline in natural gas consumption over the planning period is the result of increased nuclear generation from FPL's uprates, which had many of their units off-line in 2012, and a slight increase in contribution to NEL from coal-fired generation. Nuclear generation is anticipated to increase at the end of the planning period, with the addition of Turkey Point 6 in the middle of 2022, to be followed the next year, outside of this planning period, by Turkey Point 7 in 2023. Figure 15 below illustrates the anticipated contribution by natural gas, coal, nuclear, oil, and all other sources, including interchange, non-utility generators, and renewables.

Figure 15: State of Florida - Fuel Diversity (History & Forecast)



Source: 2004 & 2013 FRCC Regional Load & Resource Plan

Compared to other states, Florida's usage of natural gas for electric generation is high when compared to total natural gas usage. At the TYSP Workshop, the FRCC provided data

from the Energy Information Administration (EIA) that shows that in 2011 Florida used approximately 86 percent of natural gas consumed in the state for electric generation, the highest rate in the nation. Natural gas is typically not used in end-user heating, with a majority of Florida's residential heating from electrical generation.

Table 13: FRCC - Ten Largest States for Natural Gas Consumption (2011 Data)

State	Total Annual Natural Gas Consumption (Bcf)	Annual NG Consumption for Electric Generation (Bcf)	Total Annual Marketed Natural Gas Production (Bcf)	Total Miles of Natural Gas Pipeline	Total Storage Capacity (Bcf)
Texas	3,646	1,555	7,113	58,588	812
California	2,153	651	250	11,770	571
Louisiana	1,398	462	3,029	18,900	690
Florida	**1,218**	**1,050**	**15**	**4,971**	**0**
New York	1,217	427	31	5,018	246
Illinois	987	50	2	11,911	997
Pennsylvania	*963*	304	1,311	8,680	777
Ohio	*820*	93	79	7,670	580
Michigan	*776*	100	138	9,722	1,075
New Jersey	*661*	188	0	1,520	0
Total US	***24,385***	**7,884**	**24,036**	**305,954**	**8,849**
Florida as % of Total	***5.0%***	**13.3%**	**0.06%**	**1.6%**	**0%**

Source: FRCC 2013 TYSP Workshop Presentation

As shown above, Florida has very little production and no gas storage capacity, yet is the fourth largest overall consumer of natural gas. Because of geographic constraints, Florida will most likely continue to rely on out of state production and storage to satisfy the growing electric demands in the state.

Coal generation, beyond the reduction in dispatch due to the cost-competitiveness of natural gas as a baseload fuel, faces challenges relating to new environmental compliance requirements. As discussed above, new EPA regulations will potentially require installation of new environmental controls, which could lead to the retirement of units if it is deemed uneconomic to upgrade its emission control equipment.

Because a balanced fuel supply can enhance system reliability and mitigate the effects of volatile fuel price fluctuations, it is important that utilities have the greatest possible level of

flexibility in their generation fuel source mix. Although the Commission has cited the growing lack of fuel diversity within the State of Florida as a major strategic concern for the past several years, natural gas is anticipated to remain the dominant fuel over the planning horizon. Excluding renewables, all new generation facilities planned within the State of Florida over the ten-year period are natural gas-fired units.

Projected New Units by Fuel Type

In the last ten years, almost all capacity additions to Florida's electric system use natural gas as the primary fuel. Coal units that were planned have been cancelled, and a majority of new nuclear units that have been approved have been delayed beyond the planning horizon. Gas fired units have almost exclusively been selected in recent years due to higher thermal efficiencies, lower capital costs, short periods for permitting and construction, and sometimes the smaller land areas required. With the recent decrease in fuel prices due to unconventional natural gas production using hydraulic fracturing, natural gas is the favored fuel for all traditional generating units with the exception of new nuclear units.

Currently, other than approximately 966 MW of renewable generation and 1,220 MW in uprates and new nuclear units, all of the additional generation planned for the next ten years will use natural gas as a fuel source.

Nuclear

Nuclear capacity, while an alternative to natural gas-fired generation, is capital-intensive and requires a long lead time to construct. Florida's utilities project an expansion of nuclear power in the state through uprates at existing nuclear power plants, and the construction of two new nuclear units. Table 14 below shows new nuclear capacity anticipated in the planning period. The Commission previously approved uprates for all existing nuclear units in Florida. The only remaining uprate to be completed is FPL's Turkey Point Unit 4, completed earlier this year. FPL also projects the first of its two new nuclear generating units to come online within the planning period, Turkey Point Unit 6. The second unit is anticipated to be in-service by 2023. DEF's 2012 TYSP included the return to service of an uprated CR3 in 2014. DEF's 2013 TYSP reflects the fact that CR3 has been retired and will not return to service.

Table 14: TYSP Utilities - Nuclear Unit Additions

Utility	Generating Unit Name	Summer Capacity (MW)	Certification Dates		In-Service Date
			Need Approved (Commission)	PPSA Certified	
FPL	Turkey Point 4 Uprate	120	01/2008	10/2008	03/2013
FPL	Turkey Point 6	1,100	04/2008	*	06/2022
Total Nuclear Additions		**1,220**			
* This units have not yet received PPSA Certification					

Source: 2013 TYSPs

Pursuant to a multi-party stipulation, DEF has elected to discontinue construction of its Levy Nuclear Plants. DEF will, however, continue its efforts to obtain a combined operating license from the Nuclear Regulatory Commission for the Levy Nuclear Project.

Natural Gas

With the exception of the aforementioned renewable and nuclear capacity, all remaining new generation comes in the form of natural gas fired combustion turbines or combined cycle units. Natural gas-fired combined cycles represent the most abundant type of generating capacity in the State of Florida, making up approximately 38.5 percent of installed capacity in 2012. Combustion turbines run in simple cycle mode 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 system, they do not require siting under the PPSA. Table 15 below includes approximately 8,683 MW of natural gas-fired generation included in the 2013 TYSPs.

Table 15: TYSP Utilities - Natural Gas Unit Additions

Utility	Generating Unit Name	Summer Capacity (MW)	Certification Dates		In-Service Date
			Need Approved (Commission)	PPSA Certified	
Combined Cycle Units					
FPL	Cape Canaveral	1,210	09/2008	10/2009	06/2013
FPL	Riviera Beach	1,277	09/2008	11/2009	06/2014
FPL	Port Everglades	1,212	04/2012	03/2013	06/2016
DEF	Unnamed CC 1	1,189	*	*	06/2018
DEF	Unnamed CC 2	1,189	*	*	06/2020
TECO	Polk 2-5 CC Conversion	459	12/2012	*	01/2017
SEC	Unnamed CC 1	192	*	*	12/2020
SEC	Unnamed CC 2	192	*	*	12/2020
Combustion Turbine Units					
SEC	Unnamed CT 1	198	**	**	12/2019
TECO	Future CT	190	**	**	05/2020
TAL	Hopkins 5	46	**	**	05/2020
SEC	Unnamed CT 2 & 3	396	**	**	12/2020
SEC	Unnamed CT 4 - 7	792	**	**	12/2021
DEF	Unnamed CT	187	**	**	06/2022
Total Natural Gas Additions		**8,683**			

* These units have not yet received a Determination of Need and/or a PPSA Certification.
** These units are not regulated under the PPSA, and do not require a Determination of Need.

Source: TYSP Utilities Data Response

Power Plant Siting Act[8]

The Florida PSC is given exclusive jurisdiction by the Legislature, through the PPSA, to be the forum for determining the need for new electric power plants. Any proposed steam or solar generating unit of at least 75 MW requires certification under the Power Plant Siting Act.

Approximately 9,960 MW of new utility-owned generating units are planned to enter service over the next 10-year period, with 82 percent of that subject to the PPSA. A majority of

[8] Sections 403.501 through 403.518, F.S.

this portion new generation has already received a determination of need from the Commission. A total of 2,762 MW still requires certification, as shown in Table 16.

Table 16: State of Florida - Proposed Generation Requiring Commission Approval

Utility	Generating Unit Name	Summer Capacity (MW)	In-Service Date
DEF	Unnamed CC 1	1,189	06/2018
DEF	Unnamed CC 2	1,189	06/2020
SEC	Unnamed CC 1	192	12/2020
SEC	Unnamed CC 2	192	12/2020
Total Capacity		**2,762**	

Source: 2013 TYSPs

Transmission Capacity

As generation capacities increase, the transmission system must grow accordingly to maintain the capability of delivering the energy to the end user. 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 Transmission Line Siting Act (TLSA).[9] 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 for and the proposed starting and ending points for lines requiring TLSA certification. The Commission must issue a final order granting or denying a determination of need within 90 days of the petition filing. The proposed corridor route is determined by the DEP 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 the proposed line.

Table 17 below lists all proposed transmission lines in the 2013 TYSPs 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.

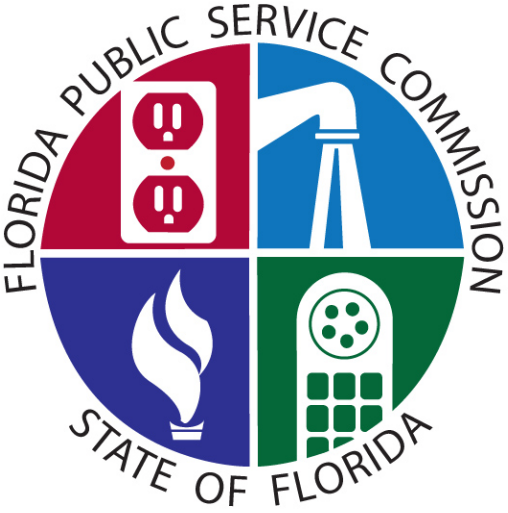
Table 17: TYSP Utilities - Transmission Requiring TLSA Approval

Utility	Transmission Line	Line Length (Miles)	Nominal Voltage (kV)	Certification Dates		Commercial In-Service Date
				Need Approved (Commission)	TLSA Certified	
DEF	Intercession City - Gifford	13	230	09/2007	01/2009	05/2013
FPL	Manatee - Bob White	30	230	08/2006	11/2008	12/2014
FPL	St. Johns - Pringle	25	230	05/2005	04/2006	12/2017

Source: TYSP Utilities Data Responses

[9] Sections 403.52 through 403.5365, F.S.

Utility Perspectives



FPL is the state's largest electric utility. The utility's service territory is within the FRCC region, and is primarily in southern Florida and along the east coast. As FPL is an IOU, the Commission has regulatory authority over all aspects of operations, including rates, reliability, and safety.

Load and Energy Forecast

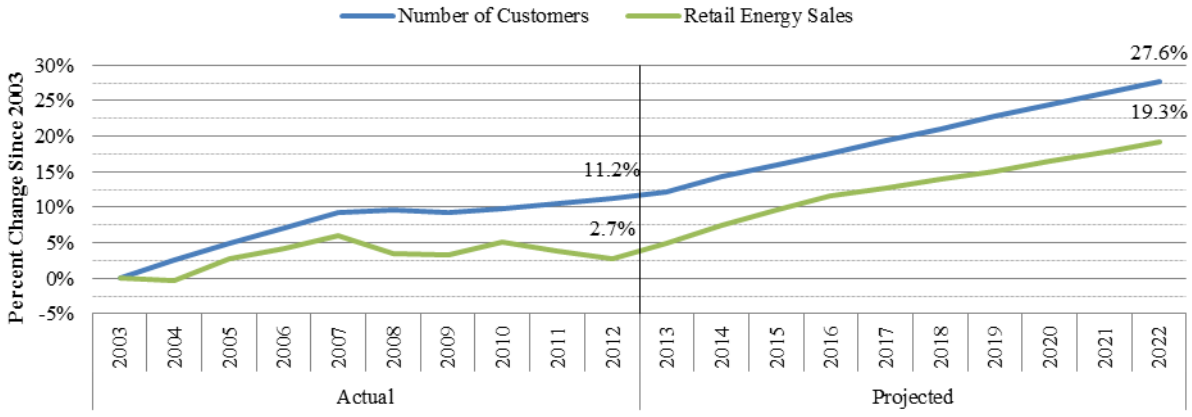
In 2012, FPL had approximately 4,572,800 customers, with annual retail energy sales of 101,678 GWh, or approximately 47.3 percent of the state of Florida's NEL. Total number of customers and annual energy consumption by customer class are below in Figure 16.

Figure 16: FPL - Number of Customers and Energy Usage by Class

Source: 2013 TYSP Schedule 2

Figure 17 illustrates the company's historic and projected growth as a percentage of its total number of customers and retail energy sales in 2003. Over the last ten years, FPL has increased/decreased its total number of customers by 11.2 percent, while increasing retail energy sales by 2.7 percent. The company forecasts continued positive growth for all years of the planning period, with retail energy sales exceeding the historic 2007 peak by 2014.

Figure 17: FPL - Customer and Retail Energy Sale Growth Since 2003



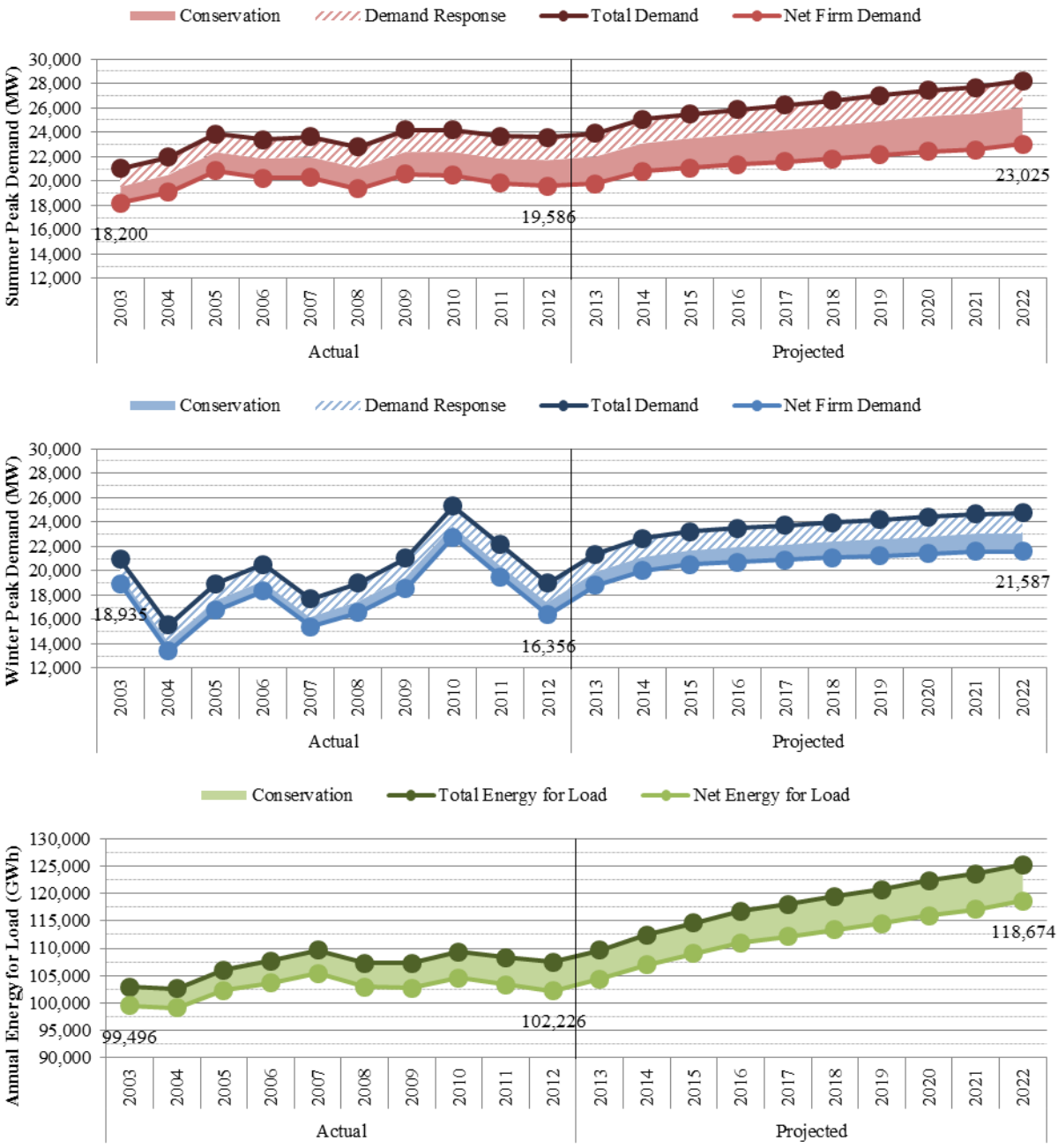
Source: 2013 TYSP Schedule 2

Florida Power & Light (FPL)

Seasonal Peak Demand & Annual Energy for Load

The following three graphs in Figure 18 show FPL's historic peak demand for both the summer and winter seasons, and net energy for load for the years 2003 through 2012. The forecasted values are also shown through the current planning horizon, including the effect of the utility's DSM programs. Available demand response values are shown below for the previous ten years, but demand response was not activated during the historic seasonal peak demand hours, excluding the winters of 2010 and 2011.

Figure 18: FPL - Seasonal Peak Demand and Annual Energy Consumption (Historic & Forecast)



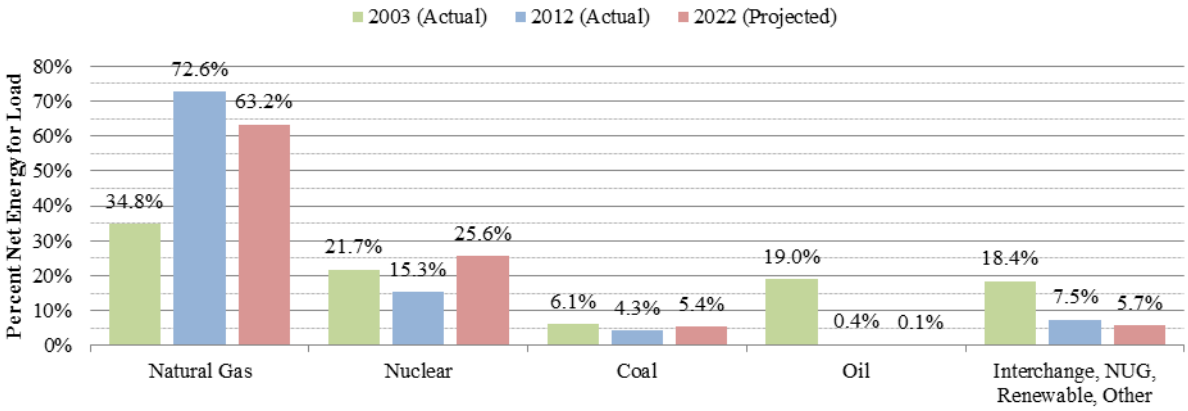
Source: 2013 TYSP Schedule 3

Generation Resources

Fuel Diversity

Figure 19 shows FPL's historic fuel mix for 2003 and 2012, and the projected fuel mix for 2022. FPL's primary generation fuel is natural gas, which has increased from 34.8 percent of system energy in 2003, to 72.6 percent in 2012. A portion of this increase is due to long-term outages of several nuclear units on FPL's system for uprates during 2012, with nuclear representing FPL's next highest fuel usage. The return to service of the uprated nuclear units will slightly decrease FPL's natural gas usage, estimated at 66.1 percent in 2013. The trend of natural gas being the primary system fuel will continue, with another decrease in usage, to 63.2 percent in 2022, due to an increase in nuclear generation with the addition of Turkey Point 6 for a portion of the year. Natural gas usage is anticipated to decline again in 2023 with a full year of operation of Turkey Point 6 and a partial year for Turkey Point 7.

Figure 19: FPL - Fuel Diversity (History & Forecast)



Source: 2013 TYSP Schedule 6

Planned Generation

FPL's 2013 TYSP includes five planned generation additions, including three combined cycle units, a nuclear uprate, and a new nuclear unit. A second new nuclear unit, Turkey Point 7, is planned in 2023, outside of the 2013 TYSP planning period. The planned units are detailed below in Table 18. This is consistent with the company's 2012 TYSP, featuring no new generating units. The previous TYSP also included the uprates completed in 2012 to FPL's other three nuclear units.

Table 18: FPL - Planned Generation Additions

Generating Unit Name	Generator Type	Summer Capacity (MW)	In-Service Date	PPSA
Natural Gas Units				
Cape Canaveral Energy Center	Combined Cycle	1,210	06/2013	Approved
Riviera Beach Energy Center	Combined Cycle	1,277	06/2014	Approved
Port Everglades Energy Center	Combined Cycle	1,212	06/2016	Approved
Nuclear Units				
Turkey Point Unit 4 Uprate	Steam Turbine	120*	03/2013	Approved
Turkey Point Unit 6	Steam Turbine	1,100	06/2022	Pending
Turkey Point Unit 7	Steam Turbine	1,100	12/2023	Pending

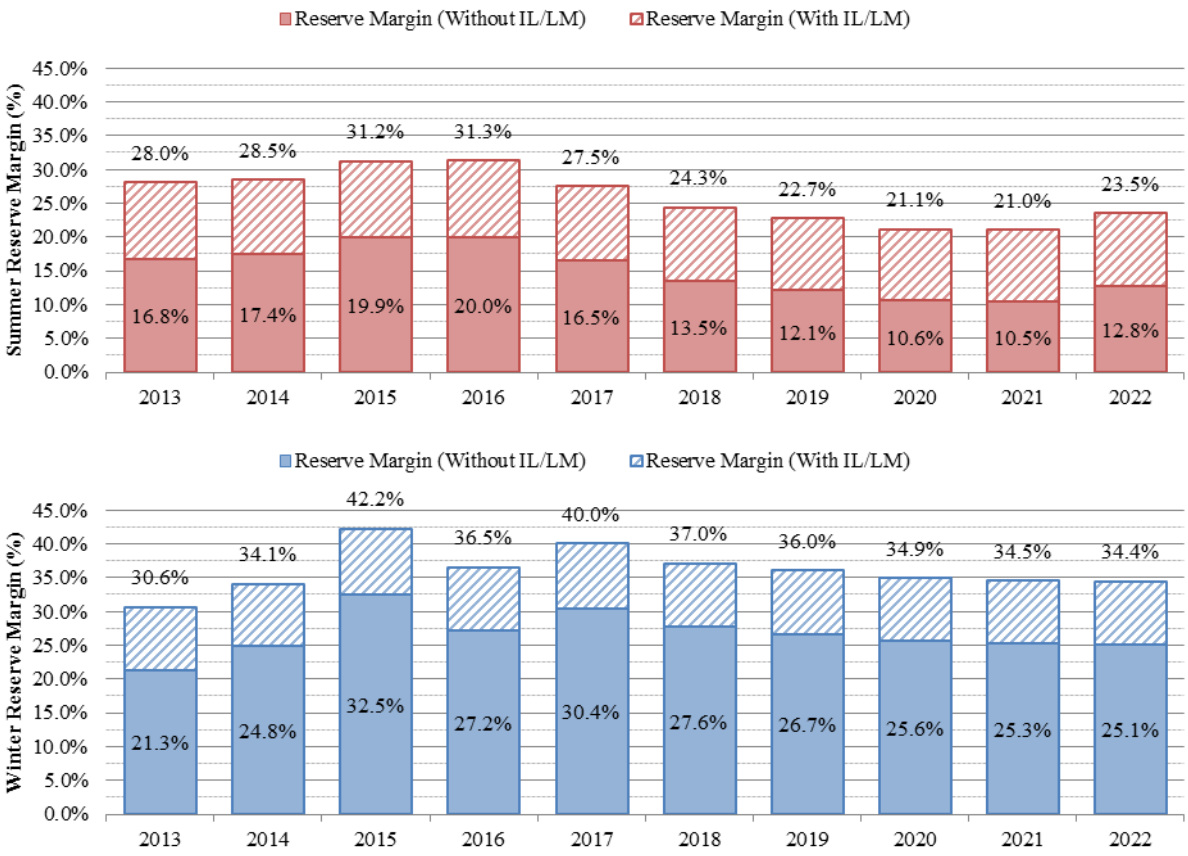
*This capacity represents the uprate only, not the full capacity of the generating unit

Source: 2013 TYSP Schedule 8

Reserve Margin

FPL maintains a minimum 20 percent reserve margin for planning purposes based on a stipulation approved by the Commission. Figure 20 displays the forecast planning reserve margin for FPL through the planning period for both seasons including the effects of projected conservation activities. The impact of demand response programs on reserve margin is also included. As shown in the figure, FPL is a summer peaking utility.

Figure 20: FPL - Seasonal Reserve Margin (Summer & Winter)



Source: 2013 TYSP Schedule 7

DEF is an investor-owned utility, and Florida's second largest TYSP utility. The utility's service territory is within the FRCC region, and is primarily located in central and west central Florida. The company's TYSP was filed under its previous business name, Progress Energy Florida, Inc. (PEF). As DEF is an IOU, the Commission has regulatory authority over all aspects of operations, including rates, reliability, and safety.

Load and Energy Forecast

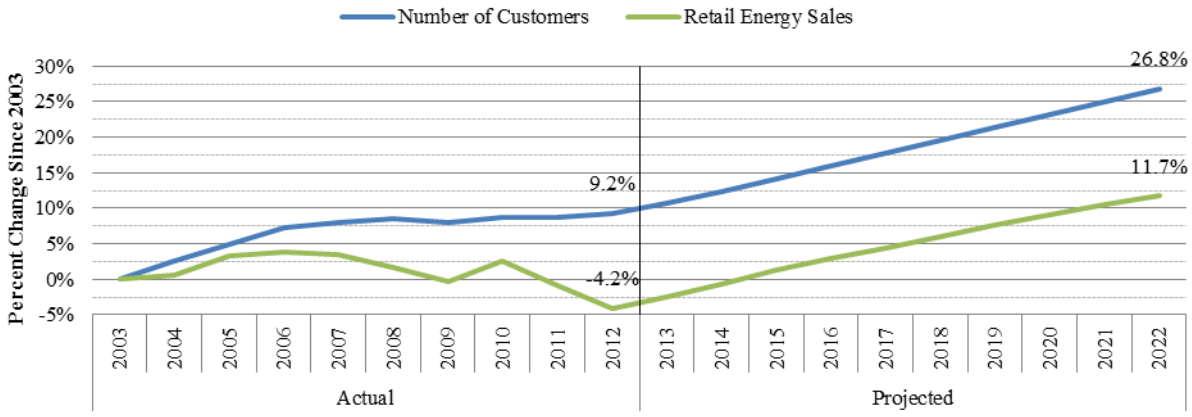
In 2012, DEF had approximately 1,624,400 customers, with annual retail energy sales of 33,135 GWh, or approximately 17.6 percent of the state of Florida's NEL. Total number of customers and annual energy consumption by customer class are below in Figure 21.

Figure 21: DEF - Number of Customers and Energy Usage by Class

Source: 2013 TYSP Schedule 2

Figure 22 illustrates the company's historic and projected growth as a percentage of its total number of customers and retail energy sales in 2003. Over the last ten years, DEF has increased its total number of customers by 9.2 percent, while retail energy sales have declined by 4.2 percent. The company forecasts positive growth for all years of the planning period, with retail energy sales exceeding the historic 2006 peak by 2017.

Figure 22: DEF - Customer and Retail Energy Sale Growth Since 2003



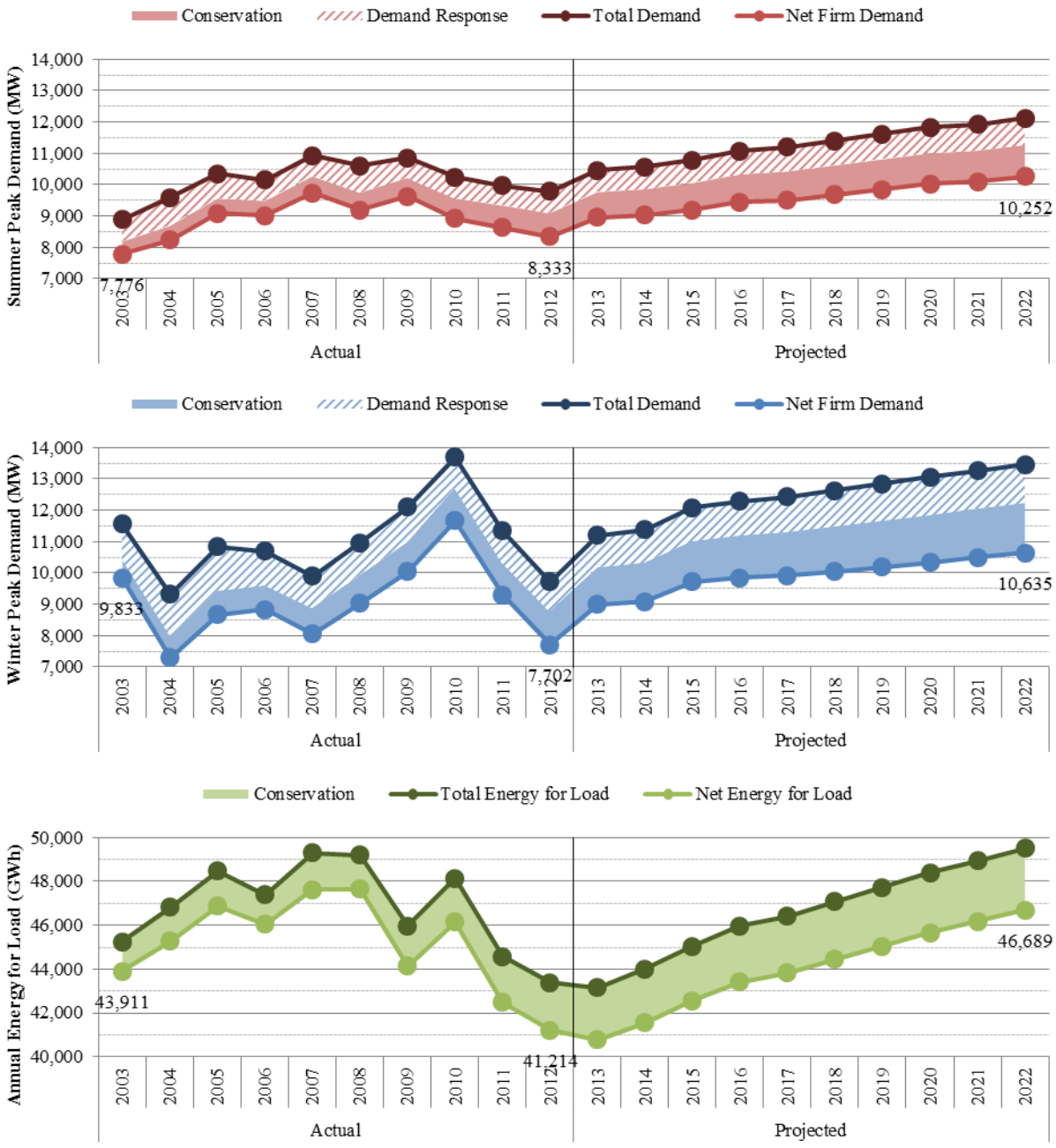
Source: 2013 TYSP Schedule 2

Duke Energy Florida (DEF)

Seasonal Peak Demand & Annual Energy for Load

The following three graphs in Figure 23 show DEF's historic peak demand for both the summer and winter seasons, and net energy for load for the years 2003 through 2012. The forecasted values are also shown through the current planning horizon, including the effect of the utility's DSM programs. Available demand response values are shown below for the previous ten years, but generally these programs have not been activated during summer peak periods. Demand response was utilized during seasonal peak demand periods in the summer of 2005 and winters of 2003, 2006 through 2008, and 2010.

Figure 23: DEF - Seasonal Peak Demand and Annual Energy Consumption (Historic & Forecast)



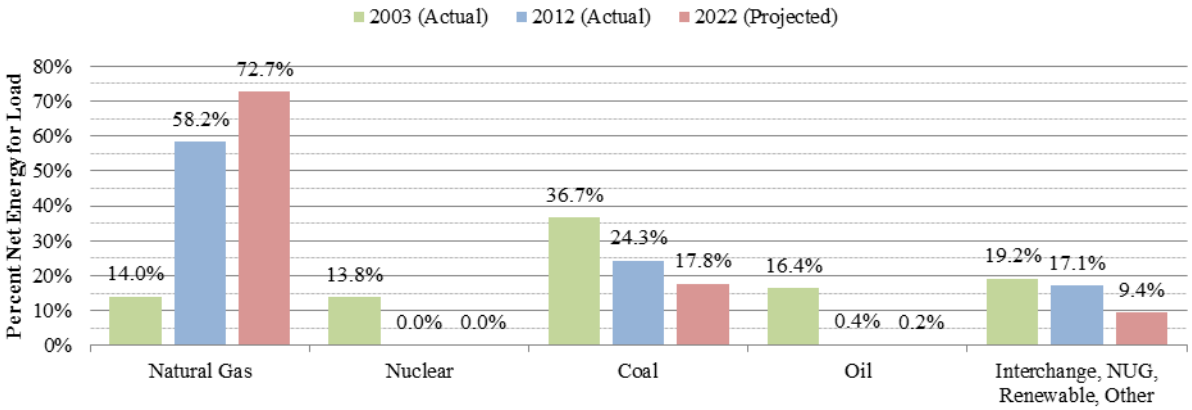
Source: 2013 TYSP Schedule 3

Generation Resources

Fuel Diversity

Figure 24 shows DEF's historic fuel mix for 2003 and 2012, and the projected fuel mix for 2022. DEF's primary generation fuel is natural gas, which has increased from 14 percent of system energy in 2003, to 58.2 percent in 2012. A portion of this increase is due to the retirement of the Crystal River 3 nuclear unit, which previously provided over ten percent of system energy. Coal has the second highest fuel usage, but is anticipated to decline and be replaced by natural gas over the planning period. Purchased power makes up a sizeable portion of DEF's system energy, at 17.1 percent in 2012, with a peak projected in 2017 at 24 percent of system energy. Purchased power is anticipated to decline while natural gas increases with the addition of new natural gas-fired generation discussed below.

Figure 24: DEF - Fuel Diversity (History & Forecast)



Source: 2013 TYSP Schedule 6

Planned Generation

DEF's 2013 TYSP includes three planned generation additions, two combined cycle units and a combustion turbine. All units are unsited at this time. The planned units are detailed below in Table 19. This represents an increase from the company's 2012 TYSP in both number of generating units and total capacity. The previous TYSP had projected a return to service of an uprated Crystal River 3 by the end of 2014 and a single combined cycle unit in 2019.

Table 19: DEF - Planned Generation Additions

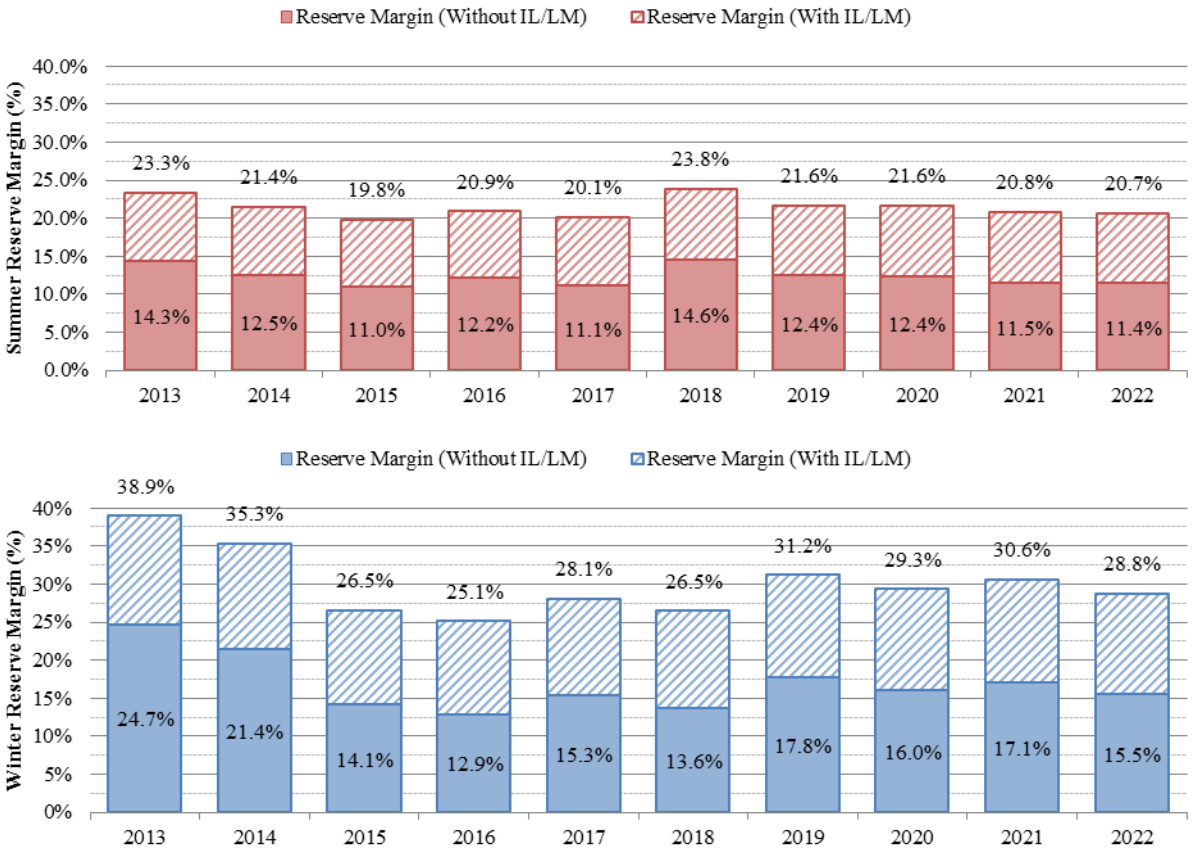
Generating Unit Name	Generator Type	Summer Capacity (MW)	In-Service Date	PPSA
Natural Gas Units				
Unnamed CC 1	Combined Cycle	1,189	06/2018	Required
Unnamed CC 2	Combined Cycle	1,189	06/2020	Required
Unnamed CT 1	Combustion Turbine	187	06/2022	N/A

Source: 2013 TYSP Schedule 8

Reserve Margin

DEF maintains a minimum 20 percent reserve margin for planning purposes based on a stipulation approved by the Commission. Figure 25 displays the forecast planning reserve margin for DEF through the planning period for both seasons including the effects of projected conservation activities. The impact of demand response programs on reserve margin is also included. As shown in the figure, DEF is a summer peaking utility.

Figure 25: DEF - Seasonal Reserve Margin (Summer & Winter)



Source: 2013 TYSP Schedule 7

Due to the retirement of CR3, combined with the potential retirement of oil and coal-fired units totaling over 1,000 MWs due to potential EPA emissions rules, DEF will require a large amount of firm capacity to meet customer demand on a fairly short basis. While DEF projects construction of several generating units within the planning period, the earliest is anticipated to enter service in 2018, after any potential EPA related retirements. Therefore, DEF will require firm purchased power in the interim, especially for summer peaks. The company has issued two requests for proposals, seeking power both from within and outside Florida, and is in the process of negotiating with suppliers. It appears at this time that there is sufficient capacity available from other parties to provide for the required firm capacity purchases. The Commission will continue to monitor DEF's efforts to secure firm capacity for its customers.

Tampa Electric Company (TECO)

TECO is an investor-owned electric utility, and Florida's third largest TYSP utility. The utility's service territory is within the FRCC region, and consists primarily of the Tampa metropolitan area. As TECO is an IOU, the Commission has regulatory authority over all aspects of operations, including rates, reliability, and safety.

Load and Energy Forecast

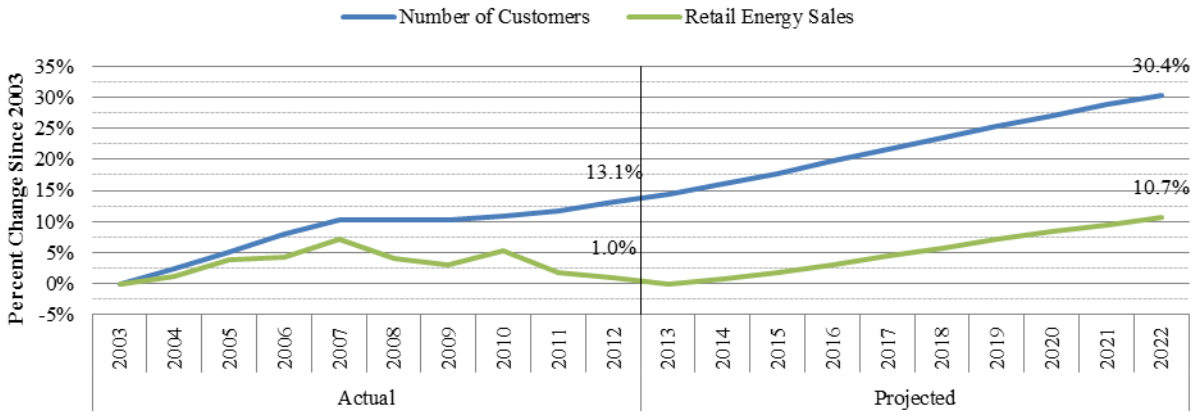
In 2012, TECO had approximately 676,300 customers, with annual retail energy sales of 16,582 GWh, or approximately 8.2 percent of the state of Florida's NEL. Total number of customers and annual energy consumption by customer class are below in Figure 26.

Figure 26: TECO - Number of Customers and Energy Usage by Class

Source: 2013 TYSP Schedule 2

Figure 27 illustrates the company's historic and projected growth as a percentage of its total number of customers and retail energy sales in 2003. Over the last ten years, TECO has increased its total number of customers by 13.1 percent, while increasing retail energy sales by 1.0 percent. The company forecasts continued positive growth most years of the planning period, with retail energy sales exceeding the historic 2007 peak by 2020.

Figure 27: TECO - Customer and Retail Energy Sale Growth Since 2003



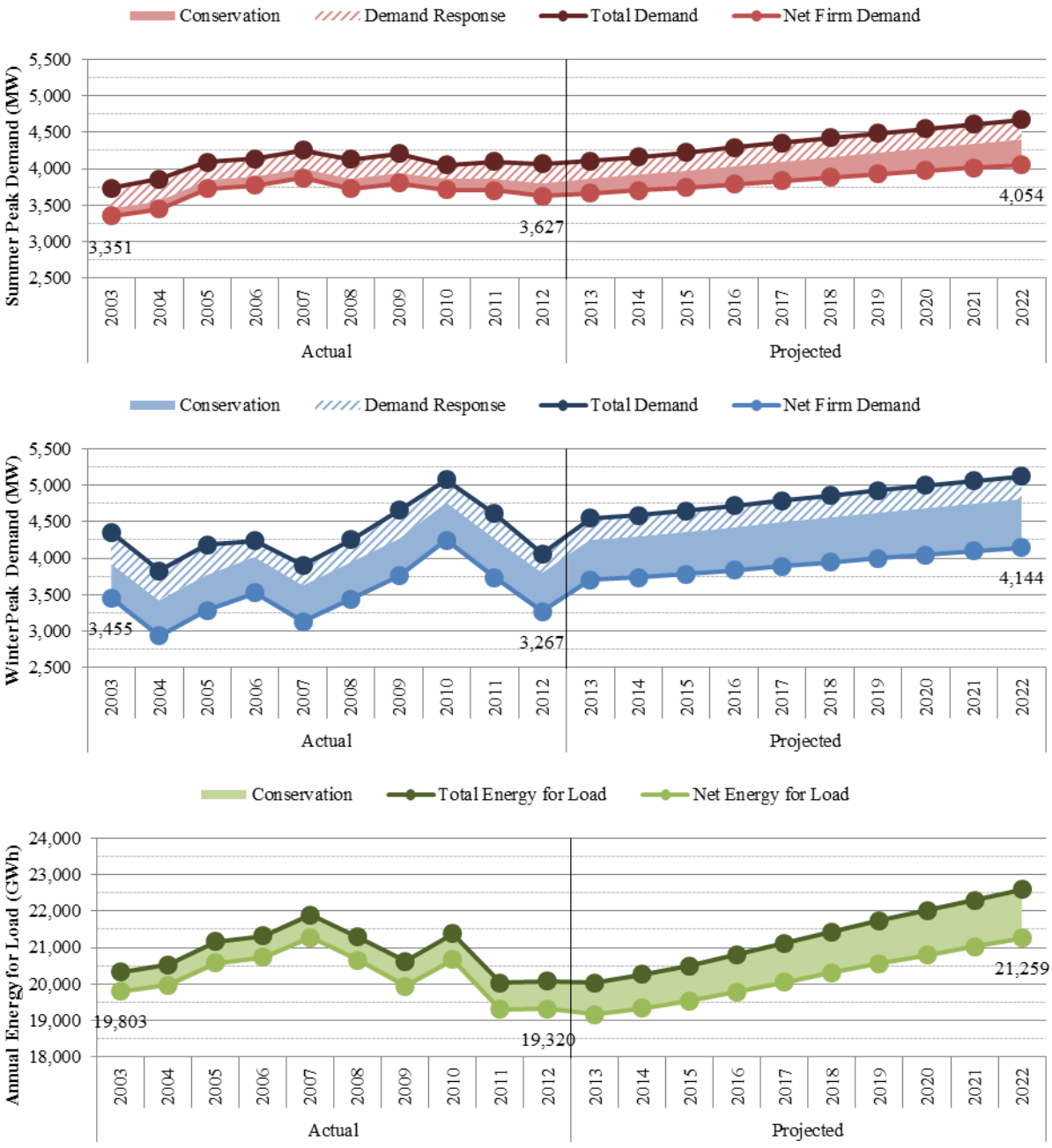
Source: 2013 TYSP Schedule 2

Tampa Electric Company (TECO)

Seasonal Peak Demand & Annual Energy for Load

The following three graphs in Figure 28 show TECO's historic peak demand for both the summer and winter seasons, and net energy for load for the years 2003 through 2012. The forecasted values are also shown through the current planning horizon, including the effect of the utility's DSM programs. Available demand response values are shown below for the previous ten years, but generally these programs have not been activated, excluding three summer peaks, in 2005, 2007, and 2009.

Figure 28: TECO - Seasonal Peak Demand and Annual Energy Consumption (Historic & Forecast)



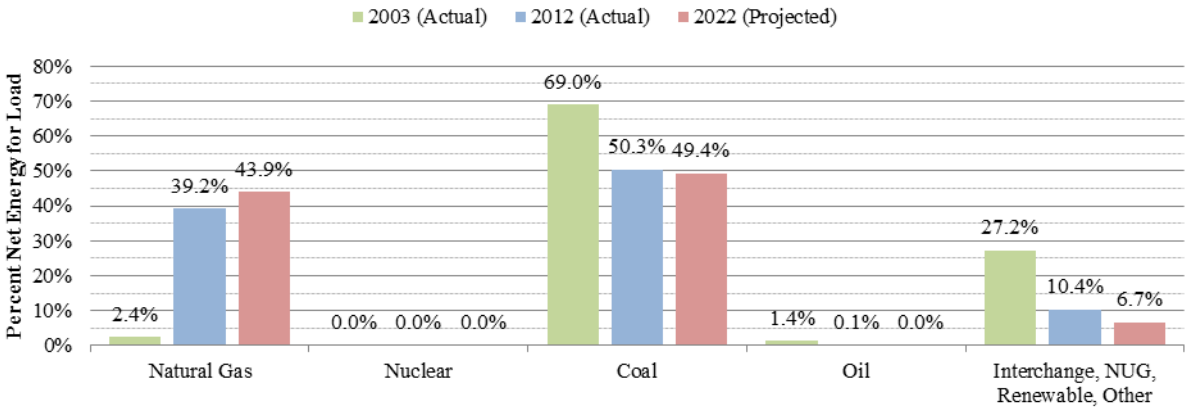
Source: 2013 TYSP Schedule 3

Generation Resources

Fuel Diversity

Figure 29 shows TECO's historic fuel mix for 2003 and 2012, and the projected fuel mix for 2022. TECO's primary generation fuel is coal, one of only two utilities in the state that relied upon the solid fuel over natural gas in 2012, with 50.3 percent of system energy generated by coal. Coal usage has declined however, primarily with the increase of natural gas, which is the next highest fuel for TECO's system energy. Natural gas has risen to 39.2 percent of system energy in 2012, up from only 2.4 percent in 2003. Coal is anticipated to remain the main system fuel throughout the planning period, making up 49.4 percent in 2022, although natural gas is projected to replace purchased power and increase its share of system energy to 43.9 percent in 2022.

Figure 29: TECO - Fuel Diversity (History & Forecast)



Source: 2013 TYSP Schedule 6

Planned Generation

TECO's 2013 TYSP includes two planned generation additions. The first is a modernization of their existing Polk plant site by converting the existing combustion turbines into a combined cycle unit. The second is a combustion turbine to be sited somewhere in Hillsborough County. These units are described below in Table 20. This is consistent with the company's 2012 TYSP, which included similar generating units. The primary change is the increase in capacity and one year delay in the in-service date of the planned combustion turbine.

Table 20: TECO - Planned Generation Additions

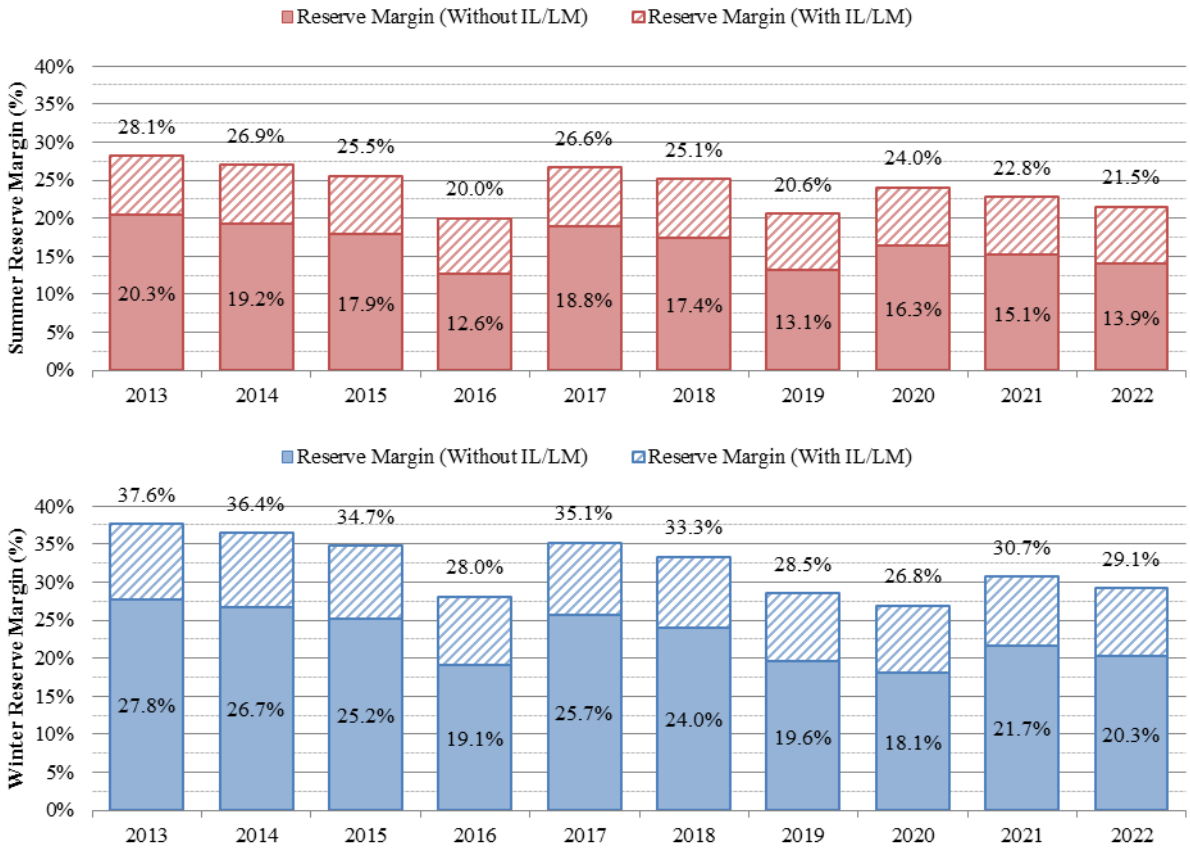
Generating Unit Name	Generator Type	Summer Capacity (MW)	In-Service Date	PPSA
Natural Gas Units				
Polk 2-5 Conversion	Combined Cycle	459	01/2017	Pending
Future CT 1	Combustion Turbine	190	05/2020	N/A

*Represents additional steam capacity from conversion, not including the original CT units.
Source: 2013 TYSP Schedule 8

Reserve Margin

TECO maintains a minimum 20 percent reserve margin for planning purposes based on a stipulation approved by the Commission. Figure 30 displays the forecast planning reserve margin for TECO through the planning period for both seasons including the effects of projected conservation activities. The impact of demand response programs on reserve margin is also included. As shown in the figure, TECO is generally a winter-peaking utility, during certain periods summer peak demand can be of greater concern. TECO also maintains a minimum supply-side contribution to its reserve margin, set at 7 percent, which it exceeds by more than 100 percent in all years of the planning period.

Figure 30: TECO - Seasonal Reserve Margin (Summer & Winter)



Source: 2013 TYSP Schedule 7

GPC is the smallest investor-owned generating utility, and the sixth largest TYSP utility. The utility's service territory includes western Florida. GPC is a member of the Southern Company electric system and has the SERC as its regional reliability entity. Because GPC plans and operates its system in conjunction with the other Southern Company utilities, not all of the energy generated by the GPC units is consumed in Florida. As GPC is an IOU, the Commission has regulatory authority over all aspects of operations, including rates, reliability, and safety.

Load and Energy Forecast

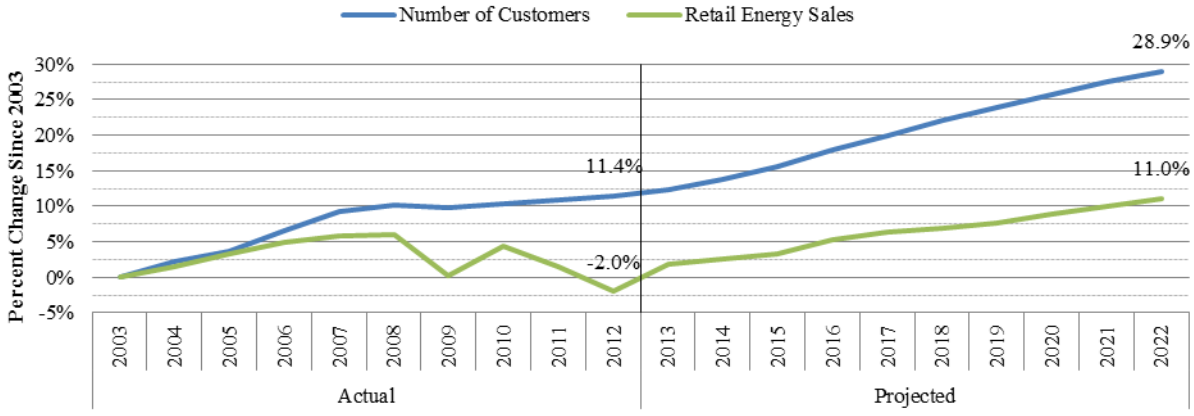
In 2012, GPC had approximately 433,900 customers, with annual retail energy sales of 10,637 GWh, or approximately 4.9 percent of the state of Florida's NEL. Total number of customers and annual energy consumption by customer class are below in Figure 31.

Figure 31: GPC - Number of Customers and Energy Usage by Class

Source: 2013 TYSP Schedule 2

Figure 32 illustrates the company's historic and projected growth as a percentage of its total number of customers and retail energy sales in 2003. Over the last ten years, GPC has increased its number of customers by 11.4 percent, though retail energy sales have declined 2.0 percent. The company forecasts continued positive growth for all of the planning period, with retail energy sales exceeding the historic 2008 peak by 2017.

Figure 32: GPC - Customer and Retail Energy Sale Growth Since 2003



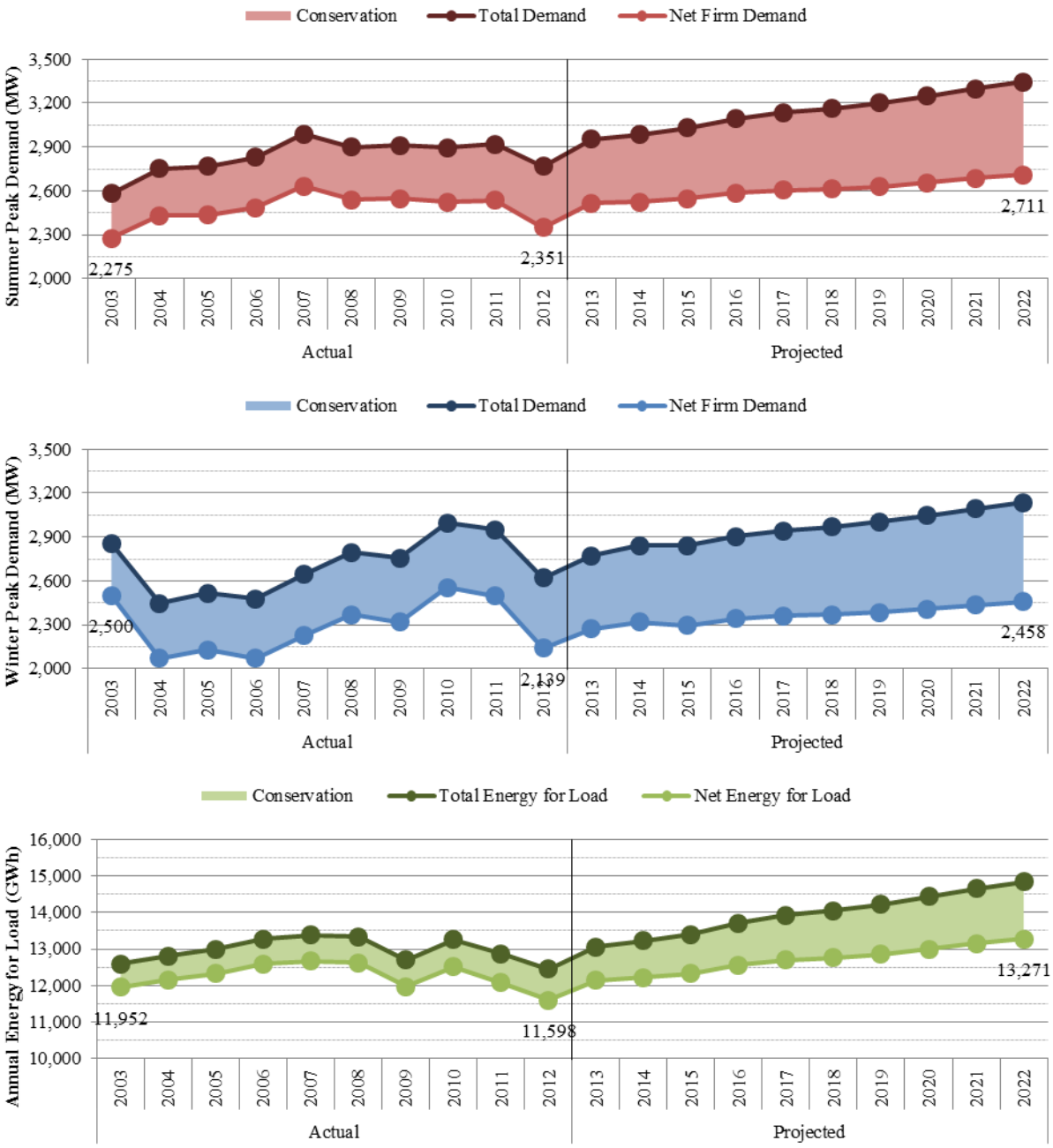
Source: 2013 TYSP Schedule 2

Gulf Power Company (GPC)

Seasonal Peak Demand & Annual Energy for Load

The following three graphs in Figure 33 show GPC's historic peak demand for both the summer and winter seasons, and net energy for load for the years 2003 through 2012. The forecasted values are also shown through the current planning horizon, including the effect of the utility's DSM programs. GPC does not currently include any demand response in its forecasts.

Figure 33: GPC - Seasonal Peak Demand and Annual Energy Consumption (Historic & Forecast)



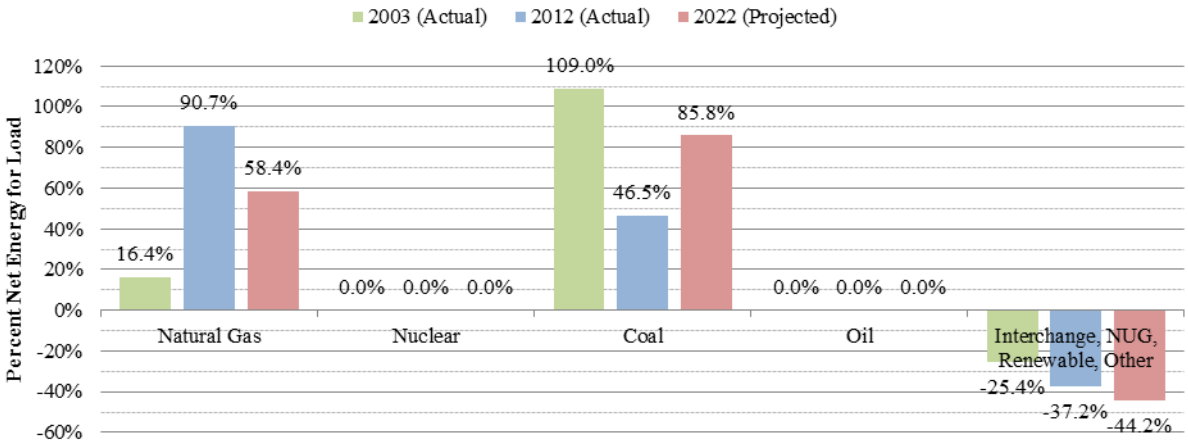
Source: 2013 TYSP Schedule 3

Generation Resources

Fuel Diversity

Figure 34 shows GPC's historic fuel mix for 2003 and 2012, and the projected fuel mix for 2022. GPC is a net energy exporter, and as a result produces more energy than its system consumes each year, with exports planned to increase over the planning period. GPC's primary fuel in 2012 was natural gas, at 90.7 percent of system energy, which displaced coal for the first time in the past ten years. Coal has declined from producing 109 percent of system energy in 2003, to only 46.5 percent in 2012. By the end of the planning period, GPC forecasts that coal will once again become the dominant system fuel, at 85.8 percent, with natural gas still contributing over half of system energy, at 58.4 percent.

Figure 34: GPC - Fuel Diversity (History & Forecast)



Source: 2013 TYSP Schedule 6

Planned Generation

GPC's 2013 TYSP included a single generation addition at their existing Perdido landfill gas site in Escambia County. This is an increase from the company's 2012 TYSP, which included no new generating units.

Table 21

Table 21: GPC - Planned Generation Additions

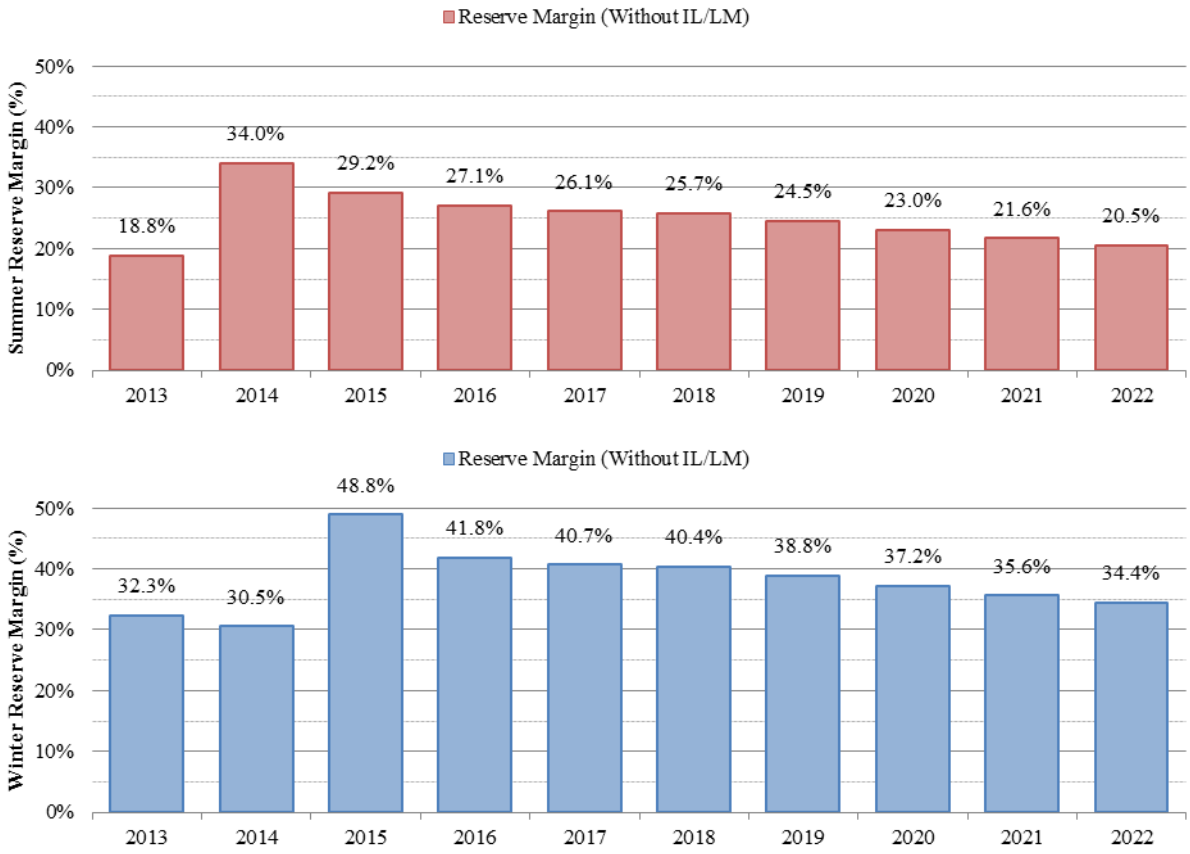
Generating Unit Name	Generator Type	Summer Capacity (MW)	In-Service Date	PPSA
Renewable Units				
Perdido 3	Landfill Gas-fired IC	1.8	8/2014	N/A

Source: 2013 TYSP Schedule 8

Reserve Margin

GPC is not within the FRCC region, and therefore not subject to its minimum reserve margin requirements. GPC operates within SERC, and as part of the Southern Power Pool has a planning reserve margin of 15 percent after 2015. Figure 35 displays the forecasted planning reserve margin for GPC through the planning period for both seasons, including the effects of projected conservation activities. As shown in the figure, GPC is a winter-peaking utility for most years and has sufficient reserve margin to meet projected customer demands for both seasons throughout the planning period.

Figure 35: GPC - Seasonal Reserve Margin (Summer & Winter)



Source: 2013 TYSP Schedule 7

Florida Municipal Power Agency (FMPA)

FMPA is a governmental wholesale power company owned by multiple municipal electric utilities located throughout Florida. It is collectively the state's eighth largest TYSP utility. As FMPA is a municipal utility, the Commission's regulatory authority is limited to safety, rate structure, territorial boundaries, bulk power supply, operations, and planning. FMPA's direct responsibility for power supply is with the All-Requirements Power Supply Project (ARP). FMPA plans and supplies all of the power requirements for the ARP utilities

Load and Energy Forecast

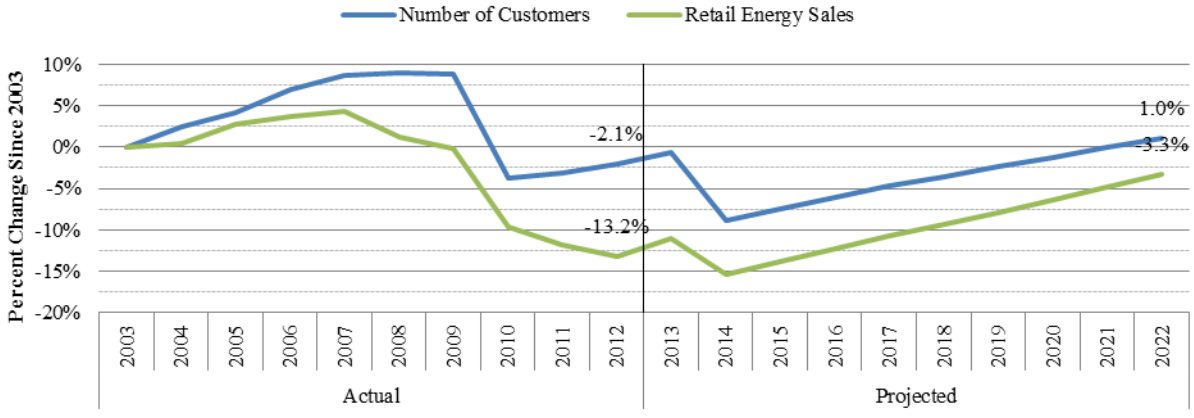
In 2012, FMPA's members had approximately 265,300 customers, with total retail energy sales of 5,549 GWh, or approximately 2.6 percent of the state of Florida's NEL. Total number of customers and annual energy consumption by customer class are below in Figure 36.

Figure 36: FMPA - Number of Customers and Energy Usage by Class

Source: 2013 TYSP Schedule 2

Figure 37 illustrates the company's historic and projected growth as a percentage of its total number of customers and retail energy sales in 2003. Over the last ten years, FMPA has seen a decrease in customers by 2.1 percent, and a decrease in retail energy sales by 13.2 percent. The company does not project to exceed its 2003 retail energy sales within the next ten years.

Figure 37: FMPA - Customer and Retail Energy Sale Growth Since 2003



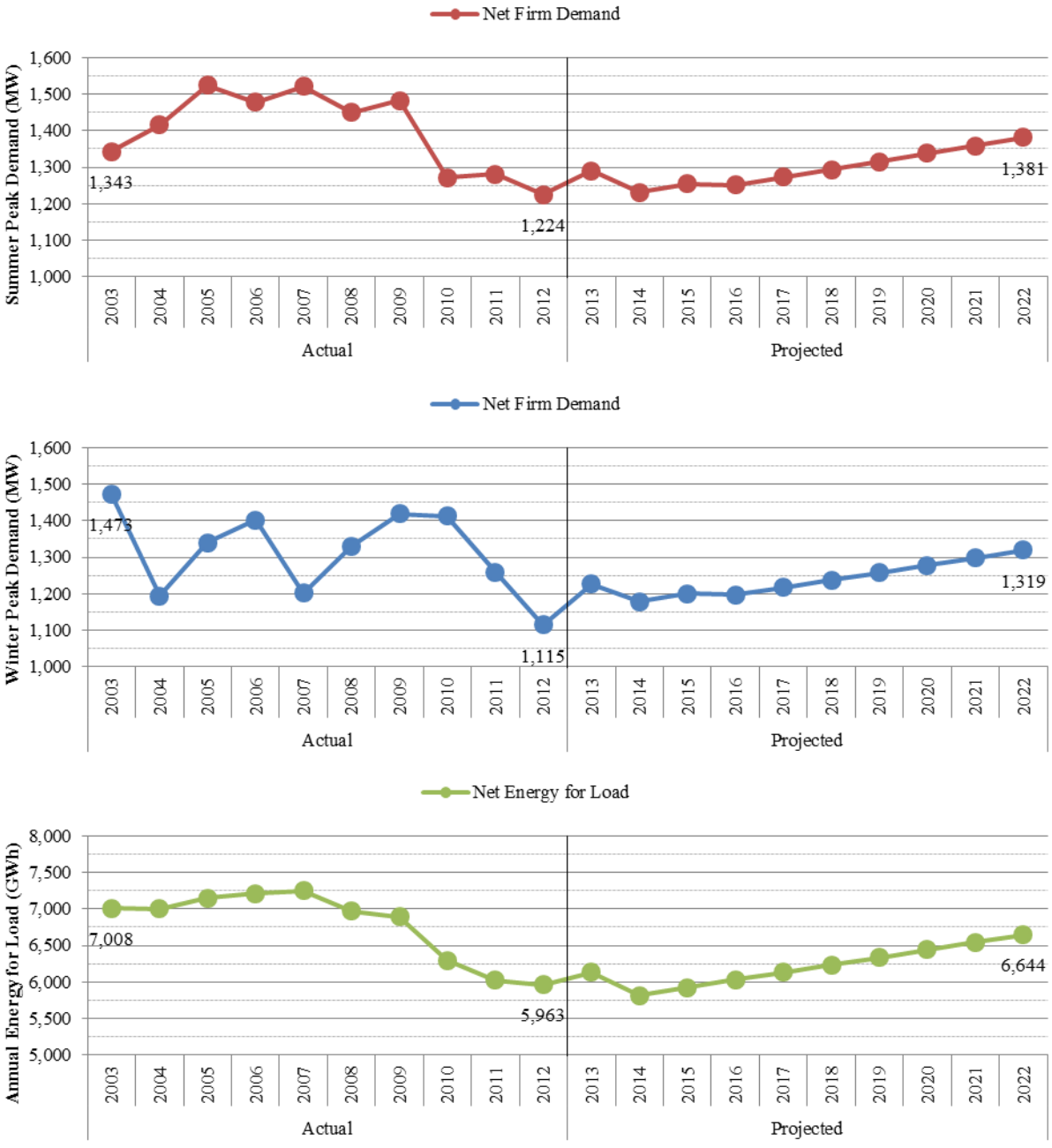
Source: 2013 TYSP Schedule 2

Florida Municipal Power Agency (FMPA)

Seasonal Peak Demand & Annual Energy for Load

The following three graphs in Figure 38 show FMPA's historic peak demand for both the summer and winter seasons, and net energy for load for the years 2003 through 2012. The forecasted values are also shown through the current planning horizon, including the effect of member utility's DSM programs. As FMPA did not provide separate annual conservation data, only the utility's net firm demand and net energy for load are shown below.

Figure 38: FMPA - Seasonal Peak Demand and Annual Energy Consumption (Historic & Forecast)



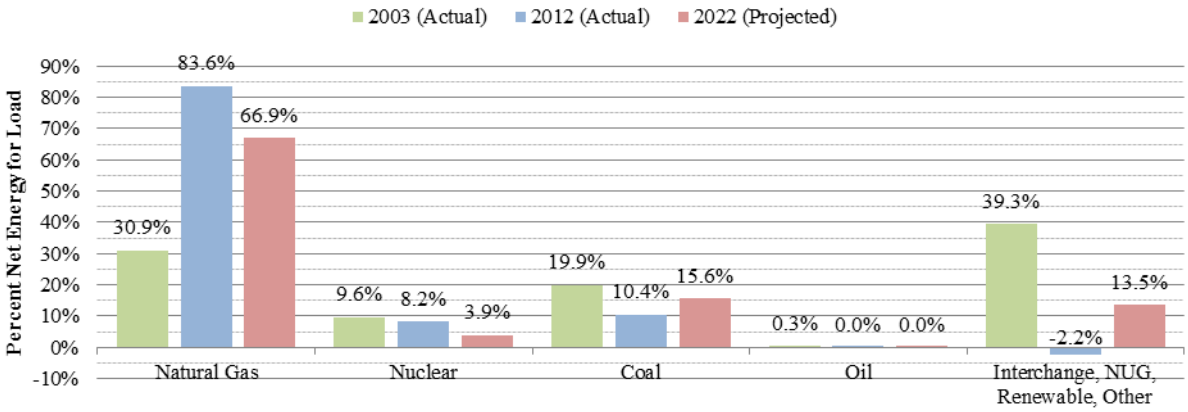
Source: 2013 TYSP Schedule 3

Generation Resources

Fuel Diversity

Figure 39 shows FMPA's historic fuel mix for 2003 and 2012, and the projected fuel mix for 2022. Natural gas is the primary generation fuel on FMPA's system, contributing 81.9 percent of system energy in 2012. A slight reduction in usage is forecast by 2022, with an increase in purchased power and coal usage reducing natural gas to approximately two-thirds of energy generation.

Figure 39: FMPA - Fuel Diversity (History & Forecast)



Source: 2013 TYSP Schedule 6

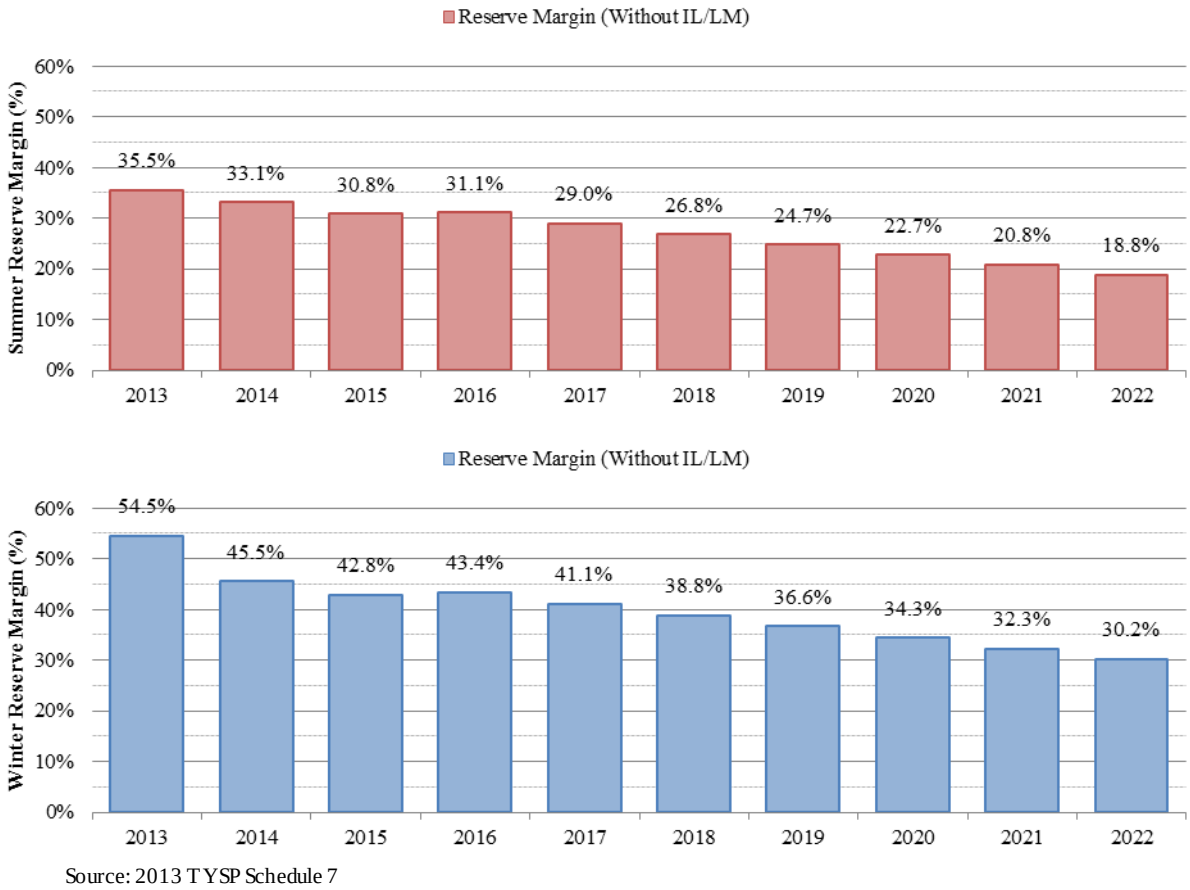
Planned Generation

FMPA's 2013 TYSP did not contain any planned generation additions. This is consistent with the company's 2012 TYSP, which also included no new generation through 2021.

Reserve Margin

FMPA maintains a 15 percent reserve margin based on FRCC planning requirements. In addition, the utility uses a planning reserve margin of 18 percent for summer peak reserve margin planning. Figure 40 displays the forecasted planning reserve margin for FMPA through the planning period for both seasons, including the effects of projected conservation activities. As shown in the figure, FMPA is a summer-peaking utility and has sufficient reserve margin to meet projected customer demands for both seasons throughout the planning period.

Figure 40: FMPA - Seasonal Reserve Margin (Summer & Winter)



Source: 2013 TYSP Schedule 7

Gainesville Regional Utilities (GRU)

GRU is a municipal utility and the state's smallest TYSP utility. The company's service area is within the FRCC region, and includes the City of Gainesville and its surrounding urban area. GRU also provides wholesale power to the City of Alachua and Clay Electric Cooperative. As GRU is a municipal utility, the Commission's regulatory authority is limited to safety, rate structure, territorial boundaries, bulk power supply, operations, and planning

Load and Energy Forecast

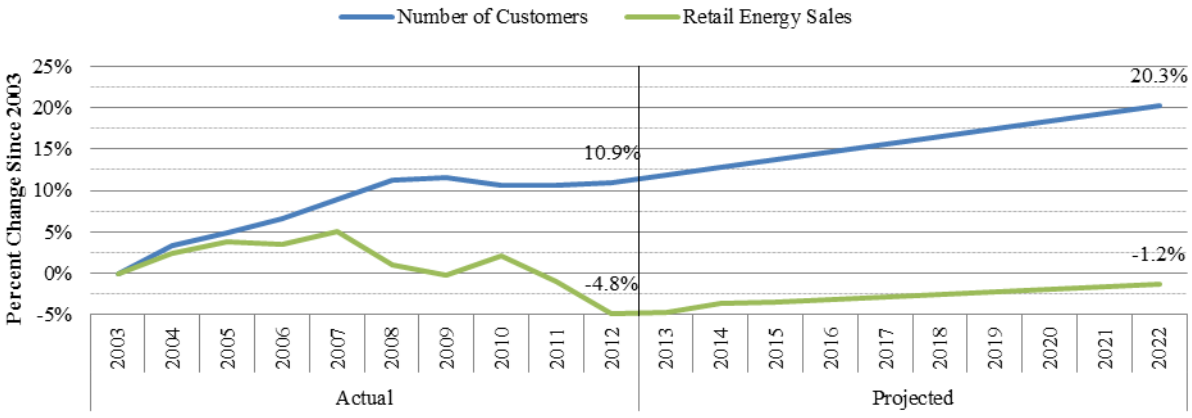
In 2012, GRU had approximately 95,600 customers, with annual retail energy sales of 1,675 GWh, or approximately 0.8 percent of the state of Florida's NEL. Total number of customers and annual energy consumption by customer class are below in Figure 41.

Figure 41: GRU - Number of Customers and Energy Usage by Class

Source: 2013 TYSP Schedule 2

Figure 42 illustrates the company's historic and projected growth as a percentage of its total number of customers and retail energy sales in 2003. Over the last ten years, GRU has increased its number of customers by 10.9 percent, but retail energy sales have declined 4.8 percent. The company forecasts positive growth for the entire planning period, but does not project retail energy sales to exceed its 2003 level within the next ten years.

Figure 42: GRU - Customer and Retail Energy Sale Growth Since 2003

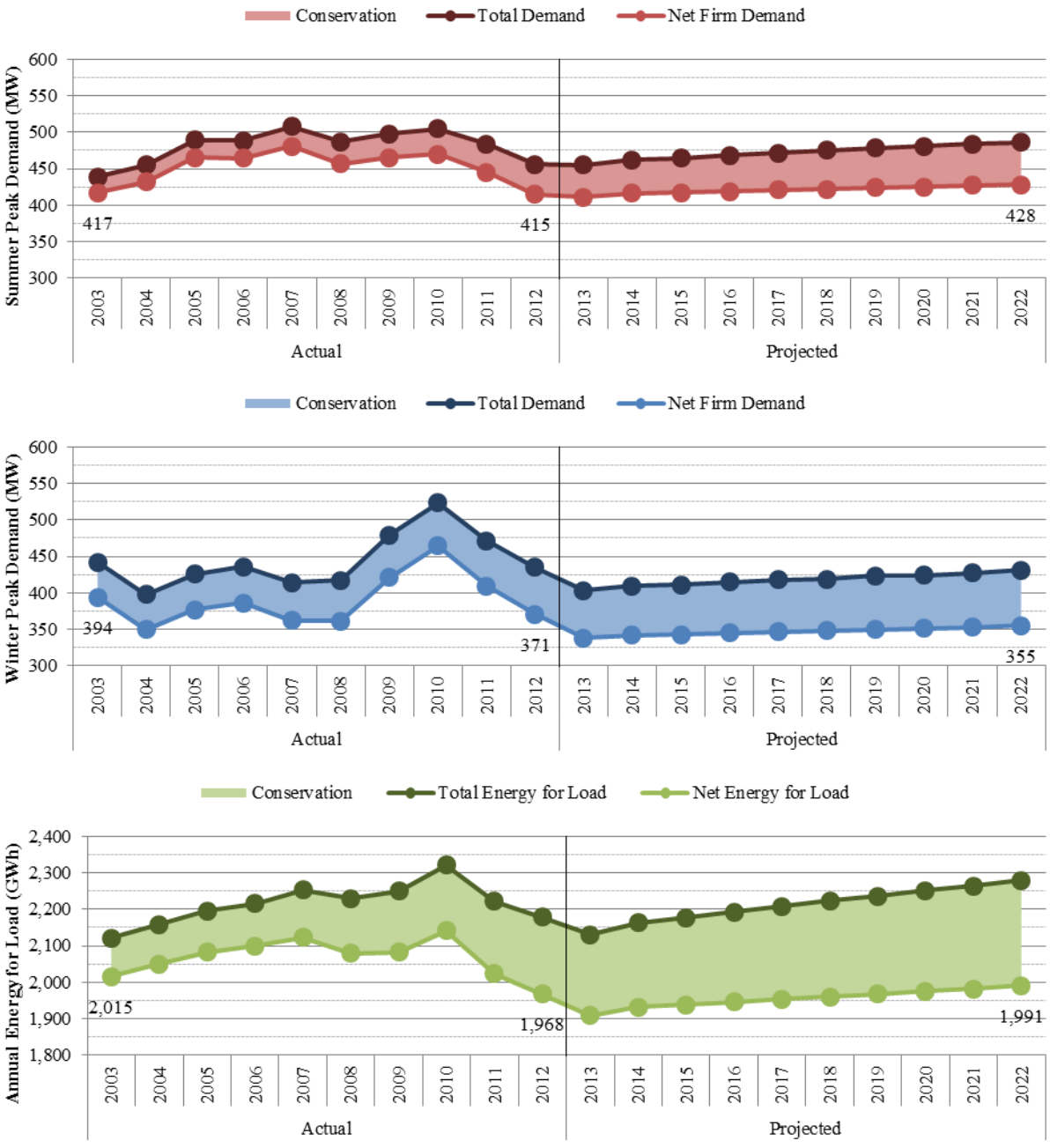


Source: 2013 TYSP Schedule 2

Seasonal Peak Demand & Annual Energy for Load

The following three graphs in Figure 43 show GRU's historic peak demand for both the summer and winter seasons, and net energy for load for the years 2003 through 2012. The forecasted values are also shown through the current planning horizon, including the effect of the utility's DSM programs.

Figure 43: GRU - Seasonal Peak Demand and Annual Energy Consumption (Historic & Forecast)



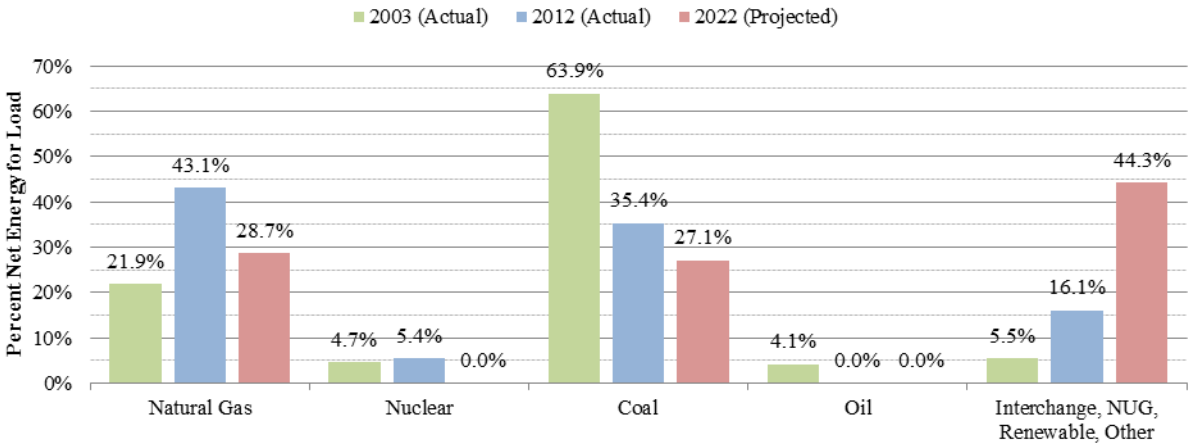
Source: 2013 TYSP Schedule 3

Generation Resources

Fuel Diversity

Figure 44 shows GRU's historic fuel mix for 2003 and 2012, and the projected fuel mix for 2022. While the company has historically relied upon coal, natural gas was the dominant fuel in 2012, producing 43.1 percent of energy, over coal's contribution of 35.4 percent. All forms of native fuel use, including natural gas, nuclear, and coal, are anticipated to decline as purchased power is forecast to become the dominant fuel in 2022. A majority of this purchased power is associated with a single renewable PPA with the Gainesville Renewable Energy Center, a 100 MW biomass plant that utilizes wood and wood wastes for fuel.

Figure 44: GRU - Fuel Diversity (History & Forecast)



Source: 2013 TYSP Schedule 6

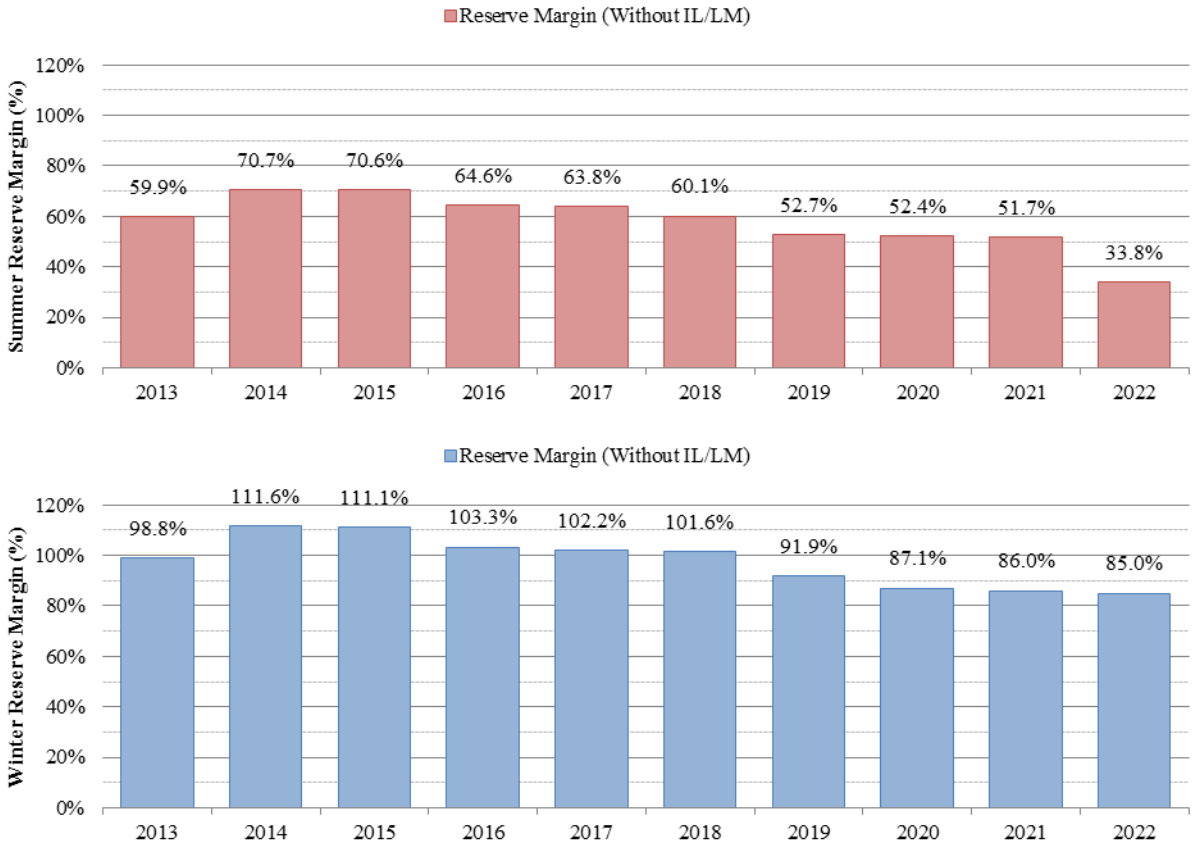
Planned Generation

GRU's 2013 TYSP did not contain any planned generation additions. This is consistent with the company's 2012 TYSP, which also included no new generation through 2021.

Reserve Margin

GRU maintains a 15 percent reserve margin based on FRCC planning requirements. Figure 45 displays the forecasted planning reserve margin for GRU through the planning period for both seasons, including the effects of projected conservation activities. As shown in the figure, GRU is a summer-peaking utility. As the figure below illustrates, GRU's reserve margin is forecasted to remain well above the minimum level throughout the planning period.

Figure 45: GRU - Seasonal Reserve Margin (Summer & Winter)



Source: 2013 TYSP Schedule 7

JEA

JEA, formerly known as Jacksonville Electric Authority, is a municipal electric utility, and the state's fifth largest TYSP utility, and is the largest generating municipal 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 JEA is a municipal utility, the Commission's regulatory authority is limited to safety, rate structure, territorial boundaries, bulk power supply, operations, and planning.

Load and Energy Forecast

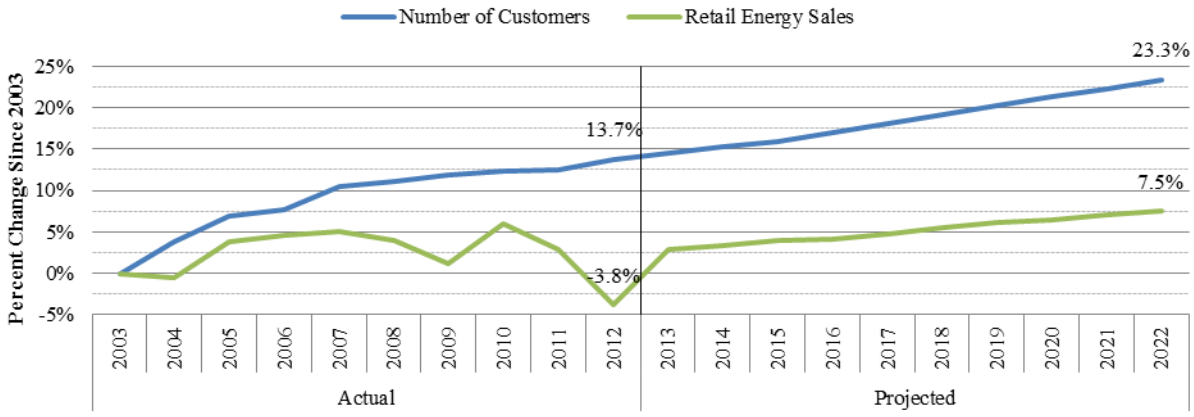
In 2012, JEA had approximately 420,600 customers, with annual retail energy sales of 11,540 GWh, or approximately 5.3 percent of the state of Florida's NEL. Total number of customers and annual energy consumption by customer class are below in Figure 46.

Figure 46: JEA - Number of Customers and Energy Usage by Class

Source: 2013 TYSP Schedule 2

Figure 47 illustrates the company's historic and projected growth as a percentage of its total number of customers and retail energy sales in 2003. Over the last ten years, JEA has increased its number of customers by 13.7 percent, but retail energy sales have declined 3.8 percent. The company forecast growth for the entire planning period, with retail energy sales exceeding the historic 2010 peak by 2019.

Figure 47: JEA - Customer and Retail Energy Sale Growth Since 2003

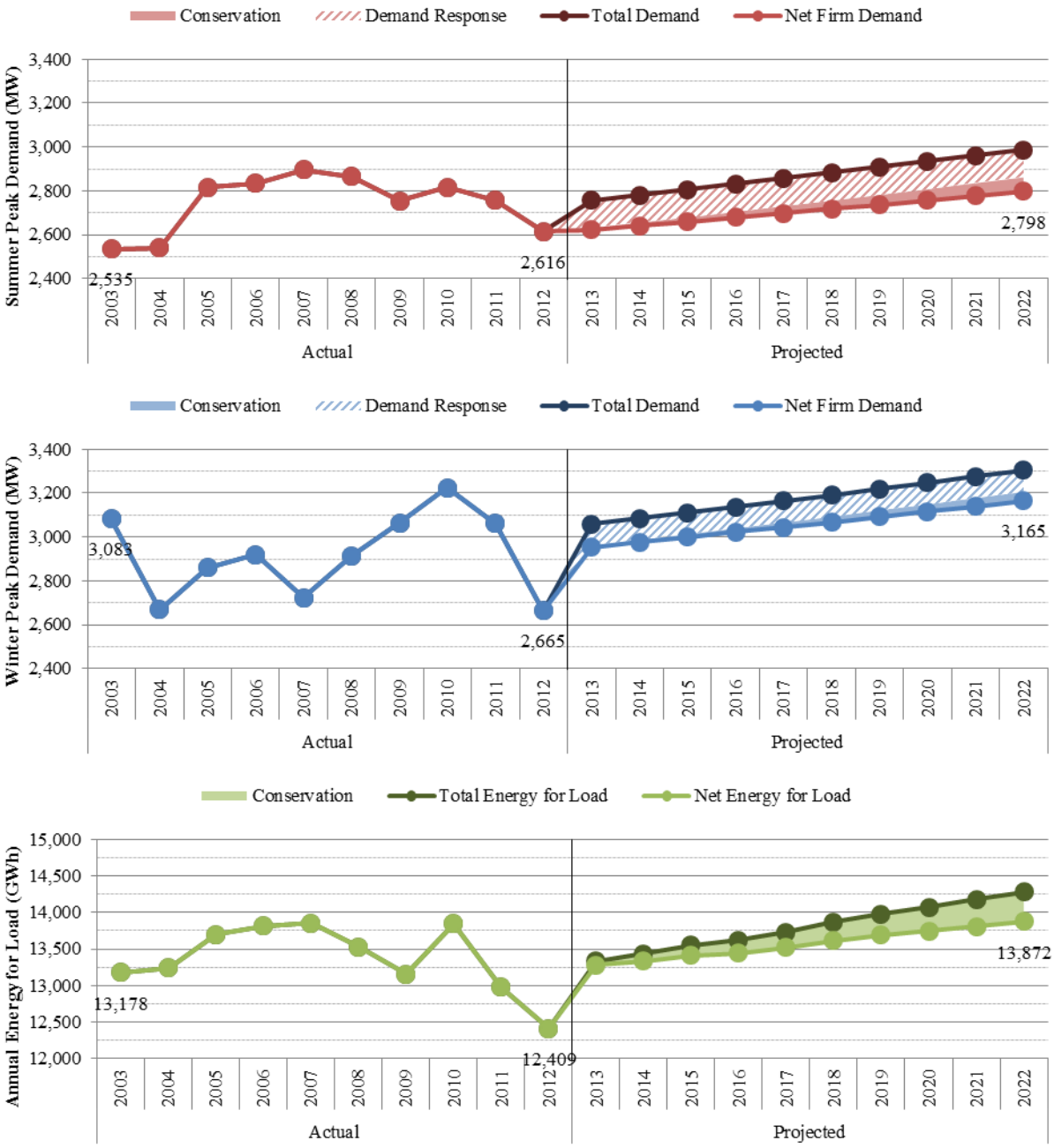


Source: 2013 TYSP Schedule 2

Seasonal Peak Demand & Annual Energy for Load

The following three graphs in Figure 48 show JEA's historic peak demand for both the summer and winter seasons, and net energy for load for the years 2003 through 2012. The forecasted values are also shown through the current planning horizon, including the effect of the utility's DSM programs. Historic conservation data is not available, so only net firm demand and net energy for load is shown for the previous ten years.

Figure 48: JEA - Seasonal Peak Demand and Annual Energy Consumption (Historic & Forecast)



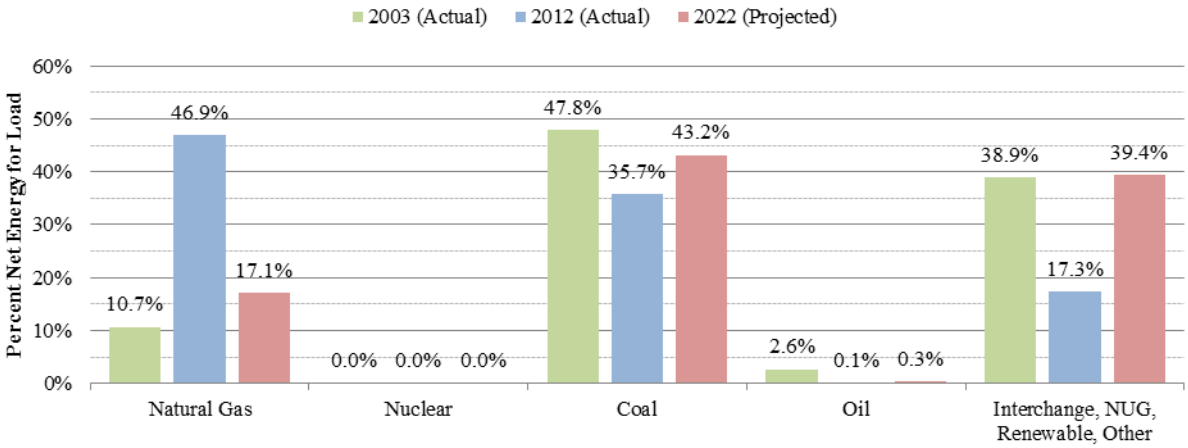
Source: 2013 TYSP Schedule 3

Generation Resources

Fuel Diversity

Figure 49 shows JEA's historic fuel mix for 2003 and 2012, and the projected fuel mix for 2022. Natural gas was the primary fuel on JEA's system in 2012, contributing 46.9 percent of energy. Coal is anticipated to become the dominant fuel by the end of the planning period, with 43.2 percent system energy in 2022, with the next largest fuel source being the combined category of interchange, non-utility generators, renewables, and other fuels. Petroleum coke, classified as 'other' below, makes up a majority of this category for JEA.

Figure 49: JEA - Fuel Diversity (History & Forecast)



Source: 2013 TYSP Schedule 6

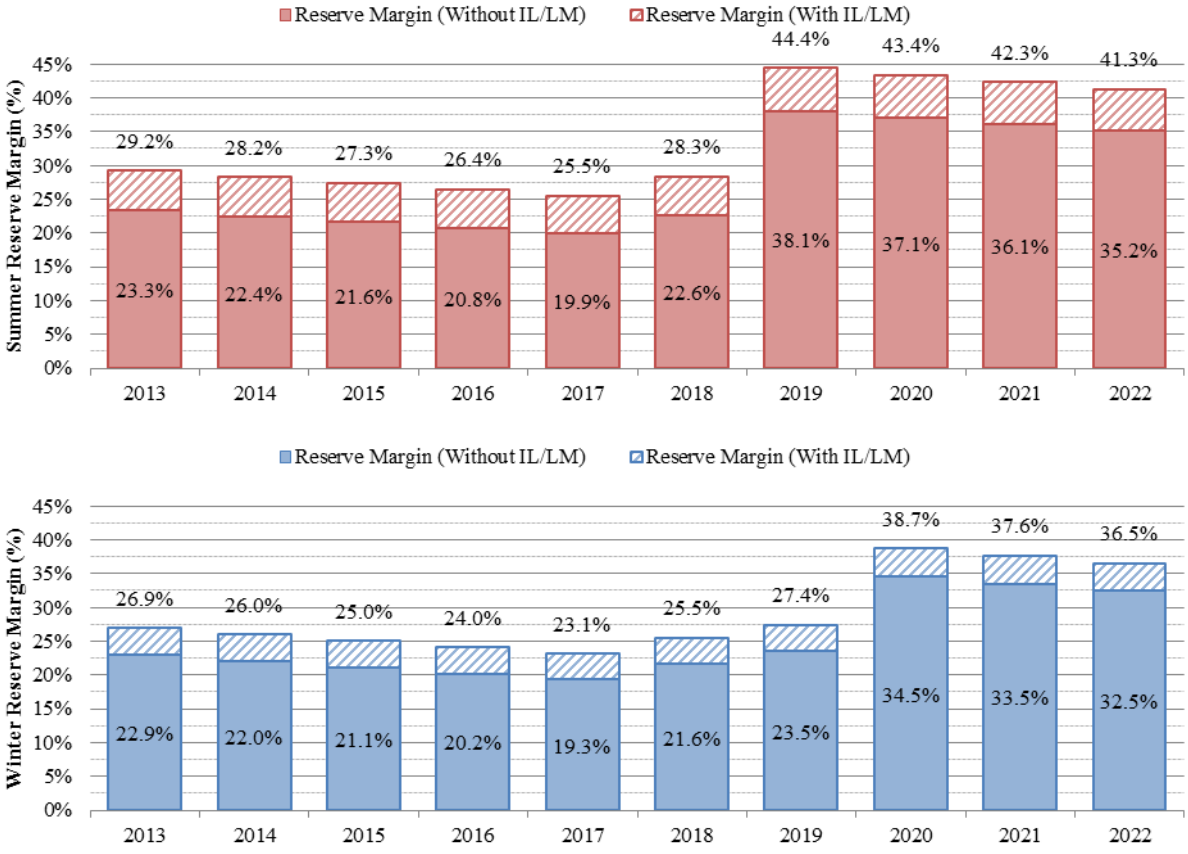
Planned Generation

JEA's 2013 TYSP did not contain any planned generation additions. This is consistent with the company's 2012 TYSP, which also included no new generation through 2021.

Reserve Margin

JEA maintains a 15 percent reserve margin based on FRCC planning requirements. Figure 50 displays the forecasted planning reserve margin for JEA through the planning period for both seasons, including the effects of projected conservation activities. The impact of demand response programs is also included in the figure below. As shown in the figure, JEA is a winter-peaking utility and has sufficient reserve margin to meet projected customer demands for both seasons throughout the planning period. The increase in reserve margin in 2019 is associated with the expiration of a power sale with FPL from a jointly owned unit. FPL anticipates this sale will expire at an earlier period, in 2017.

Figure 50: JEA - Seasonal Reserve Margin (Summer & Winter)



Source: 2013 TYSP Schedule 7

Lakeland Electric (LAK)

LAK is the municipal utility, and is the state's third smallest TYSP utility. LAK is owned and operated by the City of Lakeland. As LAK is a municipal utility, the Commission's regulatory authority is limited to safety, rate structure, territorial boundaries, bulk power supply, operations, and planning.

Load and Energy Forecast

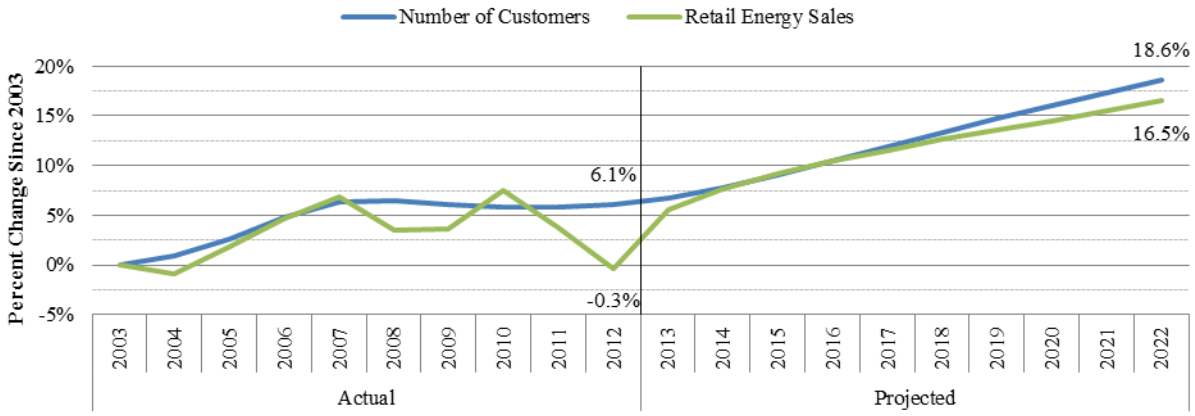
In 2012, LAK had approximately 113,100 customers, with annual retail energy sales of 2,612 GWh, or approximately 1.2 percent of the state of Florida's NEL. Total number of customers and annual energy consumption by customer class are below in Figure 51.

Figure 51: LAK - Number of Customers and Energy Usage by Class

Source: 2013 TYSP Schedule 2

Figure 52 illustrates the company's historic and projected growth as a percentage of its total number of customers and retail energy sales in 2003. Over the last ten years, LAK has increased its number of customers by 6.1 percent, while retail energy sales have declined 0.3 percent. The company forecasts positive growth for all years of the planning period, with retail energy sales exceeding the historic 2010 peak by 2014.

Figure 52: LAK - Customer and Retail Energy Sale Growth Since 2003



Source: 2013 TYSP Schedule 2

Seasonal Peak Demand & Annual Energy for Load

The following three graphs in Figure 53 show LAK's historic peak demand for both the summer and winter seasons, and net energy for load for the years 2003 through 2012. The forecasted values are also shown through the current planning horizon, including the effect of the utility's DSM programs. As LAK did not provide separate annual conservation data, only the utility's net firm demand and net energy for load are shown below.

Figure 53: LAK - Seasonal Peak Demand and Annual Energy Consumption (Historic & Forecast)

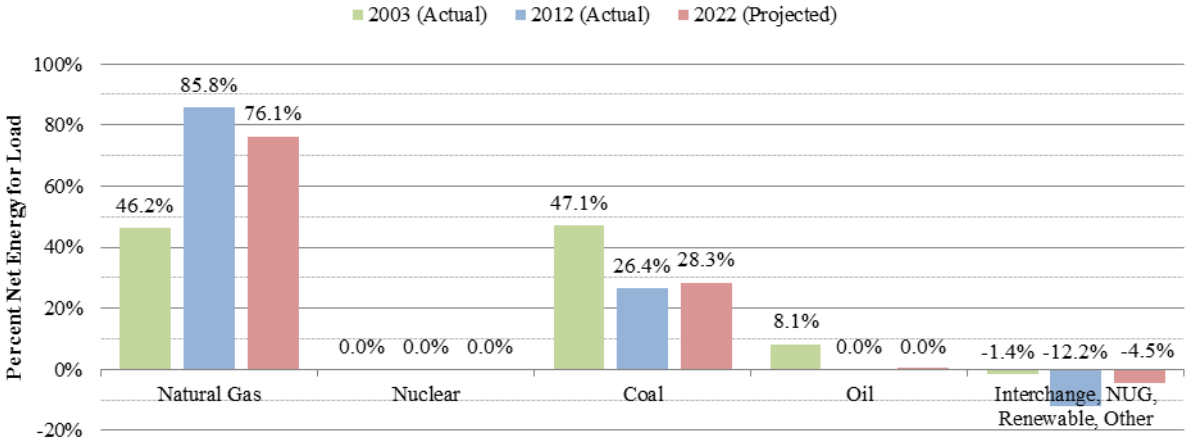
Source: 2013 TYSP Schedule 3

Generation Resources

Fuel Diversity

Figure 54 shows LAK's historic fuel mix for 2003 and 2012, and the projected fuel mix for 2022. Natural gas was the primary fuel on LAK's system, contributing 85.8 percent of system energy. With a total of 12.2 percent of system energy as exports, coal made up the remaining generation. Overall, natural gas is forecast to slightly decline along with exports, while coal remains at a little over a quarter of system energy.

Figure 54: LAK - Fuel Diversity (History & Forecast)



Source: 2013 TYSP Schedule 6

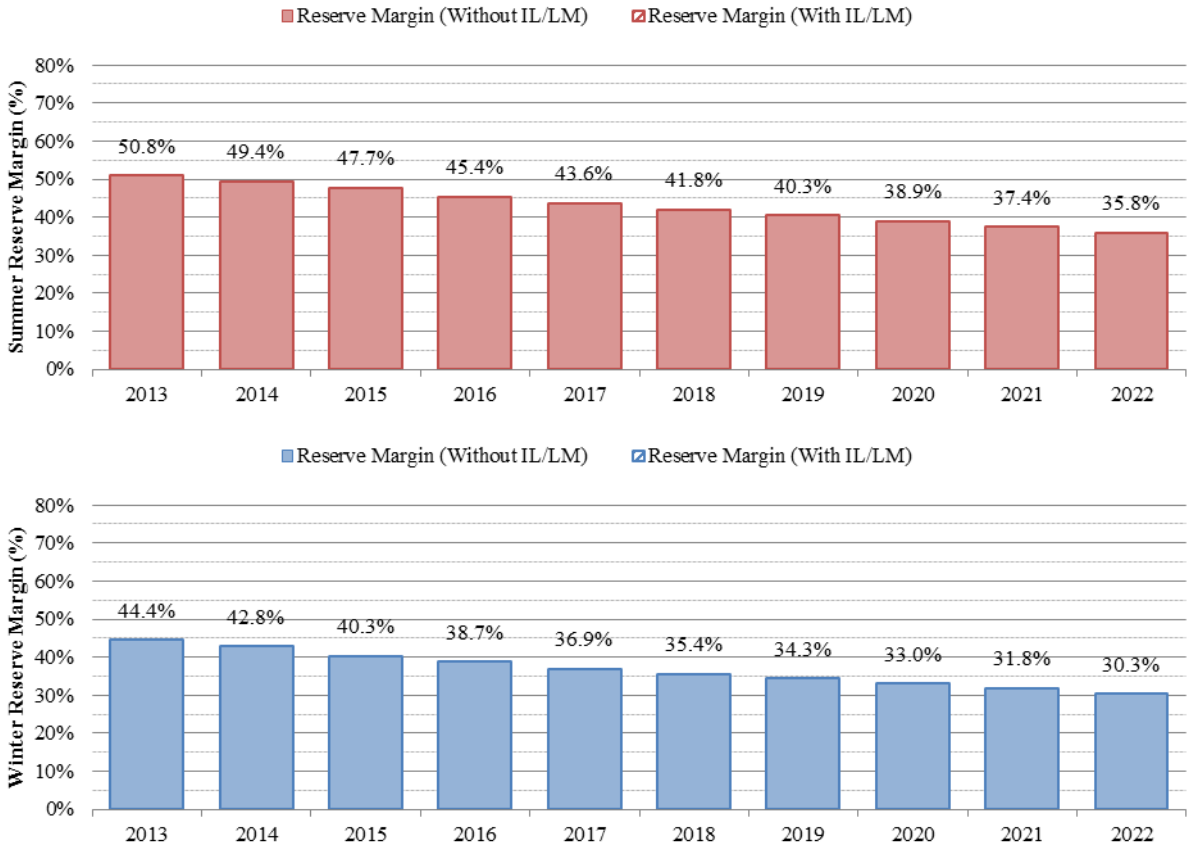
Planned Generation

LAK's 2013 TYSP did not contain any planned generation additions. This is consistent with the company's 2012 TYSP, which also included no new generation additions through 2021.

Reserve Margin

LAK maintains a 15 percent reserve margin based on FRCC planning requirements. Figure 55 displays the forecasted planning reserve margin for LAK through the planning period for both seasons, including the effects of projected conservation activities. As shown in the figure, LAK is a winter-peaking utility for most years and has sufficient reserve margin to meet projected customer demands for both seasons throughout the planning period.

Figure 55: LAK - Seasonal Reserve Margin (Summer & Winter)



Source: 2013 TYSP Schedule 7

Orlando Utilities Commission (OUC)

OUC is a municipal utility, and the state's seventh largest TYSP utility. The utility's service territory is within the FRCC region, and serves the Orlando metropolitan area. As OUC is a municipal utility, the Commission's regulatory authority is limited to safety, rate structure, territorial boundaries, bulk power supply, operations, and planning.

Load and Energy Forecast

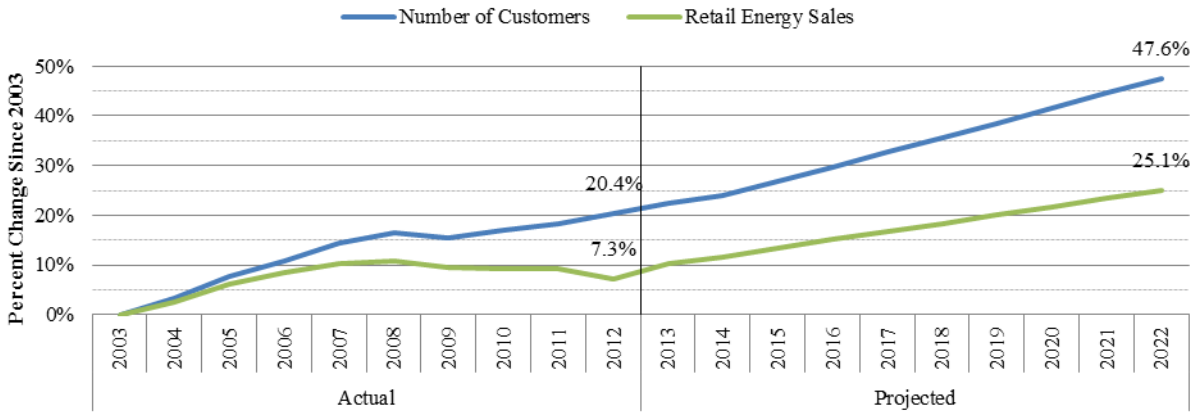
In 2012, OUC had approximately 213,300 customers, with annual retail energy sales of 5,851 GWh, or approximately 3 percent of the state of Florida's NEL. Total number of customers and annual energy consumption by customer class are below in Figure 56.

Figure 56: OUC - Number of Customers and Energy Usage by Class

Source: 2013 TYSP Schedule 2

Figure 57 illustrates the company's historic and projected growth as a percentage of its total number of customers and retail energy sales in 2003. Over the last ten years, OUC has increased its number of customers by 20.4 percent, and retail energy sales have increased by 7.3 percent. The company forecasts continued positive growth throughout the planning period, with retail energy sales exceeding the historic 2008 peak by 2014.

Figure 57: OUC - Customer and Retail Energy Sale Growth Since 2003

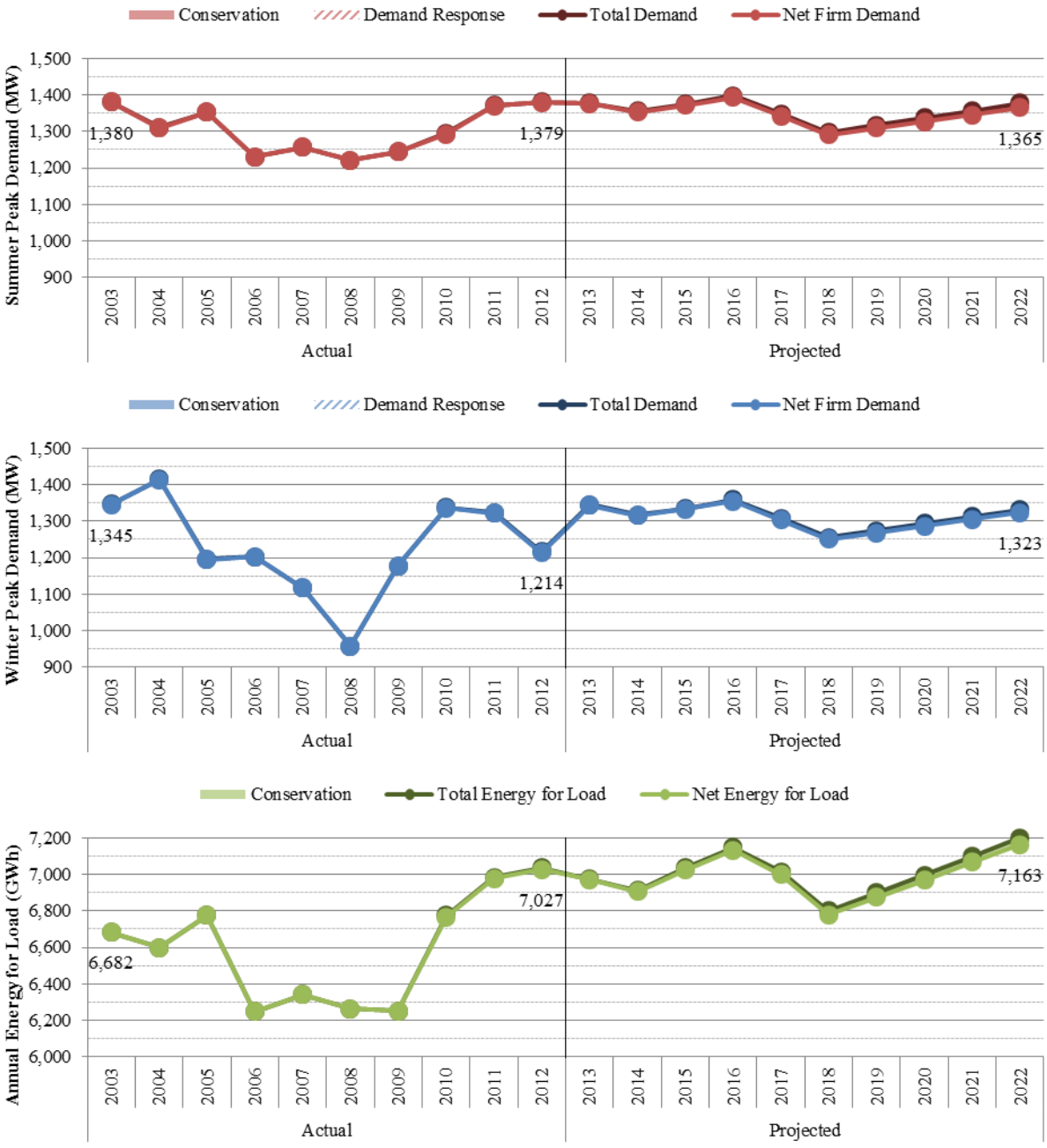


Source: 2013 TYSP Schedule 2

Seasonal Peak Demand & Annual Energy for Load

The following three graphs in Figure 58 show OUC's historic peak demand for both the summer and winter seasons, and net energy for load for the years 2003 through 2012. The forecasted values are also shown through the current planning horizon. Figure 58 below includes the effect of the utility's DSM programs.

Figure 58: OUC - Seasonal Peak Demand and Annual Energy Consumption (Historic & Forecast)



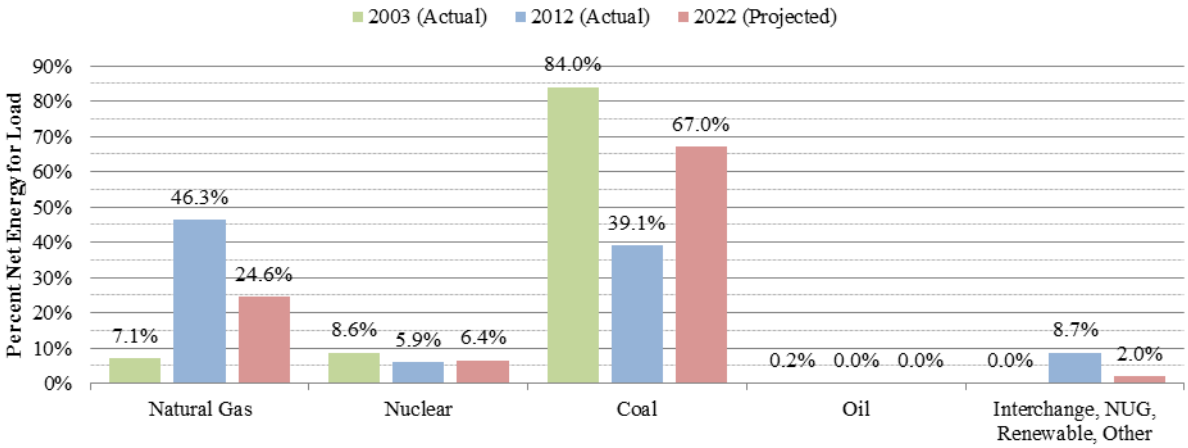
Source: 2013 TYSP Schedule 3

Generation Resources

Fuel Diversity

Figure 59 shows OUC's historic fuel mix for 2003 and 2012, and the projected fuel mix for 2022. Natural gas is the primary fuel on OUC's system in 2012, contributing 46.3 percent of system energy. This is projected to decline to under a quarter of system energy by 2022, with coal producing approximately two-thirds of system energy by the end of the planning period.

Figure 59: OUC - Fuel Diversity (History & Forecast)



Source: 2013 TYSP Schedule 6

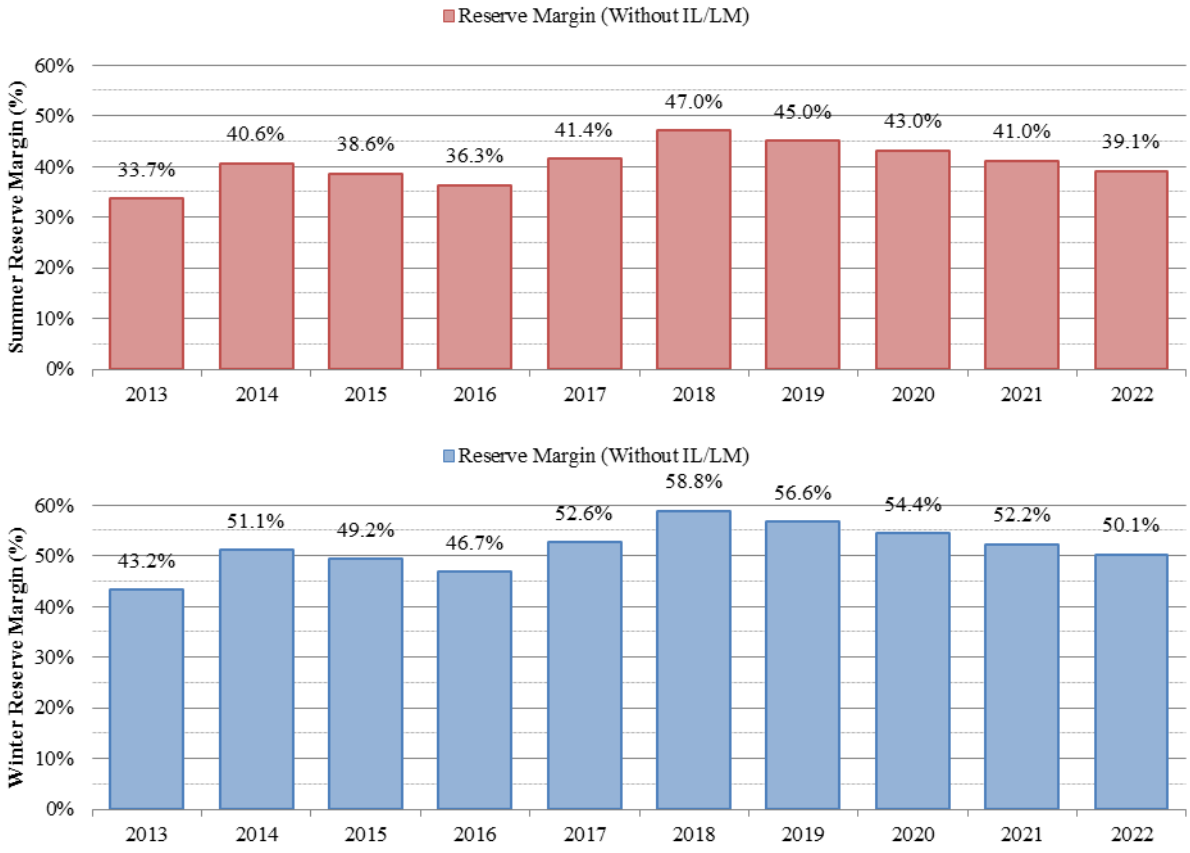
Planned Generation

OUC's 2013 TYSP did not contain any planned generation additions. This represents a decrease from the company's 2012 TYSP, which included a single combustion turbine.

Reserve Margin

OUC maintains a 15 percent reserve margin based on FRCC planning requirements. Figure 60 displays the forecasted planning reserve margin for OUC through the planning period for both seasons, including the effects of projected conservation activities. As shown in the figure, OUC is a summer-peaking utility and has sufficient reserve margin to meet projected customer demands for both seasons throughout the planning period.

Figure 60: OUC - Seasonal Reserve Margin (Summer & Winter)



Source: 2013 TYSP Schedule 7

Seminole Electric Cooperative (SEC)

SEC is a generation and transmission rural electric cooperative that serves only wholesale customers that purchase power from SEC under long-term wholesale power contracts, and is collectively the state's fourth largest TYSP utility. SEC is within the FRCC Region, with load serviced throughout the State of Florida. Its generation assets are primarily within the central region. As SEC is a rural electric cooperative, the Commission's regulatory authority is limited to safety, rate structure, territorial boundaries, bulk power supply, operations, and planning

Load and Energy Forecast

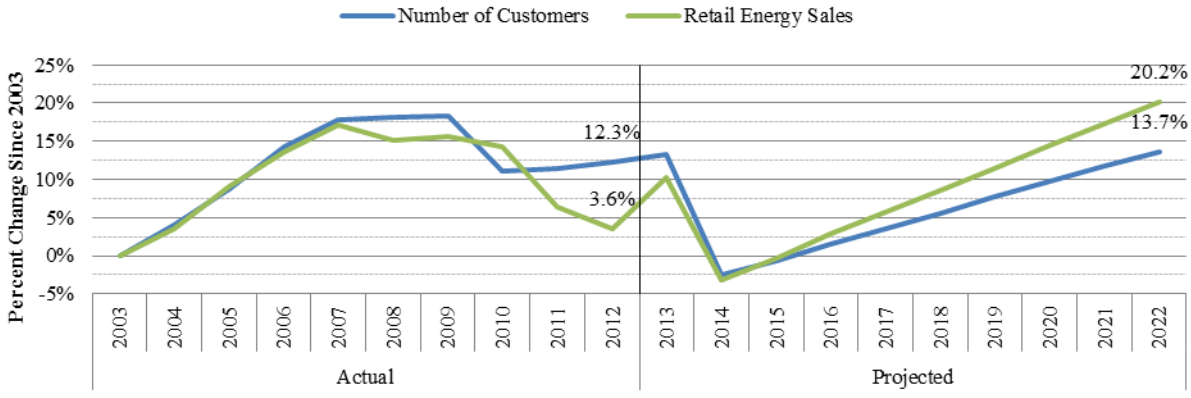
In 2012, SEC's members had approximately 850,000 customers, with annual retail energy sales of 14,387 GWh, or approximately 6.7 percent of the state of Florida's NEL. Total number of customers and annual energy consumption by customer class are below in Figure 61.

Figure 61: SEC - Number of Customers and Energy Usage by Class

Source: 2013 TYSP Schedule 2

Figure 62 illustrates the company's historic and projected growth as a percentage of its total number of customers and retail energy sales in 2003. Over the last ten years, SEC's member cooperatives had increased the number of customers by 12.3 percent and retail sales by 3.6 percent. The company forecasts a decline in 2014 due to the loss of Lee County Electric Cooperative, which will purchase power from FPL. but otherwise positive annual growth over the planning period, with retail energy sales exceeding the historic 2007 peak by 2021.

Figure 62: SEC - Customer and Retail Energy Sale Growth Since 2003

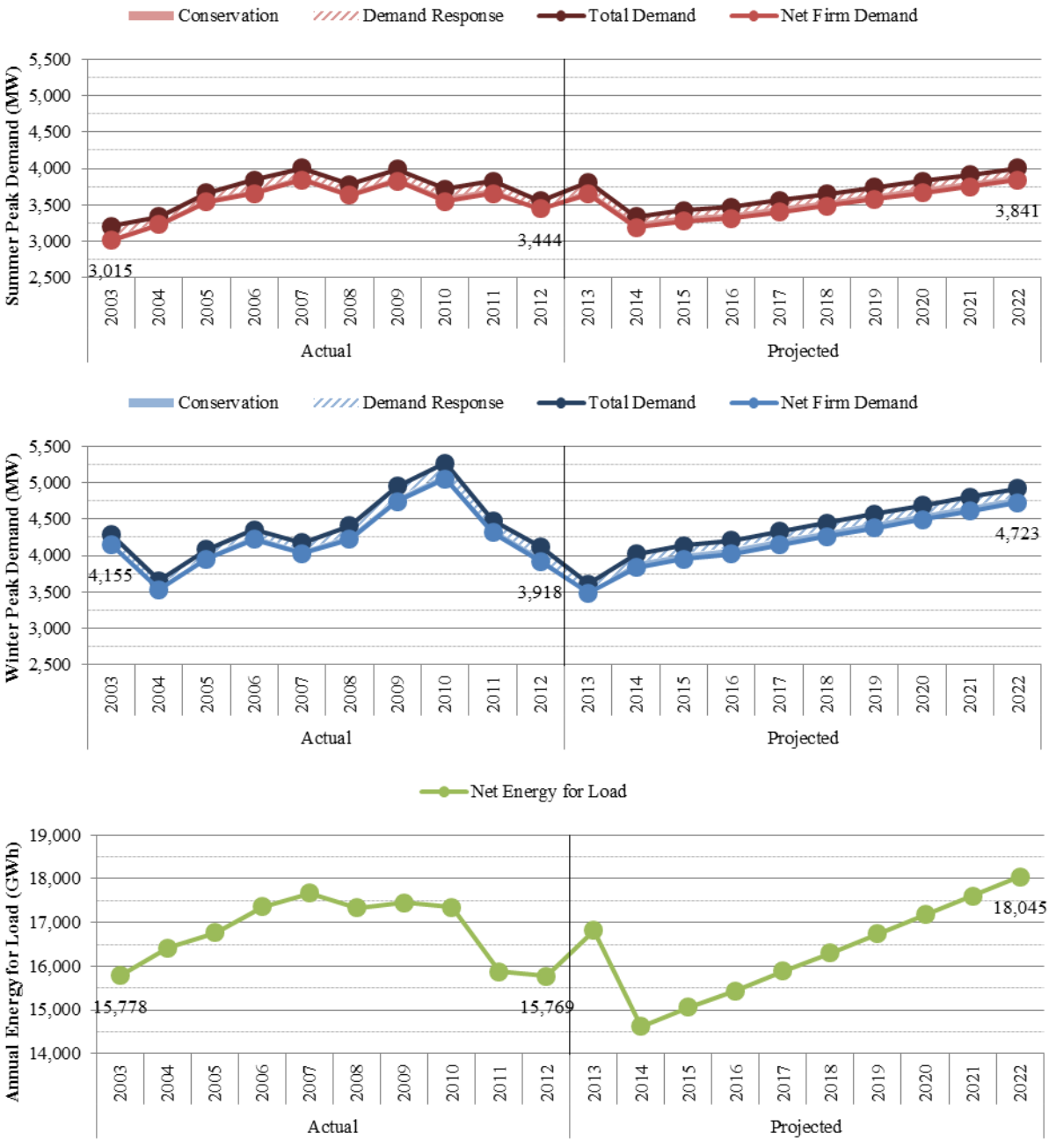


Source: 2013 TYSP Schedule 2

Seasonal Peak Demand & Annual Energy for Load

The following three graphs in Figure 63 show SEC's historic peak demand for both the summer and winter seasons, and net energy for load for the years 2003 through 2012. The forecasted values are also shown through the current planning horizon. Figure 63 below includes the effect of member cooperative's DSM programs.

Figure 63: SEC - Seasonal Peak Demand and Annual Energy Consumption (Historic & Forecast)



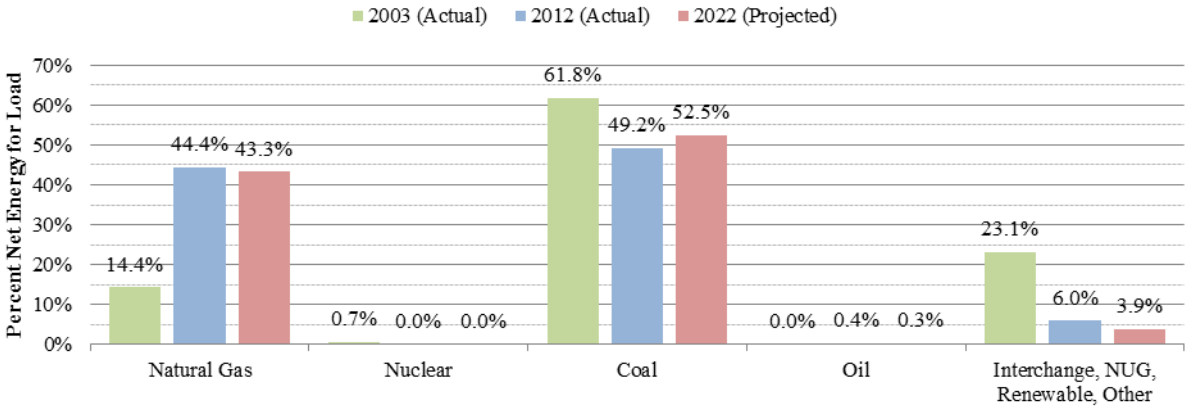
Source: 2013 TYSP Schedule 3

Generation Resources

Fuel Diversity

Figure 64 shows SEC's historic fuel mix for 2003 and 2012, and the projected fuel mix for 2022. SEC's primary generation fuel is coal, with 49.2 percent of system energy generated by coal. Coal usage has declined however, primarily with the increase of natural gas, which is the next highest fuel for SEC's system energy. Natural gas has risen to 44.4 percent of system energy in 2012, up from only 14.4 percent in 2003. Coal is anticipated to remain the main system fuel throughout the planning period, making up 52.5 percent in 2022, although natural gas is projected to increase its share of system energy to 43.3 percent in 2022.

Figure 64: SEC - Fuel Diversity (History & Forecast)



Source: 2013 TYSP Schedule 6

Planned Generation

SEC's 2013 TYSP includes a total of nine planned generating units, two combined cycles and seven combustion turbines. With the exception of one of the combined cycle units, all are to be sited at a location to be determined in Gilchrist County. The planned units are detailed below in Table 22. This represents a decrease in the number and total capacity of generation additions from the company's 2012 TYSP, which included three combined cycle units and nine combustion turbines.

Table 22: SEC - Planned Generation Additions

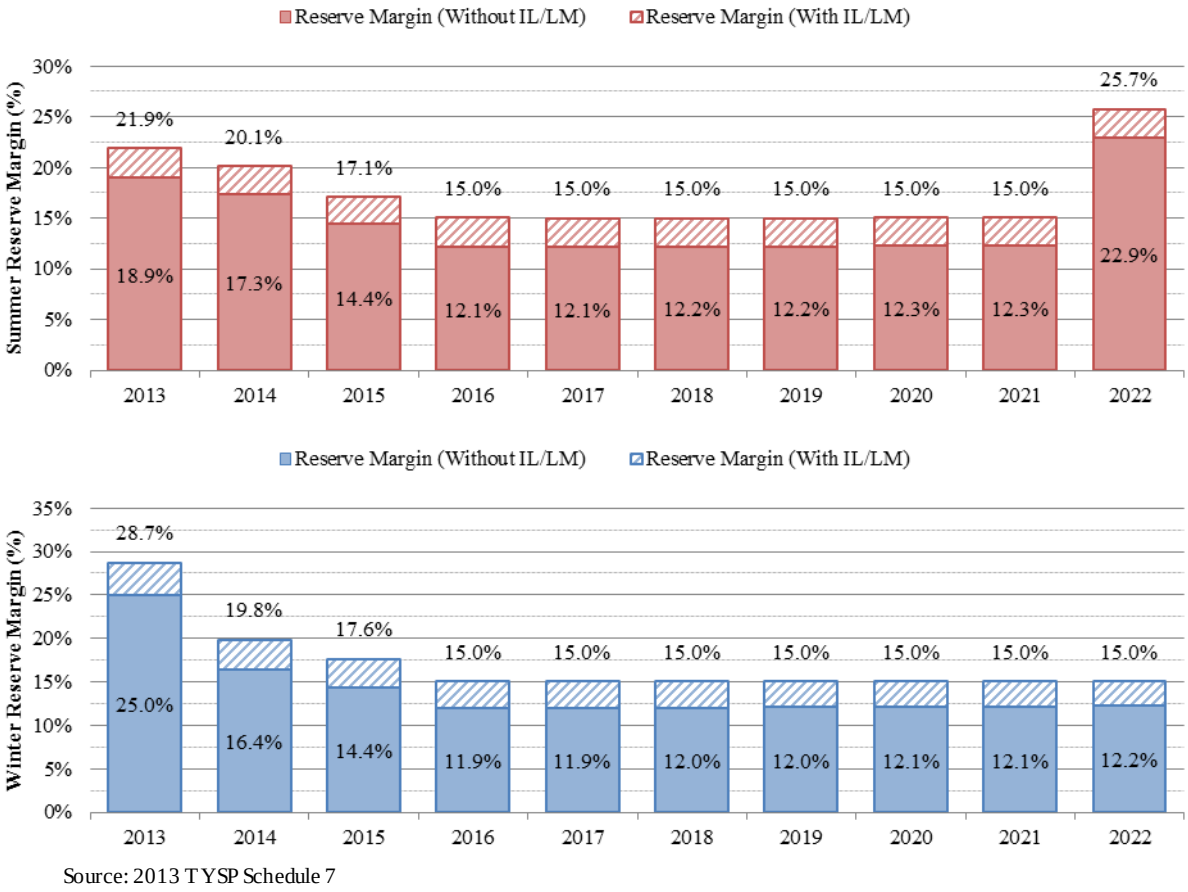
Generating Unit Name	Generator Type	Summer Capacity (MW)	In-Service Date	PPSA
Natural Gas Units				
Unnamed CT 1	Combustion Turbine	198	12/2019	N/A
Unnamed CC 1	Combined Cycle	192	12/2020	Required
Unnamed CC 2	Combined Cycle	192	12/2020	Required
Unnamed CT 2	Combustion Turbine	198	12/2020	N/A
Unnamed CT 3	Combustion Turbine	198	12/2020	N/A
Unnamed CT 4	Combustion Turbine	198	12/2021	N/A
Unnamed CT 5	Combustion Turbine	198	12/2021	N/A
Unnamed CT 6	Combustion Turbine	198	12/2021	N/A
Unnamed CT 7	Combustion Turbine	198	12/2021	N/A

Source: 2013 TYSP Schedule 8

Reserve Margin

SEC is within the FRCC region and is required to meet a 15 percent reserve margin requirement for planning purposes. Figure 65 displays the forecasted planning reserve margin for SEC through the planning period for both seasons, including the effects of projected conservation activities. The impact of demand response programs on reserve margin is also included. As shown in the figure, SEC has sufficient reserve margin to meet projected customer demands for both seasons throughout the period when including demand response.

Figure 65: SEC - Seasonal Reserve Margin (Summer & Winter)



Source: 2013 TYSP Schedule 7

City of Tallahassee Utilities (TAL)

TAL is a municipal utility, and the state's second smallest TYSP utility. The utility's service territory is within the FRCC region, in Leon County, and primarily serves the City of Tallahassee. As TAL is a municipal utility, the Commission's regulatory authority is limited to safety, rate structure, territorial boundaries, bulk power supply, operations, and planning.

Load and Energy Forecast

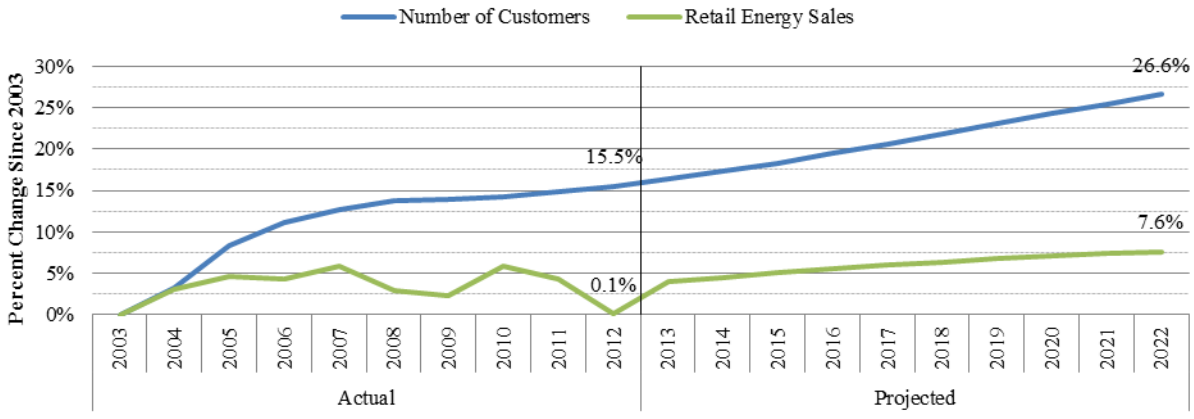
In 2012, TAL had approximately 115,000 customers, with annual retail energy sales of 2,604 GWh, or approximately 1.2 percent of the state of Florida's NEL. Total number of customers and annual energy consumption by customer class are below in Figure 66.

Figure 66: TAL - Number of Customers and Energy Usage by Class

Source: 2013 TYSP Schedule 2

Figure 67 illustrates the company's historic and projected growth as a percentage of its total number of customers and retail energy sales in 2003. Over the last ten years, TAL has increased its total number of customers by 15.5 percent, while only increasing retail energy sales by 0.1 percent. The company forecasts continued positive growth for the next ten years, with retail energy sales exceeding the historic 2007 peak by 2017.

Figure 67: TAL - Customer and Retail Energy Sale Growth Since 2003

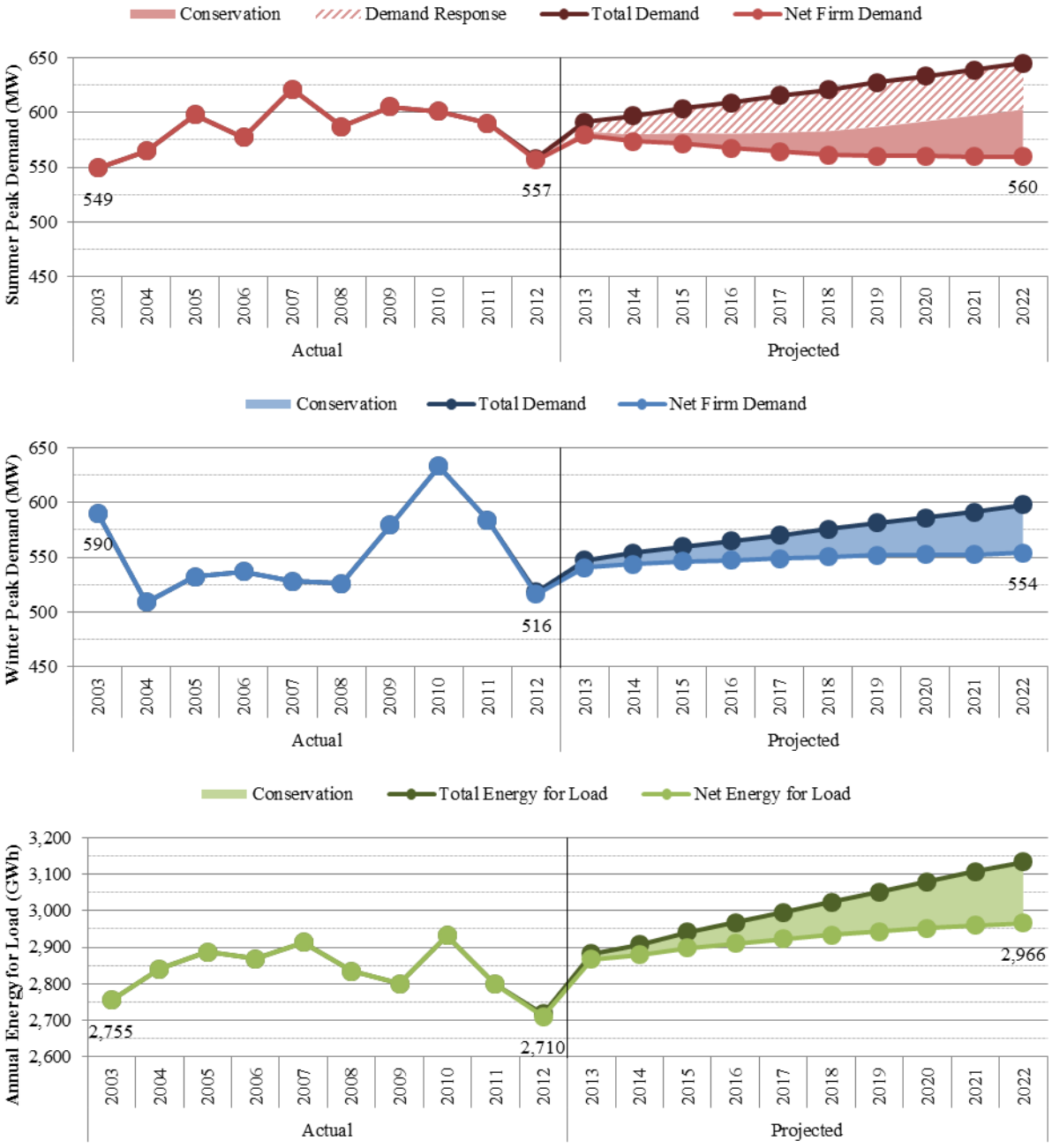


Source: 2013 TYSP Schedule 2

Seasonal Peak Demand & Annual Energy for Load

The following three graphs in Figure 68 show TAL's historic peak demand for both the summer and winter seasons, and net energy for load for the years 2003 through 2012. The forecasted values are also shown through the current planning horizon, including the effect of DSM. As seen below, TAL has a demand response program for summer peak demand, but not for the winter period.

Figure 68: TAL - Seasonal Peak Demand and Annual Energy Consumption (Historic & Forecast)



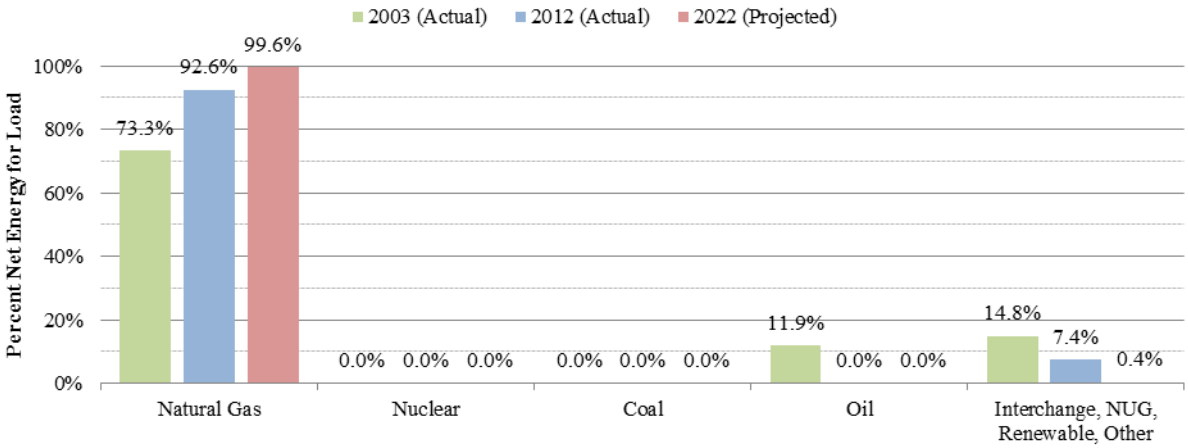
Source: 2013 TYSP Schedule 3

Generation Resources

Fuel Diversity

Figure 69 shows TAL's historic fuel mix for 2003 and 2012, and the projected fuel mix for 2022. TAL relies almost exclusively on natural gas for its generation, excluding some small amount of purchases from other utilities. This dependency is anticipated to remain throughout the planning period, with only natural gas-fired generation to be added, and purchases from other utilities forecasted to decrease.

Figure 69: TAL - Fuel Diversity (History & Forecast)



Source: 2013 TYSP Schedule 6

Planned Generation

TAL's 2013 TYSP includes a single generating unit addition at their existing Hopkins plant site in Leon County. The unit is detailed below in Table 23. This represents an increase over the company's 2012 TYSP, which included no generation additions.

Table 23: TAL - Planned Generation Additions

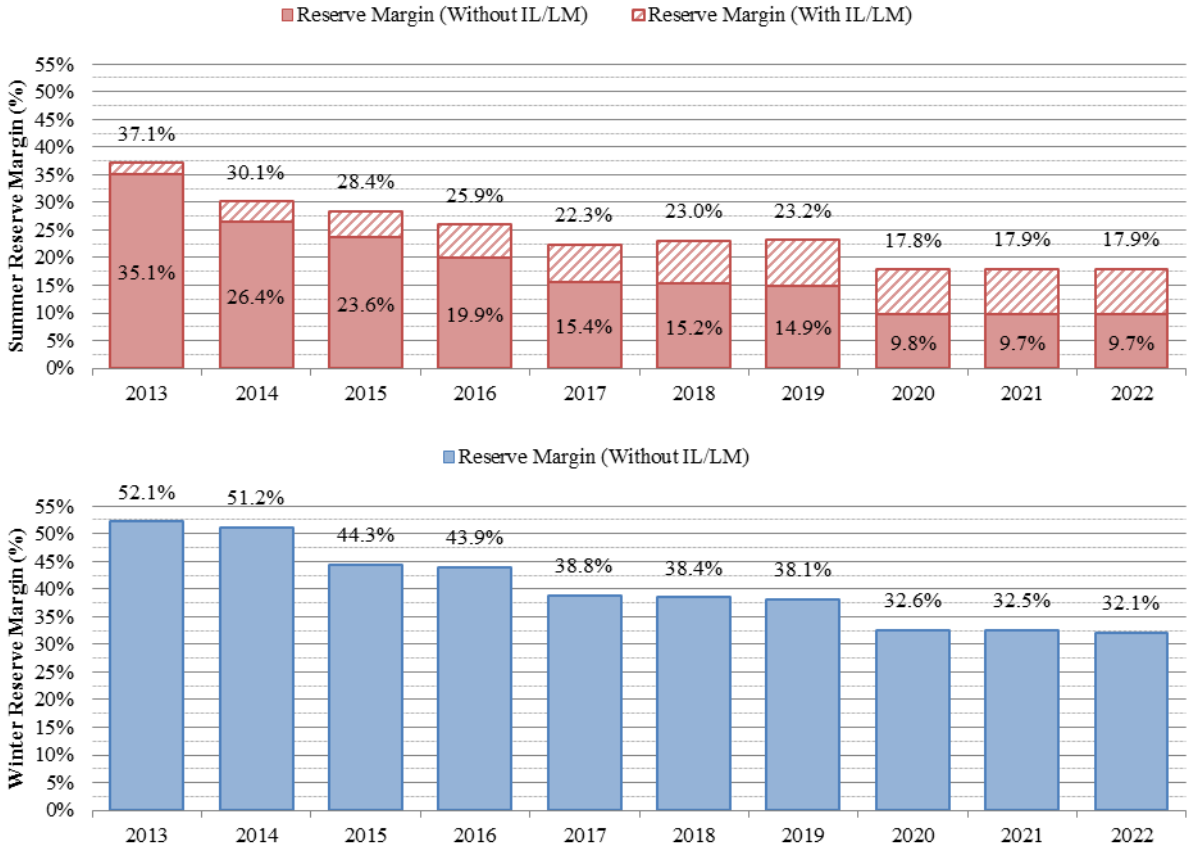
Generating Unit Name	Generator Type	Summer Capacity (MW)	In-Service Date	PPSA
Natural Gas Units				
Hopkins 5	Combustion Turbine	46	5/2020	N/A

Source: 2013 TYSP Schedule 8

Reserve Margin

TAL is within the FRCC region and is required to meet a 15 percent reserve margin requirement. However, TAL has adopted an 18 percent planning reserve margin requirement. Figure 70 displays the forecast planning reserve margin for TAL through the planning period for both seasons including the effects of projected conservation activities. The impact of the utility's demand response programs, which are focused on summer demand only, is also included in the summer reserve margin. As shown in the figure, TAL is a summer peaking utility and has sufficient reserve margin to meet projected customer demands throughout the period when including demand response.

Figure 70: TAL - Seasonal Reserve Margin (Summer & Winter)



Source: 2013 TYSP Schedule 7

Appendix A

Comments On The 2013 Ten-Year Site Plans For Florida's Electric Utilities

Florida Public Service Commission

Tallahassee, FL
October 2013

Ten-Year Site Plan Comments List

State Agencies

- Department of Economic Opportunity
- Department of Environmental Protection
- Department of Transportation

Regional Planning Councils

- Central Florida Regional Planning Council
- East Central Florida Regional Planning Council
- North Central Florida Regional Planning Council
- Northeast Florida Regional Planning Council
- Treasure Coast Regional Planning Council

Water Management Districts

- South Florida Water Management District
- Southwest Florida Water Management District
- St. John's River Water Management District
- Suwannee River Water Management District

Local Governments

- Citrus County

Other Organizations

- Sierra Club and Earthjustice

APPENDIX A

State Agencies

- Department of Economic Opportunity
- Department of Environmental Protection
- Department of Transportation

Rick Scott
GOVERNOR

FLORIDA DEPARTMENT of ECONOMIC OPPORTUNITY

Jesse Panuccio
EXECUTIVE DIRECTOR

July 18, 2013

Mr. Phillip Ellis
Engineering Specialist III
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, Florida 32399-0850

Dear Mr. Ellis:

At your request we have reviewed the 2013 Ten-Year Site Plans of the electric utilities. The Department of Economic Opportunity's review focused on potential sites for future power generation, and the compatibility of those sites with the applicable local comprehensive plan, including the adopted future land use map, adjacent land uses, and natural resources on or adjacent to the potential sites.

Our review of the 2013 Ten-Year Site Plans addressed ten potential power plant sites identified in the Ten-Year Site Plans of the following utilities: Florida Power & Light Company, Gulf Power Company, and Seminole Electric Cooperative. None of the potential sites were found to be incompatible with the applicable local comprehensive plan.

Should you have any questions regarding these comments, please call Scott Rogers, Planning Analyst, at (850) 717-8510, or by email at scott.rogers@deo.myflorida.com.

Sincerely,

Mike McDaniel
Comprehensive Planning Manager

MM/sr

Enclosure: Department Comments

2013 Ten-Year Site Plan Review

Three utilities, Gulf Power, Florida Power and Light, and Seminole Electric, have identified a total of ten potential sites for future power generation. Potential sites are identified in Rule 25-22.070, F.A.C., as "sites within the state that an electric utility is considering for possible location of a power plant, a power plant alteration, or an addition resulting in an increase in generating capacity." These sites are discussed below.

1. Gulf Power

In its Ten-Year Site Plan, Gulf Power stated it will consider four properties as potential sites for future generating facilities. Two potential sites contain existing power plants: Plant Crist site in Escambia County and Plant Smith Site in Bay County. Two potential sites are undeveloped: Caryville Site in Holmes and Washington Counties and North Escambia Site in Escambia County.

A. Plant Crist Site. This site, located in Escambia County, is designated Industrial and Agriculture on the adopted Future Land Use Map (FLUM). Electric power generation facilities are an allowed use in the Industrial category and may be allowed as a conditional use in Agriculture through the Land Development Code. The northern and eastern parts of the site are located in the coastal high hazard area and contain wetlands and 100-year floodplain. Adjacent land uses are Industrial, Conservation, Agriculture, and Mixed-Use Suburban.

For information regarding the location of the coastal high hazard area relative to the site, contact Julie Dennis with the Department of Economic Opportunity, Bureau of Comprehensive Planning, at (850) 717-8478. For wetland compatibility issues, contact the Department of Environmental Protection (DEP) Office of Submerged Lands and Environmental Resources at (850) 245-8474. For information on floodplain compatibility, contact the State of Florida Floodplain Management Office at (850) 413-9960.

B. Plant Smith Site. Located in Bay County, the Plant Smith site is adjacent to the North Bay area of St. Andrews Bay. The site is located in the Category 1, 2, 3 and 4 storm surge zones. It is designated Industrial and Conservation on the adopted FLUM. Public utilities are allowed uses in both Industrial and Conservation. Adjacent land uses are Agriculture-Timber and Conservation. Wetlands and 100-year floodplains are also located onsite.

For further information regarding the location of storm surge zones relative to the site, Gulf Power should contact Julie Dennis with the Department of Economic Opportunity, Bureau of Comprehensive Planning, at (850) 717-8478. For assistance with wetland compatibility issues, contact the DEP Office of Submerged Lands and Environmental Resources at (850) 245-8474. For information on floodplain compatibility, contact the State of Florida Floodplain Management Office at (850) 413-9960.

C. Caryville Site. The Caryville site is located in Holmes County, Washington County, and the City of Caryville, and it is adjacent to the Choctawhatchee River. The site is designated Agriculture in Holmes County, Agriculture/Silviculture in Washington County, and Agriculture and Conservation in Caryville. In all three jurisdictions, public utilities are allowed in areas designated Agriculture. The site is surrounded by agricultural land uses. Floodplain and wetland areas exist throughout the site.

Gulf Power should contact the following DEP offices for further information: (1) for compatibility with Outstanding Florida Waters, contact the Standards and Assessment section at (850) 245-8064; and (2) for wetland compatibility issues, contact the Office of Submerged Lands and Environmental Resources at (850) 245-8474. For information on floodplain compatibility, contact the State of Florida Floodplain Management Office at (850) 413-9960.

D. Northern Escambia Site. The site is located in northern Escambia County, approximately five miles southwest of the City of Century and west of the Escambia River. The Escambia County Future Land Use Map designates the site predominantly as Agriculture with a very small part designated as Rural Community. Electric power generation facilities may be allowed as a conditional use in Agriculture and Rural Community through the land development code. The site is surrounded predominantly by Agriculture future land uses and a small area of Rural Community. The site and surrounding area are primarily used for timber harvesting and agricultural use, and the site is in close proximity to transmission, natural gas pipelines, railroad, major highways and access to water. The site contains a substantial amount of uplands with some wetlands, and Mitchell Creek that traverses the site.

For information regarding wetland compatibility issues, contact the Department of Environmental Protection Office of Submerged Lands and Environmental Resources at (850) 245-8474.

2. Florida Power and Light. Florida Power and Light (FPL) has identified five potential sites as described below.

A. Babcock Ranch, Charlotte County. This site is designated Babcock Ranch Overlay District (BROD) on the FLUM. The Development Order for the Babcock Ranch Development of Regional Impact (DRI) identifies this site as a Primary Active Greenway approved for the placement of solar generating facilities. Adjacent land uses to the east, west and south are also BROD. Land north of the site is designated Resource Conservation. The BROD is being developed under a cohesive set of policies, guided by the County's comprehensive plan, through the Master Incremental DRI process. No environmental or other compatibility issues have been identified for this site.

B. DeSoto Solar Expansion, DeSoto County. This site is designated Electrical Generating Facility on the County's adopted Future Land Use Map. The surrounding FLUM designations are Electrical Generating Facility and Rural/Agriculture. The site has been disturbed as a result of agricultural activities on the property. The site is adjacent to an existing transportation corridor

with roadway capacity. Demands on water facilities have already been considered in the growth projections of the County's comprehensive plan. No environmental or other compatibility issues have been identified for this site.

C. Manatee Plan site, Manatee County. This site is designated Public/Semipublic-2 on the adopted FLUM. Power generating facilities are an allowed use in this FLUM category. Adjacent uses are Public/Semipublic-2 and Agricultural-Rural. The site is also adjacent to Lake Parrish, which provides water to the existing power facility. Much of the property is disturbed due to agricultural activities onsite. No environmental or other compatibility issues have been identified for this site.

D. Martin County site. FPL is currently evaluating potential sites in Martin County for a future solar facility. No specific locations have been selected. The County's adopted comprehensive plan contains provisions for siting power generating facilities which use renewable energy sources. Future Land Use Policy 4.8C.1 allows alternative energy facilities in appropriate zoning districts. The policy states that "As the technology for wind, solar and other forms of power generation advance, the Land Development Regulations shall be revised to permit different forms of power generation in appropriate zoning districts." Policy 4.13A.12, which addresses the Public Utilities future land use category, states that "electrical power facilities solely utilizing solar, wind or other renewable energy fuel or energy source may be permitted in any other Future Land Use Designation, consistent with the Land Development Regulations."

For assistance with wetland compatibility issues, FPL should contact the Office of Submerged Lands and Environmental Resources at (850) 245-8474. For information on floodplain compatibility, contact the State of Florida Floodplain Management Office at (850) 413-9960.

E. Putnam County site. FPL is currently evaluating potential sites in Putnam County for a future solar facility or natural gas-powered facility. No specific locations have been identified. Sites currently under investigation are approximately 2,800 acres in area. The Industrial and Community Facilities and Services land use categories allow electrical generating plants. The County's Comprehensive Plan contains policies that address compatibility and suitability of land uses, as well as directing development away from environmentally sensitive lands.

3. Seminole Electric.

Seminole Electric has identified one site, a 350-acre parcel located northeast of the City Bell in Gilchrist County, as a potential power plant site. Much of the site has been used for silviculture (pine plantation) and consists of large tracts of planted longleaf and slash pine community. The site is designated Agricultural on the adopted Future Land Use Map. Electric generating facilities may be permitted as a special use in areas designated Agricultural. Issues that would be considered by the County through the special use review process include the amount of water projected to be used by the facility, the impact of water use on agricultural activities, and the impact of the facility on natural resources, including aquifer recharge areas and wetlands. The Gilchrist parcel is located near the Wacasassa Flats, a 50,000-acre high quality wetlands-to-

uplands ecosystem located in the middle of the County. Wacasassa Flats is a perched water table system that provides significant water storage, water filtering and wildlife habitat.

For assistance with wetland compatibility issues, Seminole Electric should contact the Office of Submerged Lands and Environmental Resources at (850) 245-8474. For information on floodplain compatibility, contact the State of Florida Floodplain Management Office at (850) 413-9960.

4. Utilities With No Potential Sites Identified in the TYSP: The following utilities identified no potential sites in their TYSPs: Gainesville Regional Utilities, Progress Energy Florida, Lakeland Electric, City of Tallahassee, Florida Municipal Power Agency, Tampa Electric Company, JEA, and Orlando Utilities Commission.

From: Bull, Robert
To: Phillip Ellis
Cc: Mulkey, Cindy
Subject: DEP Siting Coordination Office Ten Year Site Plan Review
Date: Monday, July 22, 2013 10:57:45 AM

The Department of Environmental Protection's Siting Coordination Office (SCO) has reviewed the 2013 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. If you have any questions for our office, feel free to contact me.

Thank you,

Bobby Bull, P.E.
Florida Department of Environmental Protection
Siting Coordination Office
2600 Blairstone Road, MS 5500
Tallahassee, FL 32399-2400
robert.bull@dep.state.fl.us
850/717-9111

Florida Department of Transportation

RICK SCOTT
GOVERNOR

605 Suwannee Street
Tallahassee, FL 32399-0450

ANANTH PRASAD, P.E.
SECRETARY

June 26, 2013

Phillip Ellis
Division of Regulatory Analysis
Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, FL 32399-0850

Dear Mr. Ellis:

The Siting Coordination Office has reviewed the ten-year site plans and find these are suitable as planning documents. If you have any questions please feel free to call me at (850)414-4572.

Sincerely,

Connie Mitchell
Siting Coordination Office

APPENDIX A

Regional Planning Councils

- Central Florida Regional Planning Council
- East Central Florida Regional Planning Council
- North Central Florida Regional Planning Council
- Northeast Florida Regional Planning Council
- Treasure Coast Regional Planning Council

CFRPC SERVING THE COUNTIES OF • DESOTO • HARDEE • HIGHLANDS • OKEECHOBEE • POLK

August 1, 2013

Phillip Ellis
State of Florida Public Service Commission
Capital Circle Office Center
2540 Shumard Oak Blvd
Tallahassee, FL 32399

Dear Mr. Ellis,

RE: Review of 2013 Ten-Year Site Plans for Florida's Electric Utilities

The CFRPC reviewed ten year site plans from Lakeland Electric, Orlando Utilities Commission, Progress Energy Florida, Tampa Electric Company, and Seminole Electric Cooperative as included on the Public Service Commission's website. As requested in the letter dated May 21, 2013, a brief summary and comments related to the suitability of the above mentioned plans as planning documents is below.

Lakeland Electric:

The plan states that there are no planned facilities for the 10-year planning reporting period. There are also no upgrades of existing facilities planned.

This document is suitable for a planning document at a regional level because it provides insight on the development of areas within a portion of the region through current demand and forecast demand. It also is helpful to know what energy conservation and management programs are being utilized as well as the environmental and land impacts are predicted to occur for the overall planning of the region's growth and development and protection.

This document is also written in a manner that makes it easy for non-utility planners to understand. However, due to the scanning or production process, the figures included in the document are blurry and very hard to read.

Orlando Utilities Commission:

According to the plan, no facilities are planned within the Central Florida Regional Planning Council Region for the 10-year planning reporting period. The plan discusses upgrades of existing facilities. Unfortunately, since there is not a map included to show where these facilities are located, it is not possible to determine which of them may be in the region.

Phillip Ellis
State of Florida Public Service Commission
Capital Circle Office Center
2540 Shumard Oak Blvd
Tallahassee, FL 32399

This document is suitable for a planning document at a regional level because it provides information as to facilities located within the region. It is somewhat less suitable as a planning document at providing insight on the development through current demand and forecast demand because it cannot be extrapolated to a regional or county level the document does not provide clear information on the areas. This document would also be more helpful as a planning document with the inclusion of a service area map.

Progress Energy Florida, Inc:

According to the plan, no facilities are planned within the Central Florida Regional Planning Council Region for the 10-year planning reporting period. However, two facilities are estimated to be put in cold stand by or retired by 2016. There are also no upgrades of existing facilities planned in these areas.

This document is suitable for a planning document at a regional level because it provides information as to the proposed locations of planned new facilities. It is somewhat less suitable as a planning document at providing insight on the development through current demand and forecast demand because it cannot be extrapolated to a regional or county level because Progress Energy's boundaries cover so much of the State of Florida. It is helpful to know what energy conservation and management programs are being utilized as well as the environmental and land impacts are predicted to occur for the overall planning of the region's growth and development and protection.

Seminole Electric Cooperative:

According to the plan, no facilities are planned within the Central Florida Regional Planning Council Region for the 10-year planning reporting period. There are also no upgrades of existing facilities planned in these areas.

This document is suitable for a planning document at a regional level because it provides information as to facilities located within the region. It is somewhat less suitable as a planning document at providing insight on the development through current demand and forecast demand because it cannot be extrapolated to a regional or county level because Seminole Electric Cooperative services so much of the State of Florida.

Tampa Electric Company:

Phillip Ellis
State of Florida Public Service Commission
Capital Circle Office Center
2540 Shumard Oak Blvd
Tallahassee, FL 32399

According to the plan, no facilities are planned within the Central Florida Regional Planning Council Region for the 10-year planning reporting period. However, there is a planned expansion at the Polk Power Station in Polk County. In addition, there is mention of a possible fuel conversion to biodiesel at the Phillips Station located in Highlands County, which was placed in long term reserve standby in 2009.

This document is suitable for a planning document at a regional level because it provides information as to the proposed locations of planned new expansions and because it provides insight on the development of areas within a portion of the region through current demand and forecast demand. It also is helpful to know what energy conservation and management programs are being utilized as well as the environmental and land impacts are predicted to occur for the overall planning of the region's growth and development and protection.

The proposed expansions/potential sitings as identified in the ten year power plant plans as submitted are consistent with the Central Florida Regional Planning Council Strategic Regional Policy Plan (SRPP). Thank you for the opportunity to review these electric utility ten year site plans.

Sincerely,

Marisa M. Barmby, AICP
Senior Planner

East Central Florida Regional Planning Council

309 Cranes Roost Blvd. Suite 2000, Altamonte Springs, FL 32701
Phone 407.262.7772 • Fax 407.262.7788 • www.ecfrpc.org

Hugh W. Harling, Jr. P.E.
Executive Director

MEMORANDUM

To: Phillip Ellis, Florida Public Service Commission

From: Hugh W. Harling, Jr., Executive Director
Tara M. McCue, AICP, Director of Planning and Community Design

Date: August 1, 2013

Subject: 2013 Ten-Year Site Plans Review
- Florida Power and Light
- Orlando Utilities Commission
- Progress Energy

The East Central Florida Regional Planning Council staff has completed a review of the 2013 Ten-Year Site Plans for the agencies listed above. Staff comments to each utility are italicized below.

Florida Power and Light (FPL)
Staff finds the document to be suitable for planning purposes. Council staff will provide further comments on environmental and regional impacts when new or modified units, projects or transmission lines are proposed and additional data and information are provided.

Orlando Utilities Commission (OUC)
Staff finds the document to be suitable for planning purposes. Council staff will provide further comments on environmental and regional impacts when new or modified units, projects or transmission lines are proposed and additional data and information are provided.

Progress Energy Florida (PEF)
Staff finds the document to be suitable for planning purposes. Council staff will provide further comments on environmental and regional impacts when new or modified units, projects or transmission lines are proposed and additional data and information are provided.

If you require any further information or comments, please contact Tara McCue, AICP at tara@ecfrpc.org or by phone at (407) 262-7772

North Central Florida Regional Planning Council

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2009 NW 67th Place, Gainesville, FL 32653-1603 • 352.955.2200

July 16, 2013

Mr. Phillip Ellis
Division of Regulatory Analysis
Florida Public Service Commission
Capitol Circle Office Center
2540 Shumard Oak Blvd
Tallahassee, FL 32399-0850

RE: Regional Review of Ten-Year Site Plan, 2013 - 2022
Seminole Electric Cooperative, Inc.

Dear Mr. Ellis:

Pursuant to Section 186.801, Florida Statutes, Council staff has reviewed the proposed Ten-Year Site Plan and provides the following comments.

The above-referenced ten-year site plan proposes to construct eight natural gas-powered electrical generation stations by 2022 to be located within Gilchrist County. The combined summer electrical generating capacity of the stations will be 1,770 megawatts, while the combined winter electrical generating capacity of the stations will be 2,080 megawatts. The ten-year site plan notes that 385 megawatts of the summer generating capacity and 456 megawatts of the winter generating capacity will be cooled by water using wet cooling towers with forced air draft fans.

The subject property of the Gilchrist County site is located adjacent to Waccasassa Flats, a Natural Resource of Regional Significance as identified and mapped in the North Central Florida Strategic Regional Policy Plan. Page IV-55 of the North Central Florida Strategic Regional Policy Plan notes the following regarding Waccasassa Flats.

> Occupying approximately 61,653 acres, Waccasassa Flats runs down the center of Gilchrist County. The flats are part of a larger wetland system which runs into Levy County and the Withlacoochee Regional Planning District. During the rainy season, waters in the aquifer build up sufficient pressure to spill out of the many sinkholes and ponds scattered throughout the flats to inundate the area.
>
> The area is predominantly comprised of commercial pine plantation. Pine stands are interspersed among numerous cypress ponds, depression marshes, hydric hammock, and other wetland communities. Several lakes (the largest of which is 150 acres), small areas of upland hardwood forest, sandhill, and other minor natural communities contribute to the diversity of the flats.

Applicable regional plan goals and policies include the following:

> REGIONAL GOAL 4.7. Maintain the quantity and quality of the region's surface water systems in recognition of their importance to the continued growth and development of the region.

Policy 4.7.5. Use non-structural water management controls as the preferred water management approach for rivers, lakes, springs, and fresh water wetlands identified as natural resources of regional significance.

Policy 4.7.6. Support the coordination of land use and water resources planning for surface water resources designated as natural resources of regional significance among the Council, local governments, and the water management districts through regional review responsibilities, participation in committees and study groups, and ongoing communication.

Policy 4.7.12. Ensure that local government comprehensive plans, DRIs, and requests for federal and state funds for development activities reviewed by the Council include adequate provisions for stormwater management, including retrofit programs for known surface water runoff problem areas, and aquifer recharge protection in order to protect the quality and quantity of water contained in the Floridan Aquifer and surface water systems identified as natural resources of regional significance.

Policy 4.7.13. Work with local governments, state and federal agencies, and the local water management districts in the review of local government comprehensive plans and developments of regional impact as they affect wetlands identified as natural resources of regional significance to ensure that any potential adverse impacts created by the proposed activities on wetlands are minimized to the greatest extent possible.

The proposed electrical power generation site to be located in Gilchrist County will be consistent with the regional plan provided the water consumption of the electrical generating stations does not result in significant and adverse impacts to the wetland functions of Wacassassa Flats. However, the ten-year site plan does not indicate the water source or the amount of water to be used to cool the electrical generating stations. Additionally, the ten-year site plan does not provide an analysis of environmental impacts to Wacassassa Flats of the withdrawal of groundwater used to cool the electrical generating units.

Therefore, it is recommended that the ten-year site plan include information on the water consumption of the electrical generating stations as well as an analysis of environmental impacts to Wacassassa Flats as a result of their water consumption. Finally, it is recommended that an alternative environmental impact analysis be provided whereby 100 percent of the electrical generation capacity of the site is cooled using air.

If you have any questions concerning this matter, please do not hesitate to contact Steven Dopp, Senior Planner of the Planning Council's Regional and Local Government Programs staff, at 352.955.2200, extension 109.

Sincerely,

Scott R. Koons, AICP
Executive Director

v:\chouse\responses\2012-13_60-docx

North Central Florida Regional Planning Council

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REGIONAL CLEARINGHOUSE
INTERGOVERNMENTAL COORDINATION AND RESPONSE

Date: 7-16-13

PROJECT DESCRIPTION

#60 - Seminole Electric Cooperative, Inc., Ten-Year Site Plan 2013 -2022

TO: Mr. Phillip Ellis
Division of Regulatory Analysis
Florida Public Service Commission
Capitol Circle Office Center
2540 Shumard Oak Blvd
Tallahassee, FL 32399-0850

_X_ COMMENTS ATTACHED

___ NO COMMENTS REGARDING THIS PROJECT

IF YOU HAVE ANY QUESTIONS REGARDING THESE COMMENTS, PLEASE CONTACT STEVEN DOPP, SENIOR PLANNER, AT THE NORTH CENTRAL FLORIDA REGIONAL PLANNING COUNCIL AT (352) 955-2200 OR SUNCOM 625-2200, EXT 109

APPENDIX A

North Central Florida Regional Planning Council

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REGIONAL CLEARINGHOUSE
INTERGOVERNMENTAL COORDINATION AND RESPONSE

Date: 7-16-13

PROJECT DESCRIPTION

#58 - Progress Energy Florida, Inc. Ten-Year Site Plan, 2013 - 2023

TO: Mr. Phillip Ellis
Division of Regulatory Analysis
Florida Public Service Commission
540 Shumard Oak Blvd.
Tallahassee, FL 32399-0850

___ **COMMENTS ATTACHED**

__X__ **NO COMMENTS REGARDING THIS PROJECT**

IF YOU HAVE ANY QUESTIONS REGARDING THESE COMMENTS, PLEASE CONTACT STEVEN DOPP, SENIOR PLANNER, AT THE NORTH CENTRAL FLORIDA REGIONAL PLANNING COUNCIL AT (352) 955-2200 OR SUNCOM 625-2200, EXT 109

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REGIONAL CLEARINGHOUSE
INTERGOVERNMENTAL COORDINATION AND RESPONSE

Date: 7-16-13

PROJECT DESCRIPTION

#59 - Gainesville Regional Utilities - 2013 Ten-Year Site Plan

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TO: Mr. Phillip Ellis
Division of Regulatory Analysis
Florida Public Service Commission
540 Shumard Oak Blvd.
Tallahassee, FL 32399-0850

___ **COMMENTS ATTACHED**

_X_ **NO COMMENTS REGARDING THIS PROJECT**

IF YOU HAVE ANY QUESTIONS REGARDING THESE COMMENTS, PLEASE CONTACT STEVEN DOPP, SENIOR PLANNER, AT THE NORTH CENTRAL FLORIDA REGIONAL PLANNING COUNCIL AT (352) 955-2200 OR SUNCOM 625-2200, EXT 109

Northeast Florida Regional Council

Bringing Communities Together

Baker • Clay • Duval • Flagler • Nassau • Putnam • St. Johns

June 7, 2013

Ms. Jeanette Sickel
Florida Public Service Commission
Division of Economic Regulation
2540 Shumard Oak Blvd.
Tallahassee, FL 32399-0850

Dear Ms. Sickel:

Please find attached the Northeast Florida Regional Council's review for JEA's ten-year site plan.

JEA Ten-year Site Plan: The ten-year site plan, as required by Section 186.801 of the Florida Statutes (F.S.), was reviewed by the Northeast Florida Regional Council staff.

> ***Action taken:*** Staff's review was approved by the Council and authorized for transmittal to the Florida Public Service Commission.

If you have any further requests or questions, please contact Ms. Ameera Sayeed, Senior Regional Planner, (904) 279-0885, ext. 151 or asayeed@nefrc.org.

Sincerely,

Edward Lehman
Director of Planning & Development

Attachment

EL/ag

RECEIVED
JUN 21 2013
BY:

6850 Belfort Oaks Place • Jacksonville, FL 32216 • (904) 279-0880 • Fax (904) 279-0881 • Suncom 874-0880 • Suncom Fax 874-0881
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MEMORANDUM

DATE: May 31, 2013

TO: Northeast Florida Regional Council

THRU: Planning and Growth Management Policy Committee

FROM: Ameera F. Sayeed, GISP, Senior Regional Planner

RE: Review of JEA Ten-Year Power Plant Site Plan 2013-2022

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. The purpose of the ten-year site plan is to disclose the general location of proposed power plant sites and facilitate coordinated planning efforts. Pursuant to Section 186, Florida Statues, Council staff reviewed the most recent ten-year site plan prepared by the Jacksonville Electric Authority (JEA). The purpose of this report is to summarize JEA's plans for future power generation and provide comments for transmittal to the Florida Public Service Commission (Commission).

Statutory Authority

Section 186.801, Florida Statutes, requires that all major generating electric utilities in Florida submit a *Ten-Year Site Plan* to the Commission for review. Each *Ten-Year Site Plan* contains projections of the utility's electric power needs for the next ten years and the general location of proposed power plant sites and major transmission facilities. In accordance with the statute, the Commission performs a preliminary study of each *Ten-Year Site Plan* and must determine whether it is "suitable" or "unsuitable". In conducting its review, the Commission considers the views of appropriate local and state agencies. The Northeast Florida Regional Council reviews electric utility Ten-Year Site Plans within the region and submits comments to the Commission for review. The Commission forwards the *Ten-Year Site Plan* review, upon completion, to the Florida Department of Environmental Protection (DEP) for use in subsequent power plant siting proceedings. To fulfill the requirements of Section 186.801, Florida Statutes, the Commission has adopted Rules 25-22.070 through 25-22.072, Florida Administrative Code. Electric utilities must file the *Ten-Year Site Plan* by April 1st.

Board Memorandum
May 31, 2013

Purpose
The intent of the *Ten-Year Site Plans* is to give state, regional, and local agencies advance notice of proposed power plants and transmission facilities. However, the *Ten-Year Site Plans* are not a binding plan of action on electric utilities. As such, the Commission's classification of a *Ten-Year Site Plan* as suitable or unsuitable has no binding effect on the utility. Such a classification 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. Because the *Ten-Year Site Plans* are planning documents containing tentative data, they may not contain sufficient information to allow regional planning councils, water management districts, and other reviewing agencies to evaluate site-specific issues within their jurisdictions. Each utility is responsible for providing detailed data, based on in-depth environmental assessments, during Power Plant Siting Act or Transmission Line Siting Act certification proceedings.

Summary of the Plan
JEA is the seventh largest municipally owned electric utility in the United States in terms of number of customers. JEA's electric service area covers most of Duval County and portions of Clay and St. Johns counties. JEA's service area covers approximately 900 square miles and serves approximately 420,000 customers. The evaluation has revealed that JEA has included in this ten-year plan the necessary analysis. The existing JEA electric supply resources, forecasts of customer energy requirements and peak demands, forecasts of fuel process and availability, and an analysis of alternatives for resources that would meet JEA's future capacity and energy needs were reported in the ten-year plan. JEA forecasts accounted for the system peak demand growth and energy consumption resource plan; in addition to cost considerations, environmental and land use considerations were amply factored into the ten-year plan. JEA had provided population estimates in previous ten-year site plans and it appears that the current plan no longer includes the population forecast and accompanying discussion.

JEA consists of three separate entities: The JEA Electric system, the St. Johns River Power Park and the Robert W. Scherer system. Collectively, these plants consist of two dual-fired (petroleum coke/coal) Circulating Fluidized Bed steam turbine-generator units (Northside steam Units 1 and 2); one dual-fired (oil/gas) steam turbine-generator unit (Northside steam Unit 3); five dual-fired (gas/diesel) combustion turbine-generator units (Kennedy GT1 and GT8, and Brandy Branch GT1, CT2, and CT3); two natural gas-fired combustion turbine-generator units (GEC GT1 and GT2); four diesel-fired combustion turbine-generator units (Northside GTs 3, 4, 5, and 6); and one combined cycle heat recovery steam generator unit (Brandy Branch steam Unit 4). The St. Johns River Power Park (SJRPP) is jointly owned by JEA (80 percent) and Florida Power and Light (FPL) (20 percent). SJRPP consists of two nominal 638 MW bituminous coal fired units located north of the Northside Generating Station in Jacksonville, Florida.

Nuclear Generation
In March 2008, JEA approved the policy of pursuing nuclear energy partnerships with the goal of providing 10 percent of JEA's power from nuclear sources. In June 2008, JEA entered into a purchase power agreement with the Municipal Electric Authority of Georgia (MEAG) for a portion of MEAG's entitlement to the Vogtle Units 3 and 4, which are proposed new nuclear units. These two new nuclear units are under construction at the existing Plant Vogtle location in

Burke County, GA. JEA is entitled to net firm capacity of 206 MW from the proposed units. JEA assumes they will have available capacity beginning in the year 2017 from Unit 3 and additional capacity from Unit 4 beginning in the year 2018.

Clean Power and Renewable Energy
JEA has pursued several clean power initiatives and is in the process of evaluating potential renewable energy resources. JEA has worked with the Sierra Club of Northeast Florida, the American Lung Association and local environmental groups to establish a process to maintain an action plan entitled "Clean Power Action Plan". This Plan includes an advisory Panel that is comprised of community representatives. Also, JEA has included in their review and planning installation of solar photovoltaic, solar thermal, landfill and wastewater treatment biogas capacity and wind capacity. Progress has extended to include installation of clean power systems, unit efficiency improvements, commitment to purchase power agreements (including nuclear power), legislative and public education activities, and research into and development of clean power technologies.

Solar
JEA has installed 35 solar PV systems, totaling 222 kW, on public high schools in Duval County, as well as many of JEA's facilities, and the Jacksonville International Airport. JEA implemented the Solar Incentive Program in early 2002. This program continues to provide rebates for the installation of solar thermal systems. In addition to the solar thermal system incentive program, JEA established a residential net metering program to encourage the use of customer-sited solar PV systems, which was revised as the Tier 1 & 2 Net Metering policy in 2009, to include all customer-owned renewable generation systems up to and equal to 100 kW. In 2011, JEA established the Tier 3 Net Metering Policy for customer-owned renewable generation systems greater than 100 kW up to 2 MW. JEA signed a purchase power agreement with Jacksonville Solar, LLC in May 2009 to provide energy from a 15.0 MW DC rated solar farm, which began operation in summer 2010.

Landfill
JEA owns three internal combustion engine generators that are fueled by the methane gas produced by the landfill. JEA also receives landfill gas from the North landfill, which is fed to the Northside Generating Station and is used to generate power at Northside Unit 3.

Wind
JEA purchases 10MW of wind capacity from NPPD's (Nebraska Public Power District) and in turn the NPPD buys back the energy at specified on/off peak charges. JEA receives environmental credits associated with green projects. JEA entered into a 20-year agreement with Nebraska Public Power District to continue to participate in the wind generation project located in Ainsworth, Nebraska.

Biomass
JEA owns three internal combustion engine generators located at the Girvin Road landfill. This facility was placed into service in July 1997, and is fueled by the methane gas produced by the landfill. The facility originally had four generators, with an aggregate net capacity of 3 MW. Gas

generation has declined, and one generator was removed and placed into service at the Buckman Wastewater Treatment facility.

In 2011, JEA started a co-firing biomass in the Northside Units 1 and 2, utilizing wood chips from JEA tree trimming activities as a biomass energy source. Northside 1 and 2 has produced a total of 2,154 MWh of energy from wood chips during 2011 and 2012. JEA has received bids from local sources to provide sized biomass for potential use for Northside Units 1 and 2.

Plug-in Electric Vehicle Peak Demand

In 2012, JEA developed the PEV demand and energy forecast for the service territory using the 2011 information from the Electric Power Research Institute (EPRI), the Edison Electric Institute (EEi), the U.S. Census Bureau, and the Bureau of Economic and Business Research (BEBR). JEA's baseline forecast of the number of plug-in vehicles in the area was determined from BEBR's forecasted population growth rate, the U.S. Census Bureau's 2010 estimated number of vehicles, and EPRI's forecasted low scenario PEV penetration rate. JEA forecasted the average usable battery capacity per vehicle using the upcoming plug-in vehicle model rollouts from Toyota, Honda, Ford, and General Motors, and grew the capacity by 1 kWh per year. The baseline forecast assumed that charging would initially be uncontrolled at home until the mid-2020s when public infrastructure became feasible and available. When comparing Pike's 2012 PEV forecasted vehicle sales with JEA's 2012 forecast, JEA's baseline projections were 63 percent higher than Pike. Because of this difference, JEA shifted the start of its PEV forecast back 5 years to 2017. Because Pike did not provide forecast data for Duval County, JEA maintained the previously forecasted annual increases.

Staff Evaluation

The JEA forecasts are much more statistically sound. In the past JEA used regression analyses, which would not necessarily account for statistical anomalies. To address the variability, in recent year with the demand, JEA also used historical data, growth rates and established regression analyses for the 13-year progression to establish periods of economic downturn and prerecession periods. JEA forecasted the Net Energy Load to increase at an average of 1.17 percent per year during the last ten-year period. JEA views demand to decline in 2012 and hence over the 13 years the average annual growth rate for total energy is expected to be at 0.73 percent and 0.49 percent for net energy.

Council staff supports JEA and the State of Florida's efforts to continue to develop new programs to: 1) reduce the reliance on coal and oil as energy sources; 2) increase conservation activities to offset the need to construct new power plants; and 3) plan to develop an environmentally sound power supply strategy that may provide reliable electric service at the lowest practical cost.

Recommendation

Staff recommends that the Committee and Council approve this report and authorize its transmittal to the Florida Public Service Commission.

TREASURE COAST REGIONAL PLANNING COUNCIL

INDIAN RIVER – ST. LUCIE – MARTIN – PALM BEACH

June 7, 2013

Mr. Phillip Ellis
Division of Engineering
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, FL 32399-0850

Subject: 2013 Ten Year Power Plant Site Plans

Dear Mr. Ellis:

Treasure Coast Regional Planning Council has reviewed the ten year power plant site plan prepared by Florida Power and Light Company. Council approved the comments in the attached report at a board meeting on May 17, 2013. The report concludes that the FPL Ten Year Power Plant Site Plan, 2013-2022 is inconsistent with **Strategic Regional Policy Plan Goal 9.1**, decreased vulnerability of the region to fuel price increases and supply interruptions. 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.

Please contact me if you have any questions.

Sincerely,

Peter G. Merritt, Ph.D.
Assistant Director

Attachment

cc: Nick Blount, FPL

TREASURE COAST REGIONAL PLANNING COUNCIL

Report on the

Florida Power & Light Company Ten Year Power Plant Site Plan, 2013-2022

May 17, 2013

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 after FPL's demand side management efforts and significant energy efficiency contributions from the federal appliance and lighting efficiency standards 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 2,267 megawatts (MW) of summer capacity to its system from 2013 to 2022. FPL plans to obtain additional electricity through: 1) power purchases from qualifying facilities, utilities, and other entities; 2) upgrades to existing facilities; 3) addition of an existing municipal facility; 4) modernization of existing FPL facilities; and 5) construction of a new generating unit. Major additions of new generating capacity are as follows:

- 2013 – place in service the Cape Canaveral Next Generation Clean Energy Center (1,210 MW) in Brevard County;
- 2014 – place in service the Riviera Beach Next Generation Clean Energy Center (1,212 MW) in the City of Riviera Beach;
- 2016 – place in service the Port Everglades Next Generation Clean Energy Center (1,277 MW) in the City of Hollywood; and
- 2022 – place in service Turkey Point Nuclear Unit 6 (1,100 MW) in Miami-Dade County

Based on the projection of future resource needs, FPL has identified the following seven preferred sites for future power generating facilities:

1. Turkey Point Plant site in Miami-Dade County;
2. Cape Canaveral Plant site in Brevard County;
3. Riviera Beach Plant site in Palm Beach County;
4. Port Everglades Plant site in Broward County;
5. Hendry County site in Hendry County;

6. Northeast Okeechobee County site in Okeechobee County; and
7. Palatka Plant site in Putnam County.

Also, FPL has identified 5 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. Babcock Ranch site in Charlotte County;
2. DeSoto Solar Expansion site in DeSoto County;
3. Manatee Plant site in Manatee County;
4. An unidentified location in Martin County for a photovoltaic (PV) facility; and
5. An unidentified location in Putnam County.

The ten year site plan describes eight factors that are influencing FPL's resource planning work. 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. FPL will begin serving the City of Vero Beach's electrical load beginning January 1, 2014.
4. An updated projection of mandatory efficiency standards for appliances, lighting, and other electrical equipment will result in significant reductions in FPL peak load and net energy for load in 2022.
5. FPL's projected increasing dependence upon demand side management resources to maintain system reliability.
6. The timing of when the Nuclear Regulatory Commission will issue a new schedule for its review of FPL's application for a Combined Operating License for the Turkey Point Units 6 and 7 nuclear units and the potential impact that schedule may have on the overall project schedule.
7. Potential changes in environmental regulations for air emissions could affect FPL's resource plan.
8. The possibility of establishment of a Florida standard for renewable energy or clean energy.

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 one preferred site and one potential site for future power generating facilities in the Treasure Coast Region (Exhibit 2). The preferred site is the Riviera Beach Plant site, which is located in the City of Riviera Beach. The previous generating capacity at this site was made up of two 300 MW oil-fired units, that have been taken out of service and dismantled in 2011. FPL is in the process of modernizing the existing Riviera Beach Plant, which will be renamed the Riviera Beach Next Generation Clean Energy Center. FPL is replacing the existing units with a high-efficiency combined cycle natural gas-fired unit capable of producing 1,212 MW of electricity. Council issued a report supporting

this project in 2009. The new facility has been approved by the FPSC and Florida Department of Environmental Protection, and is expected to start commercial operation in 2014.

Palm Beach County Department of Environmental Resources Management (ERM) has provided comments on the FPL Ten Year Power Plant Site Plan (Exhibit 4). The comments include a discussion of concerns associated with the development and operation of the Riviera Beach Energy Center, which is currently under construction. The concerns are related to thermal pollution of the Lake Worth Lagoon; potential impacts to manatees; potential impacts to organisms from the facility's cooling water intake; stormwater retention; oil spill prevention plans; climate change vulnerability; and sea turtle lighting compliance. Council recommends that FPL meet with representatives from Palm Beach County ERM to discuss how these issues are addressed in the FPL Riviera Beach Energy Center Conditions of Certification and determine if additional actions are necessary to satisfy these concerns.

The only potential site identified in the Treasure Coast Region is in Martin County. The plan indicates FPL is evaluating potential sites in Martin County for a future PV facility. No specific locations have been selected at this time.

New in the 2013, the ten year site plan indicates FPL will begin serving the City Vero Beach's electrical load beginning January 1, 2014. In early 2013, FPL came to an agreement with the City of Vero Beach to purchase the City's electric utility system. FPL is expected to begin providing electric service to more than 34,000 customers formerly served by the City of Vero Beach. As part of FPL's acquisition of Vero Beach's electric utility system, FPL will take ownership of Vero Beach's five existing generating units starting January 2014. The current plan is to immediately retire three of these older generating units and operate the remaining two, which supply approximately 44 MW (Summer) of combined cycle capacity, for a maximum of three years.

The ten year site plan also indicates that FPL is currently evaluating the possibility of serving the electrical loads of several entities, including the City of Lake Worth. However, the load forecast presented in the ten year site plan does not include these potential loads, because these evaluations are still underway.

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 70.6 percent (4.3 percent from coal, 0.2 percent from oil, and 66.1 percent from natural gas) of FPL's electric generation in 2013. The plan predicts fossil fuels will account for 68.7 percent (5.4 percent from coal, 0.1 percent from oil, and 63.2 percent from natural gas) of FPL's electric generation in 2022. During the same period, nuclear sources are predicted to change from 24.0 percent in 2013 to 25.6 percent in 2022. Solar sources are predicted to decline from 0.2 percent in 2013 to 0.1 percent in 2022.

Regarding solar energy, FPL has completed construction of three solar facilities: 1) a 75 MW steam generation solar thermal facility in Martin County (the Martin Next Generation Solar Energy Center); 2) a 25 MW PV electric generation facility in DeSoto County (the DeSoto Next Generation Solar Energy Center); and 3) a 10 MW PV electric generation facility in Brevard

County at NASA's Kennedy Space Center (the Space Coast Next Generation Solar Energy Center). These three projects were completed in response to the 2008 Energy Bill, which was enacted to enable the development of clean, zero greenhouse gas emitting renewable generation in the State of Florida. Specifically, the bill authorized cost recovery for the first 110 MW of eligible renewable projects that had the proper land use, zoning, and transmission rights in place.

In addition to the three solar facilities noted above, the plan indicates that FPL is currently in the process of identifying other potential solar sites in the state. FPL is evaluating existing generation sites along with other sites within FPL's service territory. Council continues to support FPL's existing solar projects and encourages FPL to develop additional projects based on renewable resources.

Conclusion

The FPL ten year site plan is inconsistent with **Strategic Regional Policy Plan Goal 9.1**, decreased vulnerability of the region to fuel price increases and supply interruptions, because the plan predicts continued heavily reliance on only two primary fuel types, natural gas and nuclear fuel. The plan predicts a very slight decrease in the reliance on fossil fuels and a slight increase in the reliance on nuclear energy during the next ten years. This outcome is an incremental step toward consistency with **Strategy 9.1.1**, reduce the Region's reliance on fossil fuels. However, this shift in fuel supply is not sufficient to decreased vulnerability of the region to fuel price increases and supply interruptions. Council recommends that FPL adopt a more balanced portfolio of fuels that includes a significant component of renewable energy sources. Council remains concerned that the ten year site plan does not predict an increase in the use of renewable energy during the next decade. 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 recommends that FPL consider new strategies to expand reliance on renewable sources. FPL should consider expanding its solar rebate programs for customers who install PV and solar water heating systems on their homes and businesses. This program is part of a five-year pilot program authorized by the FPSC to promote clean solar power and reduce energy consumption. The program should be expanded because demand far exceeds the availability of funds. Also, the application period should be coordinated with the Solar and Energy Loan Fund (SELF) so that participants in this program would have the option of receiving a rebate. SELF is a low interest rate loan program that provides financing for clean energy solutions. The current schedule for rebate applications makes it difficult for SELF participants to take part in the FPL rebate program.

FPL should also consider developing a program 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 the 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. The future development of ocean current

technology, which is currently under investigation by the Florida Atlantic University Center for Ocean Energy Technology, may be another opportunity to expand the use of renewable energy.

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

Table III.B.1: Projected Capacity Changes for FPL

Projected Capacity Changes for FPL [1]			
		Net Capacity Changes (MW)	
Year	Projected Capacity Changes	Winter [2]	Summer [3]
2013	Changes to Existing Purchases [4]	(545)	(425)
	Port Everglades Units 3 & 4 retired for Modernization	(765)	(761)
	Turkey Point Unit 2 operation changed to synchronous condenser	(394)	(392)
	Sanford Unit 5 CT Upgrade	—	9
	Turkey Point Unit 4 Uprate - Completed	—	115
	Turkey Point Unit 4 Uprate - Outage [5]	(717)	—
	Sanford Unit 4 CT Upgrade	—	16
	Manatee Unit 2	(3)	—
	Scherer Unit 4	(28)	—
	Cape Canaveral Next Generation Clean Energy Center [6]	—	1,210
	Manatee Unit 1 ESP - Outage [7]	(822)	—
	Martin Unit 1 ESP - Outage [7]	—	(826)
2014	Sanford Unit 5 CT Upgrade	19	10
	Cape Canaveral Next Generation Clean Energy Center [6]	1,355	—
	Changes to Existing Purchases [4]	22	37
	Manatee Unit 1 ESP - Outage [7]	822	—
	Sanford Unit 4 CT Upgrade	16	—
	Vero Beach Combined Cycle [8]	46	44
	Martin Unit 1 ESP - Outage [7]	(832)	826
	Martin Unit 2 ESP - Outage [7]	—	(826)
	Manatee Unit 3 CT Upgrade	—	19
	Turkey Point Unit 5 CT Upgrade	—	33
	Turkey Point Unit 4 Uprate - Completed [5]	115	—
	Riviera Beach Next Generation Clean Energy Center [6]	—	1,212
2015	Manatee Unit 3 CT Upgrade	39	20
	Martin Unit 1 ESP - Outage [7]	832	—
	Martin Unit 2 ESP - Outage [7]	—	826
	Turkey Point Unit 5 CT Upgrade	33	—
	Changes to Existing Purchases [4]	70	70
	Ft. Myers Unit 2 CT Upgrade	—	51
	Riviera Beach Next Generation Clean Energy Center [6]	1,344	—
2016	Changes to Existing Purchases [4]	(858)	(928)
	Ft. Myers Unit 2 CT Upgrade	51	—
	Port Everglades Next Generation Clean Energy Center [6]	—	1,277
2017	Turkey Point Unit 1 operation changed to synchronous condenser	(398)	(396)
	Changes to Existing Purchases [4]	(37)	(37)
	Vero Beach Combined Cycle [8]	(46)	(44)
	Port Everglades Next Generation Clean Energy Center [6]	1,429	—
2018	Changes to Existing Purchases [4]	(388)	(381)
2019	—	—	—
2020	—	—	—
2021	Changes to Existing Purchases [4]	180	180
2022	Turkey Point Nuclear Unit 6 [6]	—	1,100

(1) Additional information about these resulting reserve margins and capacity changes are found on Schedules 7 & 8 respectively.
(2) Winter values are forecasted values for January of the year shown.
(3) Summer values are forecasted values for August of the year shown.
(4) These are firm capacity and energy contracts with QF, utilities, and other entities. See Table I.B.1 and Table I.B.2 for more details.
(5) Outages for uprate work.
(6) All new unit additions are scheduled to be in-service in June of the year shown. All additions assumed to start in June are included in the Summer reserve margin calculation starting in that year and in the Winter reserve margin calculation starting with the next year.
(7) Outages for ESP work.
(8) This unit will be added as part of the agreement that FPL will serve Vero Beach's electric load starting January, 2014. This unit is expected to be retired within 3 years.

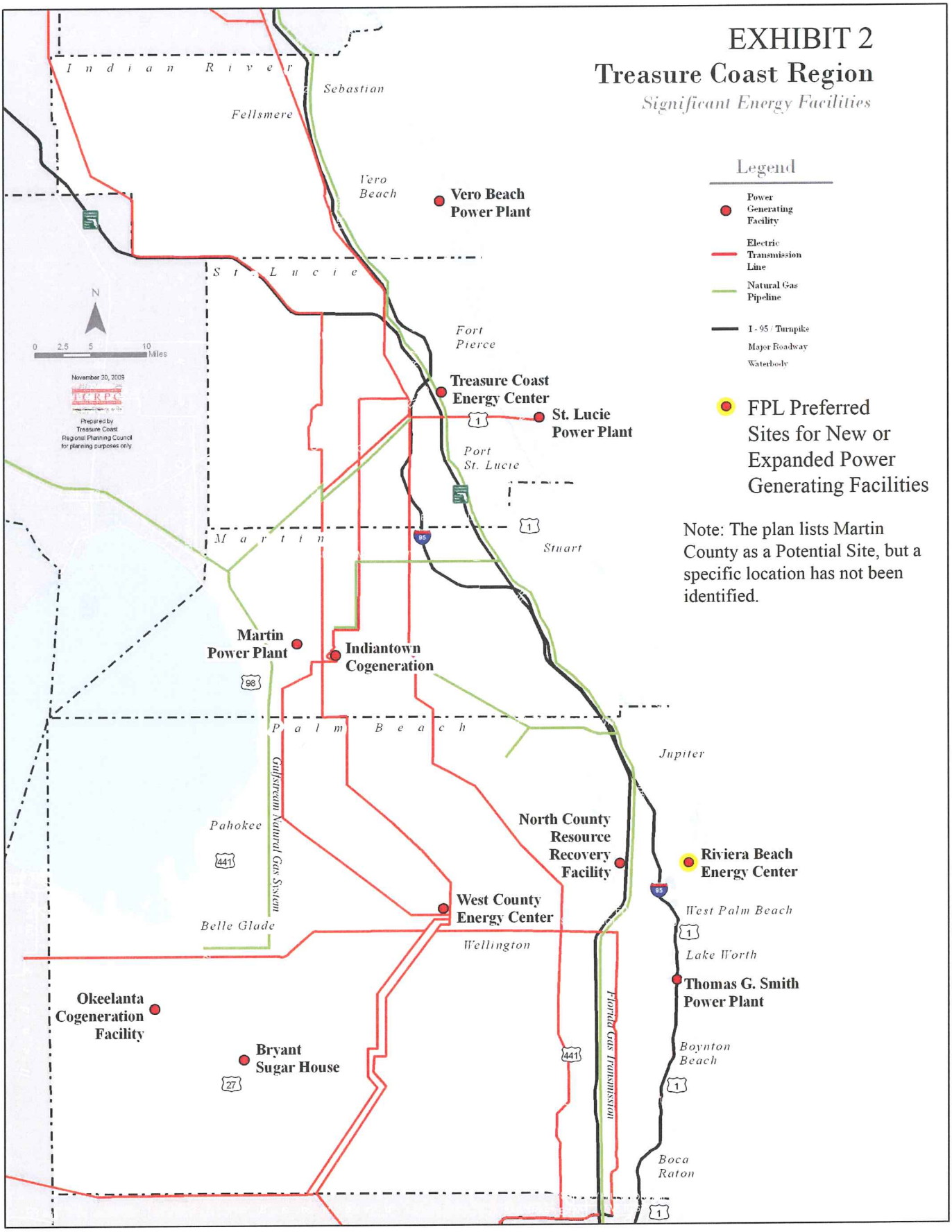


EXHIBIT 2
Treasure Coast Region
Significant Energy Facilities
Legend
Power Generating Facility
Electric Transmission Line
Natural Gas Pipeline
I - 95 / Turnpike
Major Roadway
Waterbody
FPL Preferred Sites for New or Expanded Power Generating Facilities
Note: The plan lists Martin County as a Potential Site, but a specific location has not been identified.
Indian River
Sebastian
Fellsmere
Vero Beach
Vero Beach Power Plant
St. Lucie
Fort Pierce
Treasure Coast Energy Center
St. Lucie Power Plant
Port St. Lucie
Martin
Stuart
Martin Power Plant
Indiantown Cogeneration
Palm Beach
Jupiter
Pahokee
Belle Glade
Gulfstream Natural Gas System
North County Resource Recovery Facility
Riviera Beach Energy Center
West County Energy Center
Wellington
West Palm Beach
Lake Worth
Thomas G. Smith Power Plant
Okeelanta Cogeneration Facility
Bryant Sugar House
Florida Gas Transmission
Boynton Beach
Boca Raton
N
0 2.5 5 10 Miles
November 20, 2009
TCRPC
Prepared by Treasure Coast Regional Planning Council for planning purposes only

EXHIBIT 3

Schedule 6.2
Energy Sources % by Fuel Type

Energy Source	Units	Actual [1] 2011	Actual [1] 2012	Forecasted 2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
(1) Annual Energy Interchange [2]	%	5.3	4.7	1.9	2.3	2.5	1.0	0.1	0.0	0.0	0.0	0.0	0.0
(2) Nuclear	%	19.1	15.3	24.0	23.4	23.1	23.2	22.7	22.2	22.5	21.9	21.6	25.6
(3) Coal	%	5.0	4.3	4.3	4.4	4.9	4.4	4.9	4.8	5.2	5.3	5.5	5.4
(4) Residual (FO6) -Total	%	0.6	0.3	0.2	0.2	0.3	0.3	0.1	0.2	0.1	0.2	0.2	0.1
(5) Steam	%	0.6	0.3	0.2	0.2	0.3	0.3	0.1	0.2	0.1	0.2	0.2	0.1
(6) Distillate (FO2) -Total	%	0.1	0.0	0.0	0.0	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0
(7) Steam	%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(8) CC	%	0.1	0.0	0.0	0.0	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0
(9) CT	%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(10) Natural Gas -Total	%	66.1	72.6	66.1	66.3	65.4	66.9	68.0	68.9	66.9	67.0	67.1	63.2
(11) Steam	%	4.8	5.0	0.2	0.1	0.2	0.4	0.3	0.4	0.3	0.4	0.4	0.3
(12) CC	%	60.8	67.3	65.8	66.1	65.1	66.5	67.6	68.4	66.5	66.5	66.6	62.8
(13) CT	%	0.6	0.3	0.1	0.1	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1
(14) Solar [3]	%	0.1	0.1	0.2	0.2	0.1	0.2	0.1	0.1	0.1	0.1	0.1	0.1
(15) PV	%	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
(16) Solar Thermal [4]	%	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
(17) Other [5]	%	3.6	2.6	3.3	3.3	3.7	4.0	4.0	3.7	5.1	5.4	5.5	5.6
		100	100	100	100	100	100	100	100	100	100	100	100

1/ Source: A Schedules and Actual Data for Next Generation Solar Centers Report
2/ The projected figures are based on estimated energy purchases from SJRPP, the Southern Companies (UPS contract), and other utilities.
3/ Represents output from FPL's PV and solar thermal facilities.
4/ For 2011, the Martin 8 Solar Thermal GWh output is rolled into row (12) for reporting purposes. In 2012, the GWh output is presented in row (16). The projected GWh contributions for 2013-2022 are also provided on row (16).
5/ Represents a forecast of energy expected to be purchased from Qualifying Facilities, Independent Power Producers, net of Economy and other Power Sales.

EXHIBIT 4

Department of Environmental Resources Management
2300 North Jog Road, 4th Floor
West Palm Beach, FL 33411-2743
(561) 233-2400
FAX: (561) 233-2414
www.pbcgov.org/erm

May 2, 2013

Ms. Liz Gulick, Administrative Supervisor
Treasure Coast Regional Planning Council
421 SW Camden Avenue
Stuart, Florida 34994

Dear Ms. Gulick:

SUBJECT: **PALM BEACH COUNTY COMMENTS FOR THE FPL 10 YEAR POWER PLANT SITE PLAN**

Palm Beach County Department of Environmental Resources Management (ERM) staff has reviewed the information contained in the site plan and have the following concerns:

- The Florida Power & Light (FPL) Power Plant will utilize Lake Worth Lagoon water as a cooling source and discharge it in the Lagoon. Thermal pollution remains a concern since it can potentially affect dissolved oxygen and cause increased stress to aquatic organisms and seagrass. Confirmation is requested that increased thermal stress is not expected from the new plant.

- One of the impacts of the thermal pollution is that the discharge has developed into a warm water refuge for up to 800 manatees and thus any disruption to the operation schedule could have the potential for negative impacts to manatees. Changes in manatee distribution have been evident in recent years due to the intermittent operation of the temporary heating system. We expect that the operation schedule of the new plant will be similar to the old plant and provide a more continuous and dependable warm water source which should reduce potential manatee impacts. It is understood that there is a working group evaluating plans for alternative warm water sources to reduce the dependence of manatees on this artificial source.

- The plant is projected to use 600 million gallons of lagoon water daily. The biological impact due to impingement and entrainment of fish and planktonic invertebrates drawn into a facility's cooling water intake is expected to be significant and may be the primary impact to the Lake Worth Lagoon (LWL). This is particularly critical given the biologically unique location of LWL and its fish and invertebrate diversity which is a function of its proximity to the Gulfstream Palm Beach County would like to be provided with an assessment of those impacts and a summary of steps to minimize any adverse environmental impacts.

- Increasing stormwater retention from stormwater runoff above the minimum requirements is recommended due to the critical location of the plant to sensitive resources and to reduce the chance of an inadvertent release of pollutants.

- The site plan does not appear to address the potential discharge from the oil fuel pipeline when a fuel delivery is made. No details of the length of the pipeline or Spill Prevention plans have been provided in this report in the case of an accidental release.

- Sea Level Rise could have at least two potential impacts on the proposed Plant: inundation as result of rising waters that could be enhanced when combined with storm surges; and the possibility of salt water intrusion into the Surficial Aquifer, which will be used as one of the water sources for the plant's operations. ERM suggests that climate change vulnerability be incorporated into the plants operational protocols.

- The plan should demonstrate compliance with Palm Beach County's Sea Turtle Lighting criteria by including shields for light fixtures to decrease skyglow which is known to result in hatchling disorientation in this area.

Should you have further inquiries regarding this issue please contact me at (561) 233-2400, or Bob Kraus at (561) 233-2476.

Sincerely,

Robert Robbins, Department Director
Environmental Resources Management

rr:pd:rk
cc: Robert Banks, Assistant County Attorney
Palm Beach County Attorney's Office
Rebecca Caldwell, Executive Director
Palm Beach County Planning, Zoning & Building
Lorenzo Aghemo, Planning Director
Palm Beach County Planning, Zoning & Building
Isaac Hoyos, Principal Planner
Palm Beach County Planning, Zoning & Building
Paul Davis, Division Director, Environmental Enhancement & Restoration
Palm Beach County Department of Environmental Resources Management

APPENDIX A

Water Management Districts

- South Florida Water Management District
- Southwest Florida Water Management District
- St. John's River Water Management District
- Suwannee River Water Management District

SOUTH FLORIDA WATER MANAGEMENT DISTRICT

June 28, 2013

RECEIVED
JUL 02 2013
BY:

Mr. Phillip Ellis
Engineering Specialist III
Division of Engineering
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, Florida 32399-0850

Dear Mr. Ellis:

Subject: 2013 Ten-Year Site Plans for Florida Electric Utilities

Thank you for your May 21, 2013 letter requesting that the South Florida Water Management District (District) review the 2013 Ten-Year Site Plans for the Florida Power & Light Company (FPL), Progress/Duke Energy Florida (DEF), and Tampa Electric Company (TECO). The District has completed its review of the site plans.

The ten-year site plans provided by DEF and TECO do not include existing or proposed facilities within the boundaries of the District. The District forwards no comments regarding these proposed sites.

The District finds the ten-year site plan provided by FPL suitable as a planning document. The District offers the following comments to assist electric utilities with ongoing planning.

In planning for siting future facilities, utilities should recognize that water availability is limited in specified areas by the District's Restricted Allocation Area rule. The criteria associated with the Restricted Allocation Area Rule can be found in Section 3.2.1 of the Basis of Review for Water Use Permit Applications within the South Florida Water Management District (October 23, 2012).

For assistance or additional information, please contact John Morgan, Lead Policy Analyst, at (561) 682-2288 or jmorganj@sfwmd.gov.

Sincerely,

Sharon M. Trost, P.G., AICP
Director, Regulation Division
South Florida Water Management District

SMT/jm

Southwest Florida Water Management District
2379 Broad Street, Brooksville, Florida 34604-6899
(352) 796-7211 or 1-800-423-1476 (FL only)
On the World Wide Web at WaterMatters.org

An Equal Opportunity Employer

Bartow Service Office
170 Century Boulevard
Bartow, Florida 33830-7700
(863) 534-1448 or
1-800-492-7862 (FL only)

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
Tampa, Florida 33637-6759
(813) 985-7481 or
1-800-836-0797 (FL only)

June 11, 2013

Mr. Phillip Ellis, Engineering Specialist III
Division of Engineering
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, FL 32399-0850

Subject: Electric Utility 2013 Ten-Year Site Plans

Dear Mr. Ellis:

In response to your request, the Southwest Florida Water Management District (District) has completed its review of the 2013 Ten-Year Site Plans (Site Plan) for Progress/Duke Energy Florida (DEF) and Tampa Electric Company (TECO). The District's review is being conducted pursuant to Section 186.801(2)(e), Florida Statutes, which requires that the Public Service Commission 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."

Both DEF and TECO indicate in their Site Plans that new generating facilities are proposed within the ten-year planning horizon. The Site Plan for DEF indicates that two new combined cycle units are proposed in 2018 and 2020 at undesignated sites. The Site Plan for TECO indicates that conversion of the Polk Power Station's simple cycle combustion turbines (Units 2-5) to a natural gas combined cycle unit is currently undergoing site certification review and is proposed for 2017. The Site Plan for TECO also indicates that a new combustion turbine is proposed in 2020 at an undesignated site.

With the exception of the TECO Polk Power Station Units 2-5 project, which is currently undergoing site certification review, no information was provided for the other TECO project and the two DEF projects concerning identification of the proposed project sites, water sources, and water demands. Without this information, the District's ability to comment on the "suitability" of the Site Plans is extremely limited.

Please note that, pursuant to Section II.A.1.f of the current Operating Agreement between the Florida Department of Environmental Protection (DEP) and the District concerning the division of responsibility for management and storage of surface waters regulation and wetland resource regulation under Chapter 373, Part IV, Florida Statutes, the DEP is responsible for conducting the Environmental Resource Permit-related review and for taking final agency action for power plants, electrical distribution and transmission lines, and other facilities related to the production, transmission, and distribution of electricity.

Based on the information provided in the Site Plans, the District offers the following technical assistance comments for your consideration:

1) During the site certification or permitting process, consideration must be given to the lowest quality water available which is acceptable for the proposed use. If a lower quality of 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.

2) For new generating facilities proposed in the southern and much of the central portions of the District, there are additional water use restrictions. 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 lake levels and reduced stream flows, which have been caused by excessive ground water withdrawals. Regional recovery strategies are being implemented to address the adverse water resource impacts. Consequently, the District has heightened concerns regarding potential impacts due to future groundwater demands and availability within these areas.

3) 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.

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,

James J. Golden, AICP
Senior Planner

JG

St. Johns River
Water Management District
Hans G. Tanzler III, Executive Director • David W. Fisk, Assistant Executive Director

4049 Reid Street • P.O. Box 1429 • Palatka, FL 32178-1429 • (386) 329-4500
On the Internet at floridaswater.com.

July 17, 2013

Mr. Philip Ellis
Division of Engineering
Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, Florida 32399-0850

Re: Review of the 2013 Ten-Year Site Plans for Florida's Electric Utilities

Dear Mr. Ellis:

St. Johns River Water Management District (District) staff have reviewed the Ten-Year Site Plans (TYSPs) for Florida Power & Light Company (FPL), Progress / Duke Energy Florida (DEF), Gainesville Regional Utilities (GRU) and JEA relative to suitability as planning documents, as requested in your letter dated May 21, 2013. District staff comments are below.

1. Pursuant to subsection II, A.1.f., of the 2007 operating agreement concerning regulation between the District and the Florida Department of Environmental Protection (DEP), DEP shall review and take final action on all applications for permits for power plants and electrical distribution and transmission lines and other facilities related to the production, transmission, and distribution of electricity.

2. As planning documents, TYSPs do not contain detailed information relative to projected water demand. However, when locating or expanding a site for a power facility, FPL, DEF, GRU, and JEA should consider the availability of water to meet the projected demands of the facility and potential impacts due to facility water use, including the cumulative impacts. In general, the District requires that all consumptive use permit (CUP) applications for new uses and requested increases in CUP allocations demonstrate use of the lowest-quality water source; justify the need for the requested allocation; demonstrate efficient use; and not impact springs, wetlands, water bodies, water quality, or existing legal uses.

If you have any questions, please contact District Intergovernmental Planner Steve Fitzgibbons at (386) 312-2369 or *sfitzgib@sjrwmd.com.*

Sincerely,

Jeff Cole
Chief of Staff

SUWANNEE
RIVER
WATER
MANAGEMENT
DISTRICT

August 1, 2013

Phillip Ellis
Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, FL 32399

Subject: Review of the 2013 Ten-Year Plans for Florida's Electric Utilities

Dear Mr. Ellis:

The following are comments as requested in your May 21st letter.

Progress/Duke Energy Florida (DEF):
The Suwannee River Generating Plant (SRGP) is located directly on the banks of the Suwannee River near Ellaville. The Suwannee River provides cooling water for the SRGP. The SRGP is not located within a Water Resource Caution Area; therefore current demand is not anticipated to exceed supply in the next twenty years.

Gainesville Regional Utilities (GRU):
The Deerhaven Generating Station (DGS) is located on the border between the Upper Santa Fe Water Resource Caution Area (WRCA) and the Lower Santa Fe WRCA. In both of these caution areas, the projected demands will exceed the available supply within the next twenty years.

The District is currently establishing minimum flows and levels (MFLs) for the Lower Santa Fe River, Ichetucknee River and associated priority springs. In conjunction with MFL establishment, the District is developing strategies to prevent the Ichetucknee River and associated priority springs flows and levels from falling below established minimums. For the Lower Santa Fe River and priority springs, the District is developing strategies to recover flows and levels. The prevention and recovery strategies will employ water conservation, alternative water supplies, water resource development projects, and regulation of consumptive uses of water. Facility plans should be coordinated with District staff during the development of these strategies and the water supply planning process.

Seminole Electric Cooperative (SEC):
Seminole Electric Cooperative currently does not have an active plant within the District. There is a proposed generating station in Gilchrist County to be located near Bell. This generating station is located in a basin which contributes to the Lower Santa Fe River. The comments in the previous paragraph are applicable here.

Sincerely,

Ann B. Shortelle, Ph.D.
Executive Director

TS/lm

9225 CR 49 • LIVE OAK, FLORIDA 32060 • TELEPHONE 386/362-1001 • 800/226-1066 (FL) • FAX 386/362-1056
mysuwanneeriver.com

APPENDIX A

Local Governments

- Citrus County

Board of County Commissioners

DEPARTMENT OF PLANNING AND DEVELOPMENT

3600 W. Sovereign Path, Lecanto, FL 34461-8070
Toll Free (352) 489-2120 TTY (352) 527-5312
Web Address: www.bocc.citrus.fl.us

In reply, refer to:
DS-13-022

July 23, 2013

Phillip Ellis
Engineer Specialist III
State of Florida Public Service Commission
Capital Circle Office Center
2540 Shumard Oak Boulevard
Tallahassee, FL 32399-0850

RE: Review of the 2013 Ten-Year Site Plans for Progress/Duke Energy Florida (DEF)

Dear Mr. Ellis:

This Department has reviewed the Progress/Duke Energy Florida Ten-Year Site Plan dated April 2013 and does not find any conflicts with growth management policies as specified in the Citrus County Comprehensive Plan.

It is noted that this document focuses on environmental and land use information for sites within the Progress /Duke Energy Florida system that are primarily located outside of Citrus County. The Plan notes the retirement of the Crystal River Nuclear Units 1, 2, and 3, and planned installation of combined cycle facilities in 2018 and 2020 at sites that have not yet been identified.

Thank you for the opportunity to review the Plan. If you require additional feedback, please do not hesitate to contact this office.

Sincerely,

Vincent A. Cautero, AICP
Director
Department of Planning and Development

VAC/JBC/rls

CC: Ken Frink, P.E., Assistant County Administrator
Jenette Collins, AICP, Director, Land Development Division
Jim Faulkner, Director, Geographic Resources and Community Planning Division

(F)

STATE OF FLORIDA

DIVISION OF ENGINEERING
TOM BALLINGER
DIRECTOR
(850) 413-6910

Public Service Commission

May 21, 2013

Fwd: TO C.P, K.F
VINCE C. SHOULD LOOK AT THIS
BLAD
5.24.13

Mr. Brad Thorpe
County Administrator
Citrus County
110 N. Apopka Drive
Inverness, FL 34450

Dear Mr. Thorpe:

Re: Review of the 2013 Ten-Year Site Plans for Florida's Electric Utilities

Pursuant to Section 186.801, Florida Statutes, the Florida Public Service Commission (Commission) is responsible for reviewing and classifying each electric utility's Ten-Year Site Plan as "suitable" or "unsuitable." As part of the annual review in accordance with Rule 25-22.071, Florida Administrative Code, the Commission must provide a copy of the relevant Ten-Year Site Plans and solicit the views of appropriate state, regional, and local agencies. To this end, the Commission has made available on its website electronic copies of the 2013 Ten-Year Site Plans for all the Florida electric utilities at the following link:

http://www.psc.state.fl.us/utilities/electricgas/10yrsiteplans.aspx

Below is a list of those electric utilities that have identified preferred or potential plant sites in your jurisdiction. Please review these Ten-Year Site Plans and provide comments, along with a brief summary if possible, on their suitability as planning documents. Please note that these plans are not designed to give information about proposed facilities in such detail as would be required for a development permit or other formal process.

Relevant 2013 Ten-Year Site Plans

- Progress / Duke Energy Florida (DEF)

Please forward all comments by August 1, 2013, including an electronic copy to my e-mail address below. If you have any questions, require additional time to file comments, or would like to receive a hardcopy of the Ten-Year Site Plans, please feel free to contact me at (850)-413-6626 (pellis@psc.state.fl.us). Thank you for your assistance.

Regards,

Phillip Ellis
Engineering Specialist III

POE

cc: Office of Commission Clerk (Cole)
Division of Engineering (Ballinger, Vickery)
Office of the General Counsel (Murphy)

APPENDIX A

Other Organizations

- Sierra Club and Earthjustice

Mr. Phillip O. Ellis
Strategic Analysis & Government Affairs
Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, FL 32399-0850
pellis@psc.state.fl.us

CC: Traci Matthews
tmatthew@psc.state.fl.us

Re**:** Comments on 2013 Ten-Year Plan Submittals

Dear Mr. Ellis and Ms Matthews:

Thank you for accepting these comments on behalf of the Sierra Club and its nearly 27,000 Florida members and on behalf of Earthjustice. We appreciated the opportunity to participate in the Public Service Commission (PSC)'s Ten-Year Plan review process in 2012, and are happy to continue our participation this year.

In last year's comments,[1] we asked that the PSC consider the implications of the retirement of Duke (then Progress) Energy's Crystal River Units 1 & 2, and of Gulf Power's Lansing Smith Units 1 & 2. We advised the PSC that the units had significant environmental compliance obligations which rendered them noneconomic to run in the near-term, but that neither company had included full analysis of that possibility in its submittal.

We appreciate that the PSC addressed these retirement issues in its review of the 2012 plans. *See, e.g.*, PSC, *Review of the 2012 Ten-Year Site Plans* ("*2012 Review*") at 3. We respectfully submit that that analysis should continue in further depth this year because both utilities have now confirmed our retirement predictions from last year. Duke has committed to retiring Crystal River 1 & 2 for economic reasons and Gulf, though it has not made a final decision, has deferred further environmental compliance work on Lansing Smith and has requested PSC approval for transmission upgrades which would allow for Lansing Smith 1 & 2 to shut down.

In its review, the PSC assumed that the capacity of these retiring units would be replaced by natural gas, which would increase natural gas's share in Florida's electric generation to 62.9% by 2022 (up from 56.7% without the retirements, and from 57.7% in 2011). *Id.* The PSC states that it views "the growing lack of fuel diversity" within Florida as a "major strategic concern." *Id.* at 39. Although we certainly welcome the retirements of these dangerous coal plants, we share this fuel diversity concern: Undue dependence on natural gas leaves the state overly vulnerable to fuel price volatility, even as potential LNG exports and other shifts in the gas market seem likely to increase gas prices in the medium term. For this reason, we strongly suggest that the PSC consider planning scenarios which employ other, less risky, resources to make up some or all of the share of generation now served by the retiring plants.

[1] Attached as Exhibits 1 & 2, for your reference.

In particular, we believe that demand-side management measures, including energy efficiency, other demand response programs, and demand-side renewable energy, can make up a significant portion of any resource gap left by the likely retirements. Increased supply side renewable energy can also increase the diversity of the state's resource mix. Because the PSC will be considering new goals for both Duke and Gulf under the Florida Energy Efficiency and Conservation Act (FEECA) this year, this is a particularly good time to develop the data needed for sensible planning.

I. Coal Retirements

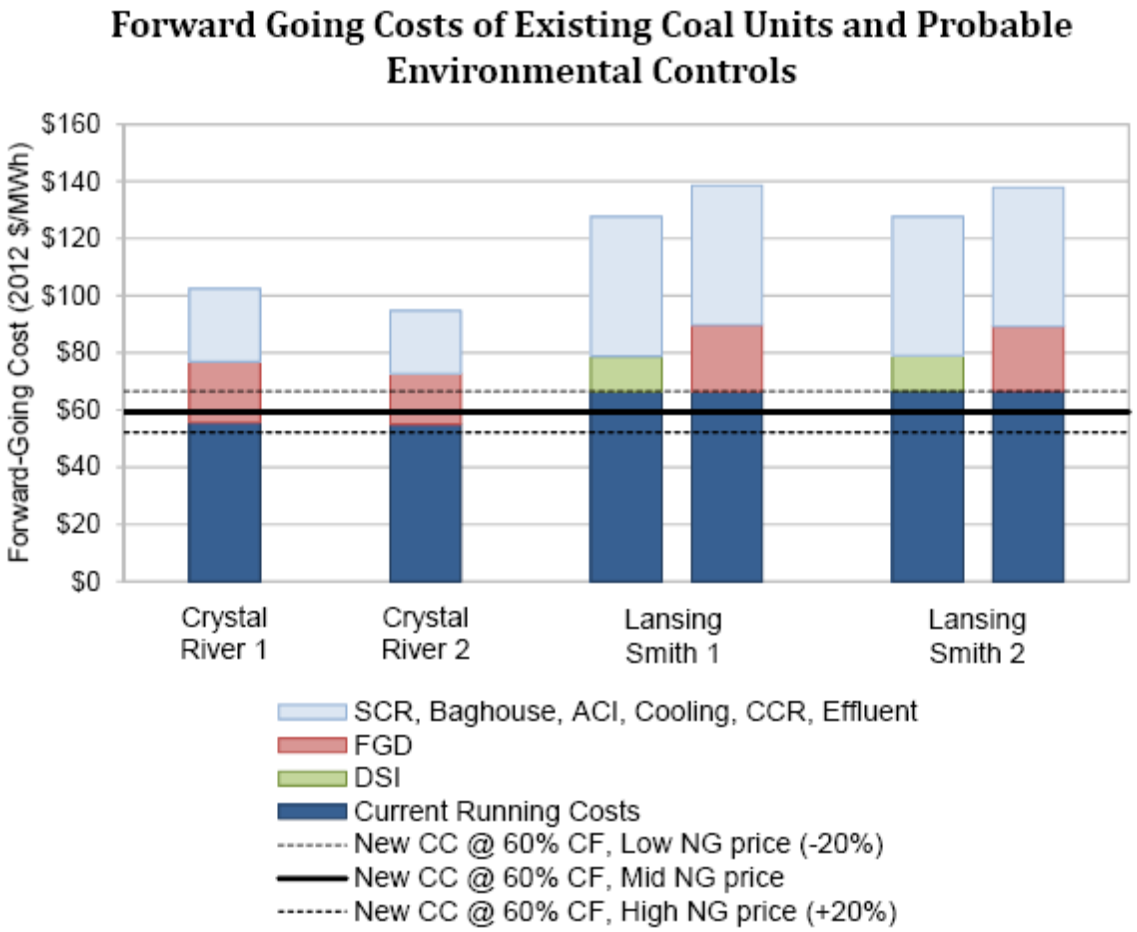
Both Duke and Gulf have confirmed that retirement is likely in the cards for their economically vulnerable plants, though Duke has gone further and confirmed that Crystal River 1 & 2 will certainly retire. Duke appears to be planning to address these retirements largely through adding new generating capacity. Gulf intends to rely on power imports in the near term.

Duke/Progress

Duke has confirmed "expected retirement of Crystal River 1 & 2 in 2016." Duke TYSP at 3-2. As Duke explains in testimony filed in the Environmental Cost Recovery Docket, the lifecycle projected system cost for retiring units 1 & 2 is far lower than the cost of retrofitting the units to comply with environmental compliance obligations: The difference between the retirement and retrofit scenarios is $ 1.32 billion in Duke's base case analysis; retrofit is unfavorable only in the extremely unlikely case of very high gas prices and no CO_2 regulation. Direct Testimony of Benjamin M. H. Borsch on Behalf of Progress Energy Florida (Apr. 1, 2013) at 4, Docket No. 130007-EI; *see also* Progress Energy Florida, *Review of Integrated Clean Air Compliance Plan* (Apr. 1, 2013) ("*Duke Compliance Plan*") at 25-26.

To be sure, Duke has held out the option of making short-term fuel mix adjustments which might allow the units to continue operating, perhaps as long as 2020. *Duke Compliance Plan* at 21. Continued operation would plainly be economically imprudent. As we demonstrated in our comments and workshop presentation on last year's plan, and as the figure below shows, the Crystal River units already verge on noneconomic when compared even against the substantial expense of constructing a new combined cycle natural gas plant to replace their capacity, much less against more sensible options, including demand side programs.[2]

[2] This figure is drawn from our 2012 workshop presentation and is based on work by Synapse Energy Economics, using public cost estimates from the Energy Information Administration's cost reporting forms and the EPA's Integrated Planning Model, developed by Sargent & Lundy.



Because Crystal River 1 & 2 are uneconomic by almost any measure (as Duke acknowledges), the pertinent question is how best to replace any portion of their 965 MW in nameplate capacity which will be required going forward. (In practice, this lost capacity is smaller: both units have been relatively little used in recent years.) Lost capacity from the 860 MW Crystal River 3, the retired nuclear unit at the site, will also play a substantial role in system planning, of course.

Over the period from 2013 to 2022, Duke expects its firm summer peak demand to grow by 1287 MW, TYSP at 3-7, and increase of just shy of 15% over the next decade, or about 1.5% per year. At present, Duke reports that it intends to make up necessary capacity to match this growth through "planned power purchases from 2016 through 2020 and planned installation of combined cycle facilities in 2018 and 2020 at undesignated sites." *Id.* at 3-2. According to Duke, these energy imports are likely to grow an additional 1470 MW above its current ~ 1900 MW of imported capacity, *id.* at Schedule 7.1. The addition of a 1307 MW (winter capacity) combined cycle facility in 2018, and a second 1307 MW facility in 2020 then replaces these imports. *See id.* at 3-7, 3-10 – 3-11. This additional capacity is 764 MW greater than the capacity which Duke is losing, leading to a 21% reserve margin by 2022.

As we discuss below, Duke's strategy of increasing its built generating capacity substantially in response to projected growth, and relying on natural gas generation to do so, is not the prudent one for either the company or for Florida.

Gulf Power

As the figure above indicates, Lansing Smith 1 & 2 are even less economically attractive to operate than the uncontrolled Crystal River coal units. Gulf has not yet committed to retirement publicly, but its filings in this docket and in the Environmental Cost Recovery docket make clear that it is preserving that option.

Specifically, Gulf has requested the PSC approve a $77 million transmission upgrade project, which it explains is necessary to ensure that Lansing Smith is not a must run unit. Gulf Power, *Third Supplemental Petition of Gulf Power Company Regarding its Environmental Compliance Program*, Docket No. 13007-EI (Mar. 29, 2013) at 8. According to Gulf, these upgrades will allow Plant Smith to run at lower levels or to close, and would be "required if these units retire or are controlled as a result of [the mercury and air toxics rule]." *Id.* at 8. Gulf, thus, maintains that it intends to "reserve the decision to install … controls or to retire the two units for a future time when more is known with regard to costs of compliance requirements associated with additional environmental regulations." *Id.*

Because Gulf Power – unlike Duke – has not shared cost information with the public comparing the cost of controlling versus retiring the plant, *see* Gulf Power, Environmental Compliance Program Update, Docket No. 13007-EI (Mar, 29, 2013) at 22-27, it is clear that it anticipates considerable additional compliance obligations at Plant Smith, including additional air, water, and waste rules. *Id.* at 22. Although Gulf has not provided economic analysis of a retirement option, it is clear that operating costs from the mercury rule alone would "greatly increase the variable operating cost of Smith Units 1 and 2," *id.* at 23, enough so that spending $77 million on transmission to reduce the operating need for the plant is more economic than continuing to run it, *id.* at 26.

We certainly agree that it is better to run Plant Smith less. The truth, however, is that Plant Smith is not economic to run *at all* under current conditions. It is certainly not economic to run going forward as environmental compliance costs increase. The appropriate course for Gulf Power is to retire the facility, rather than simply building transmission which will allow it to operate the costly plant somewhat less. Its transmission project, apparently, will enable that retirement, which remains an option. We urge the PSC to continue to analyze retirement possibilities.

In this regard, Gulf's Ten Year Site Plan submission does not clearly discuss all the implications of Plant Smith. It acknowledges, again, that "potential incremental capital expenditures for compliance may be substantial," Gulf TYSP at 3, but does not yet appear to provide a straightforward retirement analysis. Gulf anticipates 575 MW in summer peak demand growth by 2022 (about 20% growth over that period, or, according to Gulf, a 1.9% annual increase over the next decade). *See* Gulf TYSP at Schedule 3.1.

Gulf's plan indicates that capacity additions are not necessary to manage this projected growth. Gulf reports that a power purchase agreement (PPA) which it has signed with Shell Energy for use of 885 MW of capacity from an existing gas combined cycle plant will meet its needs through 2023, after which it will construct additional in-system capacity. *Id.* at 2-3. For this reason, the PSC's projection last year that Lansing Smith's retirement will lead to gas generation increases in Florida appears to be incorrect in the near term. As with Crystal River's retirement, however, we believe that demand-side

options and other non-gas resources should be emphasized to meet any capacity needs that eventually arise.

II. Implications for the Ten-Year Plan and FEECA Goal-Setting Processes

Because the PSC will shortly move fully into the FEECA goal-setting process for the next five years, this is a particularly appropriate time to consider alternate futures for the Duke and Gulf power networks, with an emphasis on resources which the Legislature designed FEECA to encourage. The cost of adding new fossil capacity will almost always be higher than the cost of demand-side measures. The savings possible through an efficiency-focused strategy, coupled with efficiency's potential to help Florida avoid the undue dependence on natural gas which the PSC is seeking to avoid, argue strongly for a careful analysis of these questions in this year's Ten-Year Site Plan Review.

The Legislature has determined that it is "critical to utilize the most efficient and cost-effective demand-side renewable energy systems and conservation systems in order to protect the health, prosperity, and general welfare of the state and its citizens." Section 366.81, F.S. A study commissioned by the Legislature this past year confirmed these findings, concluding that "FEECA appears to provide a positive net benefit to ratepayers." Galligan *et al.*, *Evaluation of Florida's Energy Efficiency and Conservation Act* (Dec. 7, 2012) ("*FEECA Study*") at 9.

Despite these benefits, the PSC has, in the past, opted to suspend further program expansion for Duke and FPL, on cost grounds. *See*, e.g.*, Re: Progress Energy Florida, Inc.*, Docket No. 1000160-EG, 2001 WL 3659327 (Aug. 6, 2011). The PSC should revisit this position during this year's goal-setting process in view of the positive findings of the legislative study, and the pressing need to address the retirements of vulnerable coal units in ways that best protect the ratepayers from further risk from fossil fuel price shifts and regulatory uncertainty. Ratepayers will face costs associated with new capacity and loss of fuel supply diversity which are far greater than those imposed by demand-side programs --- programs which the legislative study have determined have net *benefits*.

In particular, the PSC should view with skepticism Duke's proposal to construct 2614 MW of natural gas generation in just the next few years in order to cope with a 1.5% annual average growth rate in its predicted demand. Initially, Duke has a history of significant positive errors in its forecasts. As the PSC explained in its 2012 Ten Year Site Plan Review, Duke overestimated net energy for load forecasts by 11.36% on average between 2007 and 2011, and by 6.17% between 2006 and 2010. *2012 Review at 19*. Certainly the recession contributed to some of this overage, but the size of the error should give the PSC pause.

More importantly, however, the 1.6% demand growth rate which Duke forecasts, even if accurate, is within the range of load growth rates which demand-side management can address. According to the legislative FEECA study, many states require annual reductions far greater. *See FEECA Study* at 177-180. States requiring savings of at least 1% a year, according to that study, include Arizona, Indiana, Maine, Maryland, Michigan, Minnesota, New York, Ohio, and Texas, with many other states not far behind (still other states, including California, are listed as having very large reduction goals, but a percentage reduction is not specified). *See id.* Such reduction rates would entirely offset Duke's projected load growth, obviating the need for much, if not all, of its projected capacity needs in light of the Crystal River retirements.

Duke plainly has the potential to greatly expand its programs. It reports that only 25% (405,000 customers out of 1.6 million) take part in its demand response program, for instance. Duke TYSP at 1-1. This low participation is likely one reason that Duke is well below its FEECA goals for summer MW and annual GWh reductions – missing the annual target by more than 60%. *See* PSC, *Annual Report on Activities Pursuant to [FEECA]* (Feb. 2013) at 19. Duke has told the PSC that it was unable to reach its performance levels because "of the Commission decision to not approve a new DSM plan" for the company. *Id.* at 20. Thus, if the PSC engages with Duke to approve an improved plan, Duke may well be able to increase efficiency programs sufficiently to greatly decrease its capacity needs.

This analysis also applies to Gulf. Although Gulf does not plan new capacity for the next decade, it, too, has potential for further improvements, failing to meet even its modest existing FEECA goal by 12%. *Id.* at 19. If Gulf were performing at the level of nationally leading utilities – saving more than 1.5% of its demand per year – it could likely avoid those projected capacity additions.

Such enhanced performance could help Florida, as a whole, to meet the Legislature's directive in FEECA. At present, Florida ranks in the bottom half of the states with regard to energy efficiency. *See* American Council for an Energy-Efficient Economy, *State Scorecard 2012* (ranking Florida #29).[3] The coal retirements before the PSC provide a strong incentive to do better.

We understand that the PSC will be conducting substantial analysis on this front during its FEECA goal-setting process, *see* Section 366.82, F.S., which requires careful consideration of the "full technical potential" of demand-side programs. We suggest that the PSC conduct that analysis in tandem with its Ten-Year Site Plan review, valuing demand-side programs as a resource which can be used to address capacity and energy issues arising from the coal retirements announced or likely in the site plan docket. Thus, in its 2013 Ten-Year Site Plan Review, the PSC could profitably evaluate the several different scenarios post-retirement, including scenarios in which capacity is replaced with more aggressive demand side measures. Other scenarios should also, of course, explore the potential of other energy sources, including enhanced in-state renewables, including solar, and out-of-state PPAs for renewable (and hence zero fuel cost) energy. In the FEECA process, meanwhile, the PSC can consider the costs and benefits of such measures, especially as compared with costly and risky new gas capacity. The two processes can and should reinforce each other as the PSC works to find ways to minimize risks and costs to ratepayers.

III. Conclusion

Last year, we cautioned that a significant amount of coal-fired capacity in Florida was set for retirement. That process has continued. To manage any ratepayer risk from these retirements and the possible over-dependence on natural gas which they may promote, the PSC should emphasize demand-side management options as alternatives to gas-fired capacity. We look forward to working with the Commission to ensure that Florida ratepayers secure healthier air and a more reliable and efficient electricity system.

Sincerely,

[3] Available at: http://aceee.org/energy-efficiency-sector/state-policy/aceee-state-scorecard-ranking.

Craig Segall
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July 2, 2012

Phillip O. Ellis
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CC: Traci Matthews
tmatthews@psc.state.fl.us

Re: Comments on Gulf Power's Ten-Year Plan Submittal

Dear Mr. Ellis and Ms Matthews:

Thank you for accepting these comments on behalf of the Sierra Club and its more than 27,000 Florida members, and on behalf of Earthjustice. We look forward to participating in the Public Service Commission (PSC)'s Ten-Year Plan review process. We are writing to help inform the Commission of serious regulatory risks which should be addressed in this Ten-Year Plan.

As you know, Ten-Year Plans are designed to provide a broad overview of a utility's "power-generating needs and the general location of its proposed power plant sites;" accordingly, plans must be "suitable" for planning purposes. F.S. § 186.801; *see also* F.A.C. §§ 25-22.070 & 25-22.071. These plans are among the many tools used by the Commission as it fulfills its statutory responsibilities to maintain "sufficient, adequate, and efficient service" and "fair and reasonable rates" for all Floridians. *See, e.g.*, F.S. § 366.03.

To do so, the Commission will have to address the implications of substantial new environmental compliance obligations at several aging coal-fired units. A recent report for state utility commissioners, primarily authored by former Colorado PSC Chair Ron Binz, puts the problem succinctly, reminding regulators that "[t]he U.S. electric utility industry, which has remained largely stable and predictable during its first century of existence now faces tremendous challenges," including the prospect of substantial retirements of aging coal-fired power plants. *See* Ron Binz & CERES, *Practicing Risk-Aware Electricity Regulation: What Every State Regulator Needs to Know* (2012) at 5.[1] These "retrofit or retire" decisions will lead to significant changes in the Florida coal fleet, and the PSC will be charged with managing these shifts. As Commissioner Binz writes:

> The question for regulators is whether to approve coal plant closures in the face of new and future EPA regulations, or to approve utility investments in costly pollution controls to keep the plants running. Regulators should treat this much like an IRP proceeding: utilities

[1] Attached as Ex. 1.

> should be required to present multiple scenarios differing in their disposition of the coal plants. The cost and risk of each scenario should be tested using sensitivities for fuel costs, environmental requirements, cost of capital, and so forth. In the end, regulators should enter a decision that addresses all of the relevant risks.

Id. at 9.

These comments highlight some of these important risks. The Commission should use the Ten-Year Plan informational docket to fully investigate them. We have submitted similar comments addressing plans filed by several different utilities; this filing focuses on coal-fired power plants operated by Gulf Power.

I. Gulf Power's Plants Face Substantial Environmental Compliance Costs

Gulf Power's Lansing Smith, Crist, and Scholz plants are aging facilities lacking major pollution controls. These plants are an increasingly bad deal for ratepayers: In addition to posing a serious threat to public health, they are not economic to operate. As utilities and PSCs around the country are increasingly recognizing, rising pollution control and fuel costs make coal power an unattractive proposition, especially as energy efficiency, demand-side resources, and renewable power become ever more available and as natural gas prices continue at record lows. Multi-million dollar life-extension projects for aging coal plants are not prudent in these circumstances. Accordingly, Gulf anticipates that it is likely to retire many of its plants in the near future. Gulf Power Ten Year Plan ("Gulf Plan") at 3.

Because Gulf's plans have important implications for the "need … for electrical power" in its service territory, and for how that need is to be met, as well on "fuel diversity within the state," on the "environmental impact" of any proposed replacement power, and on the state "comprehensive plan," *see* F.S. § 186.801, the Commission should ensure that Gulf discloses its intentions in its Ten-Year Plan as fully as possible. It is particularly important to do so because Gulf will face compliance obligations within the next few years that will lead to retirement decisions. The Commission can best protect Floridians by beginning the planning process for these likely retirements now. The Plan is not suitably detailed to allow for this planning to be successful, so, at the end of these comments, we respectfully urge the PSC to require Gulf to submit critical additional information.

Gulf Power's Lansing Smith and Scholz plants are the most likely retirement targets because both plants lack "scrubbers," the flue-gas desulfurization systems required to remove SO_2, which can cause deadly respiratory damage, and other acid gases from their emissions. Scrubber systems for these plants would cost hundreds of millions of dollars. Such an investment, and the corresponding rate increase, would not be prudent when much cheaper sources of power are available. Accordingly, the Commission should work with Gulf Power to investigate retirement options for these plants.

In the discussion below, we explain the likely sources of scrubber liability for the Lansing Smith and Scholz plants, before briefly highlighting the many other environmental compliance costs which Gulf is likely to face.

A. Likely Scrubber Liability for Gulf Power Facilities

Three separate environmental and public health protection programs are likely to drive scrubber installation requirements, and hence "retire or retrofit" decisions, at the Lansing Smith and Scholz facilities: the SO_2 National Ambient Air Quality Standards ("NAAQS"), 40 C.F.R. § 50.17, the Mercury and Air Toxics Standards ("MATS"), 40 C.F.R. Subpt. UUUUU, and the Regional Haze Rule, 40 C.F.R. § 51.308.

i. The SO_2 NAAQS

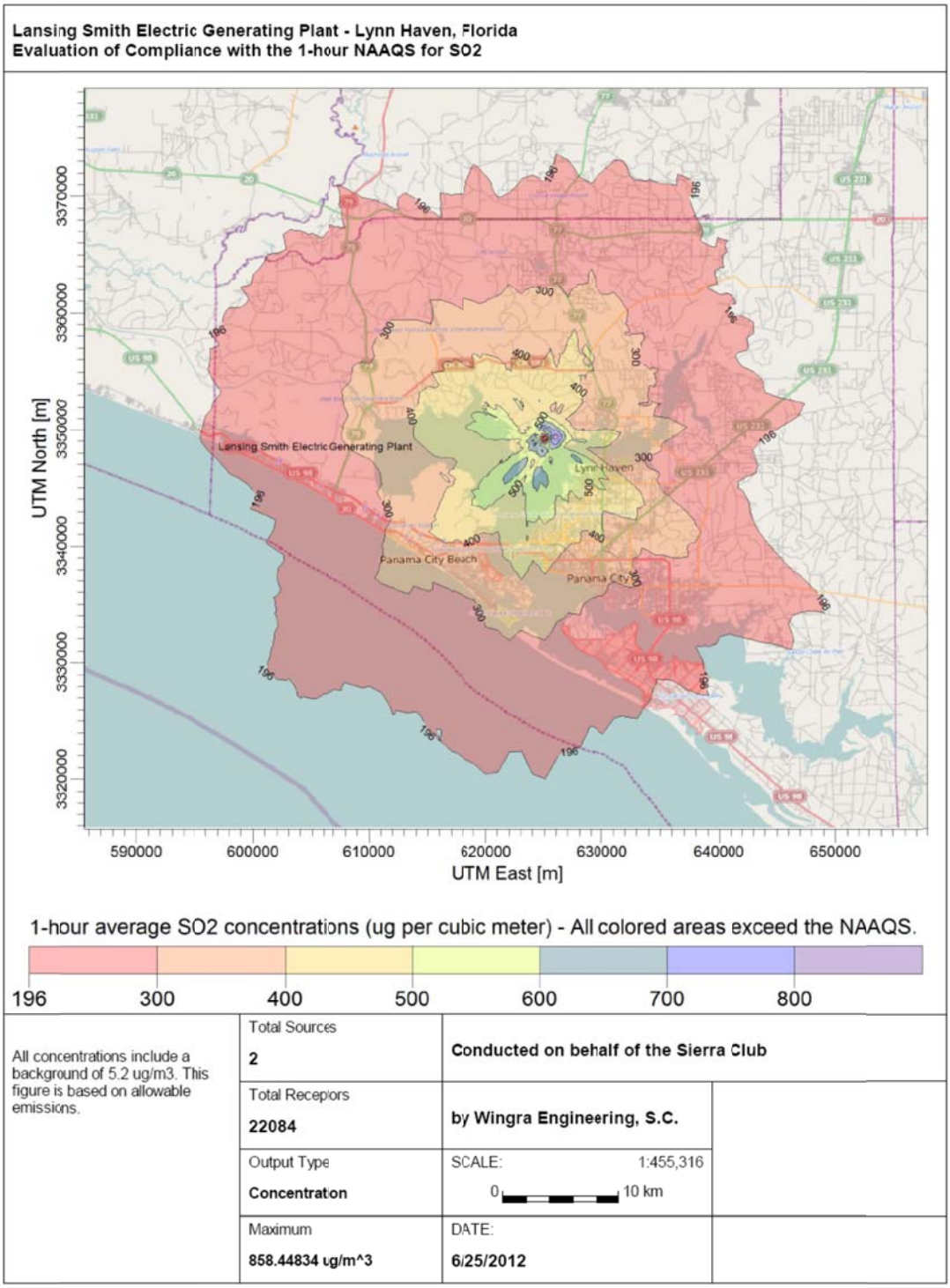
Just five minutes of exposure to SO_2 can make people sick; in fact, the causal link between this pollution and asthma attacks and other respiratory problems is the "strongest" such link which the EPA's scientific advisory board can identify. 75 Fed. Reg. 35,520, 35,525 (June 22, 2010). To protect the public from such pollutants, EPA is required to set NAAQS specifying the safe level of public exposure; states then develop state implementation plans (SIPs) to ensure that those standards are attained. *See* 42 U.S.C. §§ 7409 & 7410. EPA's decision to protect public health by lowering the NAAQS for SO_2 to a maximum allowable exposure of 75 ppb (a concentration equivalent to 196.2 $\mu g/m^3$) over an hour, *see* 75 Fed. Reg. 35,520 (June 22, 2010), thus obliges Florida to update its SIP to ensure that its citizens are protected from this dangerous air pollution.

States are generally required to submit updated SIPs "within 3 years" after EPA updates a NAAQS; because EPA finalized its NAAQS in 2010, Florida's plan is due in 2013. 42 U.S.C. § 7410(a)(1). The plan must "provide[] for implementation, maintenance, and enforcement of" the standard throughout Florida. *Id.* Although EPA's approval and review process may delay plan implementation for a year or two after submission, the Commission can reasonably expect Florida's SIP to be operating by 2015 or before.

This tight timeline is directly relevant to the Commission's review of Gulf Power's plans because the Lansing Smith plant is causing violations of the NAAQS, and so will have to install controls under any legal SIP. Sierra Club engaged an expert air modeler, Steve Klafka of Wingra Engineering, to evaluate the plant's compliance with the NAAQS, using EPA's models and methodology.[2] We modeled both the plant's allowable emissions – those authorized by its Title V Air Operation Permit, No. 0050014-018-AV – and its maximum emissions in 2011, the most recent year with complete data in EPA's Air Pollution Markets Database. Whether measured by its permit or by its most recent maximum emissions, the plant causes the pollution in the air over Panama City to reach unsafe levels, violating the NAAQS several-fold.

[2] The methodology is described in detail in the attached report, Ex. 2.

The figure below shows the SO_2 pollution plume the plant would create when operating at its permit limits. All colored areas violate the NAAQS. While the NAAQS is set at 196.2 µg/m^3, Lansing Smith's permit allows pollution levels to soar to 858.4 µg/m^3, over 400% of the safe value; even a bit further away from the plant, pollution directly over downtown Panama City reaches levels close to double the safe value.



Importantly, Lansing Smith causes NAAQS violations even when operating below its permitted maximums. Last year, Lansing Smith's highest operating hour emissions saw SO_2 concentrations reach 346.5 $\mu g/m^3$, which is nearly double the safe value. *See* Ex. 2 at Table 1.

Indeed, Lansing Smith's SO_2 emissions are so extreme that, according to the Florida Department of Environmental Protection ("FL DEP"), they even violate the far more lenient NAAQS that the new standard replaces. *See* FL DEP Permit No. 0050014-018-AV at 5. As such, FL DEP requires Gulf Power to post no trespassing signs to "protect the general public" from crossing the plant's fence line, within which the pollution is the most intense. *See id.* This is not a safe facility.

To reduce this illegal pollution, Lansing Smith would have to cut total facility emissions by 77.6% from its current permit. *Id.* at Table 3. To do so, it is highly likely to have to install a scrubber, thereby confronting hundreds of millions in control costs, which we document more fully below. Importantly, these costs will be far outweighed by public health benefits. EPA determined that the NAAQS will produce on the order of $36 billion in *net* benefits once safe levels of SO_2 have been attained. 75 Fed. Reg. at 35,588. Panama City residents will secure a substantial portion of these benefits – in the form of fewer asthma attacks, emergency room visits, and premature deaths – once Lansing Smith's pollution has been controlled.

We have not yet modeled the Scholz facility, but it is also an unscrubbed coal boiler, burning high-sulfur bituminous coal, and its permitted emissions are far higher than Lansing Smith's. While the Lansing Smith permit allows emissions of up to 4.50 lbs/MMBtu of SO_2, FL DEP Permit No. 0050014-018-AV at 8, the Scholz permit allows the facility to emit up to an astonishingly 6.17 lbs/MMBtu, FL DEP Permit No. 0630014-010-AV at 6. FL DEP candidly acknowledges that this emission rate "indicates exceedances" near the facility of even the more lenient NAAQS which EPA has since replaced, and so requires Gulf Power to take "precautions… to preclude public access." *Id.* Scholz is an even dirtier plant than Lansing Smith, and so is very likely to run afoul of the new NAAQS as well.

In short, the SO_2 NAAQS, a pollution control requirement which Gulf Power does not even acknowledge in its Ten-Year Plan, is highly likely to require the Lansing Smith and Scholz facilities to retrofit or retire. It is not the only requirement to do so, as we next discuss.

ii. MATS Requirements

In the Clean Air Act of 1990, Congress ordered EPA to investigate hazardous air pollutants emitted by power plants, and to promulgate emissions standards for these pollutants if they threatened public health. 42 U.S.C. § 7412(n)(1). Because coal power plants are dominant sources of mercury, acid gases, and other highly toxic pollutants, EPA was obligated to issue such standards, and finally did so in 2012, 22 years later. *See* 77 Fed. Reg. 9,304 (Feb. 16, 2012).

The final MATS rule issued in response to this Congressional mandate requires operators to control mercury and acid gases. A smoke stack scrubber can be required to comply with EPA's control requirements. In EPA's analysis of facility compliance options, it presumed that coal plants emitting more than 2 lbs/MMBtu of SO_2 would have to install scrubbers to comply with the standard. 77 Fed. Reg. at 9,412. As we note above, Lansing Smith emits more than twice this amount, and Scholz emits *three times* this threshold quantity. As such, scrubbers will very likely be required at these plants in order to comply with MATS.

The Clean Air Act requires that existing sources comply with MATS "as expeditiously as practicable, but in no event later than 3 years after the effective date" of the standard. 42 U.S.C. § 7412(i)(3). Because MATS was promulgated and effective on February 16, 2012, plants must comply by that date in 2015. Although limited compliance extension of up to 1-2 additional years may be available in some limited circumstances, *see id.*, these extensions are disfavored.

Accordingly, as Gulf Power recognizes, MATS "may severely restrict Gulf's coal-fired generation or completely eliminate the generation produced by Gulf's coal-fired units at Plants Smith and Scholz by as early as 2015." Gulf Plan at 3.

iii. Regional Haze Requirements

Since 1977, the Clean Air Act has required EPA and the states to make "reasonable progress" towards restoring natural visibility in Class I areas – which are essentially national parks and wildernesses. *See* 42 U.S.C. § 7491. EPA's rules to address regional haze, promulgated in 1999, are now being implemented. Florida is the process of a SIP revision intended to protect Class I areas affected by sources in the state. *See* FL DEP, *Regional Haze Plan for Florida Class I Areas* (Draft as amended May 2012).[3] Gulf Power has already determined that this rule, alone, may lead it to retire the Lansing Smith facility.

The regional haze rule requires that Florida impose controls at all sources of visibility-impairing pollutants to the extent such controls will be needed to make reasonable progress towards restoring natural visibility by 2064. *See* 40 C.F.R. § 51.308(d)(3). The Act and the Rule also require sources which were in existence by August 7, 1977, but which had not been in operation before August 7, 1962, to install "the best available retrofit technology" (BART) to control visibility-impairing pollutants. 42 U.S.C. § 7491(b)(2)(A) & 40 C.F.R. § 51.308(e). FL DEP has determined that the Crist facility is subject to reasonable progress analysis and that Lansing Smith is subject to BART. *See* FL Draft Regional Haze Plan at 98 & 102.

FL DEP had planned to rely upon a separate EPA SO_2 trading program, the Clean Air Interstate Rule ("CAIR") to address these requirements, but CAIR has been replaced with a new program which does not control SO_2 in Florida. *See* 77 Fed. Reg. 31,240, 31,248 (May 25, 2012). As such, FL DEP is reanalyzing control options and will have to consider source-specific control

[3] Available at http://www.dep.state.fl.us/air/rules/regulatory/regional_haze_imp.htm.

requirements for Crist and Lansing Smith. Scholz should also be implicated in this re-analysis because FL DEP had previously excluded relatively small facilities largely because it assumed CAIR would address most SO_2 emissions. Now that CAIR is no longer available, Scholz will have to be analyzed as well. Thus, as a result of these analyses, FL DEP will have to address SO_2 emissions, in some fashion, from all of Gulf Power's coal plants.

These controls are likely to drive scrubber requirements (and other controls or operating restrictions at scrubbed plants like Crist) because, according to FL DEP, SO_2 is the dominant source of visibility-impairing pollution in Florida. *See, e.g.*, FL Draft Regional Haze Plan at 91-92. Thus, these rules, too, are highly likely to drive scrubber requirements at the Lansing Smith facility.

Gulf Power has admitted as much to FL DEP. In a "BART Implementation Plan" submitted to DEP on May 21, 2012[4], it indicated that it will complete a BART analysis for Lansing Smith, and that it will decide, by January 1, 2015, whether to install a scrubber on the plant by 2018 (or later), "commit to retire the operation of Smith Unit 1 by January 1, 2022 and Smith Unit 2 before January 1, 2021," or to seek permit levels by 2015 reducing plant operations below BART emissions limits. Gulf BART Plan at 2. Because BART determinations will be approved within the next year, it is not at all clear how Gulf Power expects to run its plants until the early 2020s. Retirement within the next few years is the more likely option.

iv. Scrubber Costs

We have calculated the approximate cost of installing and running scrubbers (at 90% efficiency, a level which would likely be required, at a minimum, to meet the requirements of all three relevant rules) at Lansing Smith and Scholz, based upon the EPA's Integrated Planning Model and a scrubber-focused appendix developed by Sargent & Lundy.[5] This model predicts that the capital costs for fitting Lansing Smith Units 1 and 2 with scrubbers at $234 million. The incremental costs (including running costs) of these upgrades would be $43.1/MWh annually. Gulf Power would no doubt seek to pass these costs on to rate-payers if it opted to continue to run the plant, rather than to retire it.

Scrubber costs for Scholz are also very high. Using the same government modeling, we calculated that scrubbers for Scholz units 1 & 2 would cost $106 million to install, yielding a $243.5/MWh spike in incremental costs.

These figures do not include the incremental costs of effluent controls for scrubber waste. Any such additional upgrades would, of course, add to these costs, as would any additional measures required at Crist to bring that facility into compliance. The expenditures are extraordinarily high simply in order to extend the lives of these decades-old, expensive, coal-fired power plants. Gulf Power is unlikely to make them and, we submit, it would not be

[4] Attached as Ex. 3.
[5] All modeling parameters can be found at http://www.epa.gov/airmarkt/progsregs/epa-ipm/BaseCasev410.html.

appropriate for the Commission to authorize such costs where less expensive options are available.

B. Other Environmental Liabilities

As Gulf Power acknowledges, Gulf Plan at 3, scrubber costs are not the only liabilities it faces. There are also pending rules requiring upgrades to coal plant cooling water systems, *see* 76 Fed. Reg. 22,174 (Apr. 20, 2011), better handling and disposal practices for coal combustion waste, *see* 75 Fed. Reg. 35,128 (June 21, 2010), and new treatment systems for liquid effluent discharges,[6] all of which are likely to be finalized in the next two years. EPA is also updating the NAAQS for particulate matter and for ozone. Moreover, EPA has recently proposed carbon controls for new electricity generating units. *See* 77 Fed. Reg. 22,39 (Apr. 13, 2012). Once finalized, these rules will obligate EPA to extend carbon controls to existing facilities, including Gulf Power's fleet. *See* 42 U.S.C. § 7411(d). The cumulative impact of these liabilities on Gulf Power will be large. Indeed, according to Gulf, "the additional costs to comply with the final versions of EPA's proposed water quality and coal combustion by-product rules" alone "may result in total combined compliance costs that render controlled coal-fired operations uneconomical in the long term." Gulf Plan at 3.

Coal ash costs will be particularly pressing for Gulf Power. According to the Toxic Release Inventory, its Lansing Smith facility discharged 520,281 pounds of ash to its impoundment in 2006, a typical year, making Lansing Smith the 57th largest source of ash in the country and the second largest sources in Florida.[7] Highly troublingly, carcinogenic hexavalent chromium, which leaches from coal ash, has been found in groundwater wells near Lansing Smith at over 5,000 times safe levels (as determined by California for its drinking water goals), and above federal standards.[8] Clean-up costs for this contamination, including halting wet storage of ash, will be yet another substantial expense for the plants.

C. Likely Retirements

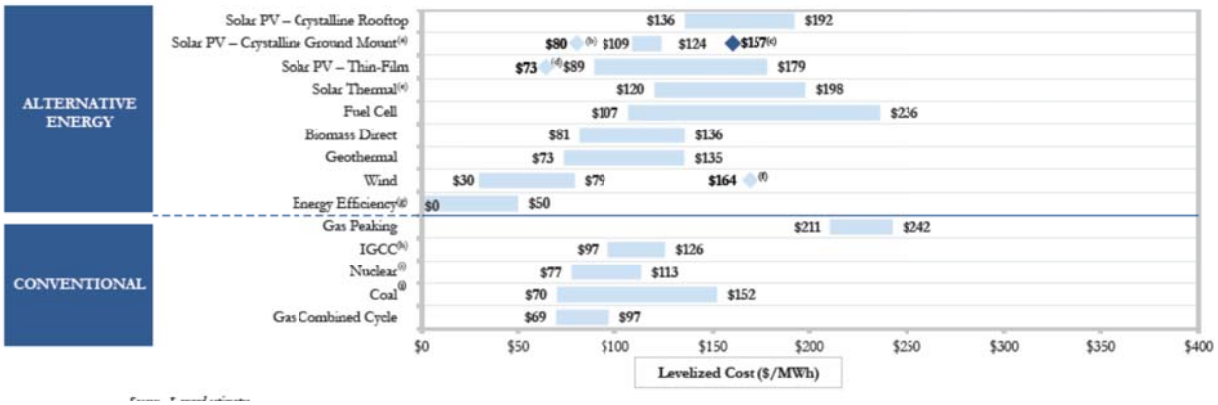
The cumulative compliance costs from all the rules which apply to Gulf Power's fleet are very large. Upon reviewing them, and considering the wide availability of more inexpensive power sources, Gulf Power is highly likely to follow industry trends towards coal retirement.

Coal use is falling quickly, in response both to the cost of pollution controls and to national economic trends, including the growth of inexpensive wind power and the boom in shale gas production. As EPA has recently documented, "all indications suggest that very few new coal-fired power plants will be constructed in the foreseeable future." 77 Fed. Reg. at 22,413, and the Energy Information Administration (EIA) is documenting increasing retirements of existing plants. In particular, the EIA's Annual Energy Outlook for 2012 forecasts no new unplanned

[6] *See* EPA's plans for this rule at http://water.epa.gov/scitech/wastetech/guide/steam_index.cfm
[7] *See* Ex. 4, attached.
[8] Lisa Evans, *EPA's Blind Spot: Hexavalent Chromium in Coal Ash* (2011) at 6, attached as Ex. 5.

coal capacity through 2020. RIA at 5-5. EIA's most recent Electric Power Monthly report confirms that this trend continues. Thus far this year, *none* of the 5,627 MW of new units to come online are coal-fired; instead, new capacity additions are largely in renewable power or natural gas. EIA, *Electric Power Monthly June 2012* at Table ES3.[9] Conversely, retirements to date have been predominantly coal-fired units. *See id.* at Table ES4. Utilities across the country have announced thousands of megawatts worth of coal retirements over the last few years.[10]

Industry-wide levelized cost figures compiled by independent analysts demonstrate why these retirements are occurring. The most recent (2011) edition of Lazard's Levelized Cost of Energy Analysis,[11] a widely-used reference, shows that energy efficiency, wind, and natural gas combined cycle levelized costs are already below those of coal, as the figure below demonstrates.



Under these circumstances, prudent operators are increasingly deciding not to impose additional costs on their ratepayers by running coal-fired units with costly new pollution technology. Instead, they are opting to retire older units and pursue cleaner, cheaper, energy options. Gulf Power could, and should, decide to follow the same course.

D. Recommended Commission Action

Although Gulf Power has acknowledged that some retirements may occur, it nonetheless "assume[s]" that Lansing Smith and Scholz "will be available to operate on coal throughout the 2012-2021 planning cycle." Gulf Plan at 3. As we have demonstrated above, this assumption is

[9] Available at: http://205.254.135.7/electricity/monthly/pdf/epm.pdf.

[10] *See, e.g.*, Progress Energy Press Release, "Progress Energy Carolinas to retire coal power plant ahead of schedule" (Apr. 1, 2011) (recording the retirement of four North Carolina coal plants), available at https://www.progress-energy.com/company/media-room/news-archive/press-release.page?title=Progress+Energy+Carolinas+to+retire+coal+power+plant+ahead+of+schedule&pubdate=04-01-2011; FirstEnergy Press Release, "FirstEnergy, Citing Impact of Environmental Regulations, Will Retire Six Coal-Fired Power Plants" (Jan. 29, 2012) (announcing the retirement of six coal plants in Ohio), available at https://www.firstenergycorp.com/content/fecorp/newsroom/news_releases/firstenergy_citingimpactofenvironmentalregulationswillretiresixc.html; Environment News Service, "Dominion Virginia to Replace Coal Plants with Gas, Nuclear" (Sept. 7, 2011) (documenting retirement of two Virginia coal plants), available at http://www.ens-newswire.com/ens/sep2011/2011-09-07-091.html.

[11] Attached as Ex. 6.

arbitrary and unsupportable: The compliance periods for the scrubber-forcing rules will run within the next two years and retirements will very likely occur within that period, and certainly will occur within the next decade. This error, and Gulf Power's failure fully to address the impacts of retirements upon its system and upon ratepayers, renders the draft plan "unsuitable" as a planning document. *See* F.S. §186.801. The Commission, "may suggest alternatives to the plan," *id.*, however, and may classify a plan as suitable upon the submission of "additional data," *see* F.A.C. § 25-22.071(5). We respectfully request that the PSC exercise its authority to ensure that Gulf Power's plan provides adequate data to allow the PSC and the public to address these plant retirements.

Specifically, we submit that the Commission should seek the following information from Gulf Power and require resubmission of a complete plan addressing these submissions:

1. The utility should provide an analysis of all environmental compliance obligations which it will experience at all of its coal-fired facilities. For each requirement, the utility should cite the relevant rule, explain how it is likely to apply to the plant, the likely costs of compliance to the utility and to ratepayers, and the timeline on which compliance will be required. The utility should also document any steps it has taken to address these compliance obligations, and alternative steps it might take. For instance, if the utility anticipates that it will have to install a scrubber to comply with MATS, it should report to the Commission on scrubber installation and operation costs, whether it has contracted to purchase a scrubber and on what timeline, and what other options it has considered. *See* F.S. § 186.801 (requiring utilities to document "[p]ossible alternatives to the proposed plan").

2. The utility should provide a comparative analysis of compliance costs and the cost costs of replacing the plant's power through energy efficiency, demand response, power purchase agreements, new generation facilities, or other means. *See* F.S. §186.801 (requiring utilities to explain the impact of their plans on fuel diversity and on the need for electric power in their regions). In light of this analysis, the utility should indicate whether it intends to retire any facility, and on what timeline, and the relative costs of retirement versus those of other options. If retirement has not been selected but is being considered, the utility should indicate when the decision will be made.

3. For any facility where retirement is possible, the utility should discuss how it intends to address any reliability issues which may be caused by the retirement. The Commission should play an active role in this regard, as it must maintain reliability of the electric grid. *See* F.S. § 366.05(7)-(8) (authorizing the Commission to "require reports from all electric utilities to assure the development of adequate and reliable energy grids" and to order "installation and repair of necessary facilities" to address reliability issues"). The Commission has determined that "[r]eserve margins in Florida typically remain well above" relevant minimums through 2020, so system-wide resource adequacy problems are unlikely, but the Commission may still need to

address localized reliability issues. If such problems appear to be present, the Commission should work proactively and transparently with the Florida Reliability Coordinating Council to address them well in advance of any planned retirement.

We appreciate this careful consideration of Gulf Power's environmental compliance options, and any resulting plant retirements, and remind the Commission that such thorough analysis is required to ensure that the Ten-Year Plan complies with legal requirements. We request that the Commission share the results of its inquiry with us and with the public, and request formal notice of the Commission's next steps.

Please contact the undersigned with any concerns or questions.

Sincerely,

s/ Craig Holt Segall

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July 2, 2012

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CC: Traci Matthews
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Re: Comments on Progress Energy's Ten-Year Plan Submittal

Dear Mr. Ellis and Ms Matthews:

Thank you for accepting these comments on behalf of the Sierra Club and its more than 27,000 Florida members, and on behalf of Earthjustice. We look forward to participating in the Public Service Commission (PSC)'s Ten-Year Plan review process. We are writing to help inform the Commission of serious regulatory risks which should be addressed in this Ten-Year Plan.

As you know, Ten-Year Plans are designed to provide a broad overview of a utility's "power-generating needs and the general location of its proposed power plant sites;" accordingly, plans must be "suitable" for planning purposes. F.S. § 186.801; *see also* F.A.C. §§ 25-22.070 & 25-22.071. These plans are among the many tools used by the Commission as it fulfills its statutory responsibilities to maintain "sufficient, adequate, and efficient service" and "fair and reasonable rates" for all Floridians. *See, e.g.*, F.S. § 366.03.

To do so, the Commission will have to address the implications of substantial new environmental compliance obligations at several aging coal-fired units. A recent report for state utility commissioners, primarily authored by former Colorado PSC Chair Ron Binz, puts the problem succinctly, reminding regulators that "[t]he U.S. electric utility industry, which has remained largely stable and predictable during its first century of existence now faces tremendous challenges," including the prospect of substantial retirements of coal-fired power plants. *See* Ron Binz & CERES, *Practicing Risk-Aware Electricity Regulation: What Every State Regulator Needs to Know* (2012) at 5.[1] These "retrofit or retire" decisions will lead to significant changes in the Florida coal fleet, and the PSC will be charged with managing these shifts. As Commissioner Binz writes:

> The question for regulators is whether to approve coal plant closures in the face of new and future EPA regulations, or to approve utility investments in costly pollution controls to keep the plants running. Regulators should treat this much like an IRP proceeding: utilities

[1] Attached as Ex. 1.

should be required to present multiple scenarios differing in their disposition of the coal plants. The cost and risk of each scenario should be tested using sensitivities for fuel costs, environmental requirements, cost of capital, and so forth. In the end, regulators should enter a decision that addresses all of the relevant risks.

Id. at 9.

These comments highlight some of these important risks. The Commission should use the Ten-Year Plan informational docket to fully investigate them. We have submitted similar comments addressing plans filed by several different utilities; this filing focuses on coal-fired power plants operated by Progress Energy.

I. Progress Energy's Crystal River Plant Face Substantial Environmental Compliance Costs

Units 1 and 2 at Progress Energy's Crystal River plant were put into service in the late 1960s, and are operating without major pollution controls, including smokestack scrubbers. *See* FL DEP Air Operation Permit No. 0170004-025-AV (2011) at 6. These units are an increasingly bad deal for ratepayers: In addition to posing a serious threat to public health, they are not economic to operate. As utilities and PSCs around the country are increasingly recognizing, rising pollution control and fuel costs make coal power an unattractive proposition, especially as energy efficiency, demand-side resources, and renewable power become ever more available and as natural gas prices continue at record lows. Multi-million dollar life-extension projects for aging coal plants are not prudent in these circumstances. Progress has already told FL DEP that it will consider retiring units 1 and 2 within the next decade. *See* Progress Energy BART Implementation Plan for Crystal River Units 1 and 2 (June 2012) at 3.[2] Yet, Progress's Ten-Year Plan does not even mention these units, much less address their retirements.

Because of this striking gap, Progress's plan is not "suitable" for planning purposes. *See* F.S. § 186.801. The likely retirement of the Crystal River units has important implications for the "need … for electrical power" in its service territory, and for how that need is to be met, as well on "fuel diversity within the state," the "environmental impact" of any proposed replacement power, and the state "comprehensive plan." *See* F.S. § 186.801. The Commission should therefore ensure that Progress submits a corrected plan which discloses its intentions as fully as possible. It is particularly important to do so because Progress will face compliance obligations within the next few years that will lead to retirement decisions. The Commission can best protect Floridians by beginning the planning process for these likely retirements now.

Crystal River Units 1 and 2 are likely retirement targets because both units lack "scrubbers," the flue-gas desulfurization systems required to remove SO_2, which can cause deadly respiratory damage, from their emissions. Scrubber systems for these plants would cost tens of millions of dollars. Such an investment, and corresponding rate increase, would not be prudent

[2] Attached as Ex. 2.

when much cheaper sources of power are available. Accordingly, the Commission should work with Progress Energy to investigate retirement options for these plants.

In the discussion below, we explain the likely sources of scrubber liability for Crystal River, before briefly highlighting the many other environmental compliance costs which Progress is likely to face.

A. Likely Scrubber Liability for Crystal River Units 1 and 2

Three separate environmental and public health protection programs are likely to drive scrubber installation requirements, and hence "retire or retrofit" decisions, at Crystal River: the SO_2 National Ambient Air Quality Standards ("NAAQS"), 40 C.F.R. § 50.17, the Mercury and Air Toxics Standards ("MATS"), 40 C.F.R. Subpt. UUUUU, and the Regional Haze Rule, 40 C.F.R. § 51.308.

i. The SO_2 NAAQS

Just five minutes of exposure to SO_2 can make people sick; in fact, the causal link between this pollution and asthma attacks and other respiratory problems is the "strongest" such link which the EPA's scientific advisory board can identify. 75 Fed. Reg. 35,520, 35,525 (June 22, 2010). To protect the public from such pollutants, EPA is required to set NAAQS specifying the safe level of public exposure; states then develop state implementation plans (SIPs) to ensure that those standards are attained. *See* 42 U.S.C. §§ 7409 & 7410. EPA's decision to protect public health by lowering the NAAQS for SO_2 to a maximum allowable exposure of 75 ppb (a concentration equivalent to 196.2 $\mu g/m^3$) over an hour, *see* 75 Fed. Reg. 35,520 (June 22, 2010), thus obliges Florida to update its SIP to ensure that its citizens are protected from this dangerous air pollution.

States are generally required to submit updated SIPs "within 3 years" after EPA updates a NAAQS; because EPA finalized its NAAQS in 2010, Florida's plan is due in 2013. 42 U.S.C. § 7410(a)(1). The plan must "provide[] for implementation, maintenance, and enforcement of" the standard throughout Florida. *Id.* Although EPA's approval and review process may delay plan implementation for a year or two after submission, the Commission can reasonably expect Florida's SIP to be operating by 2015 or before.

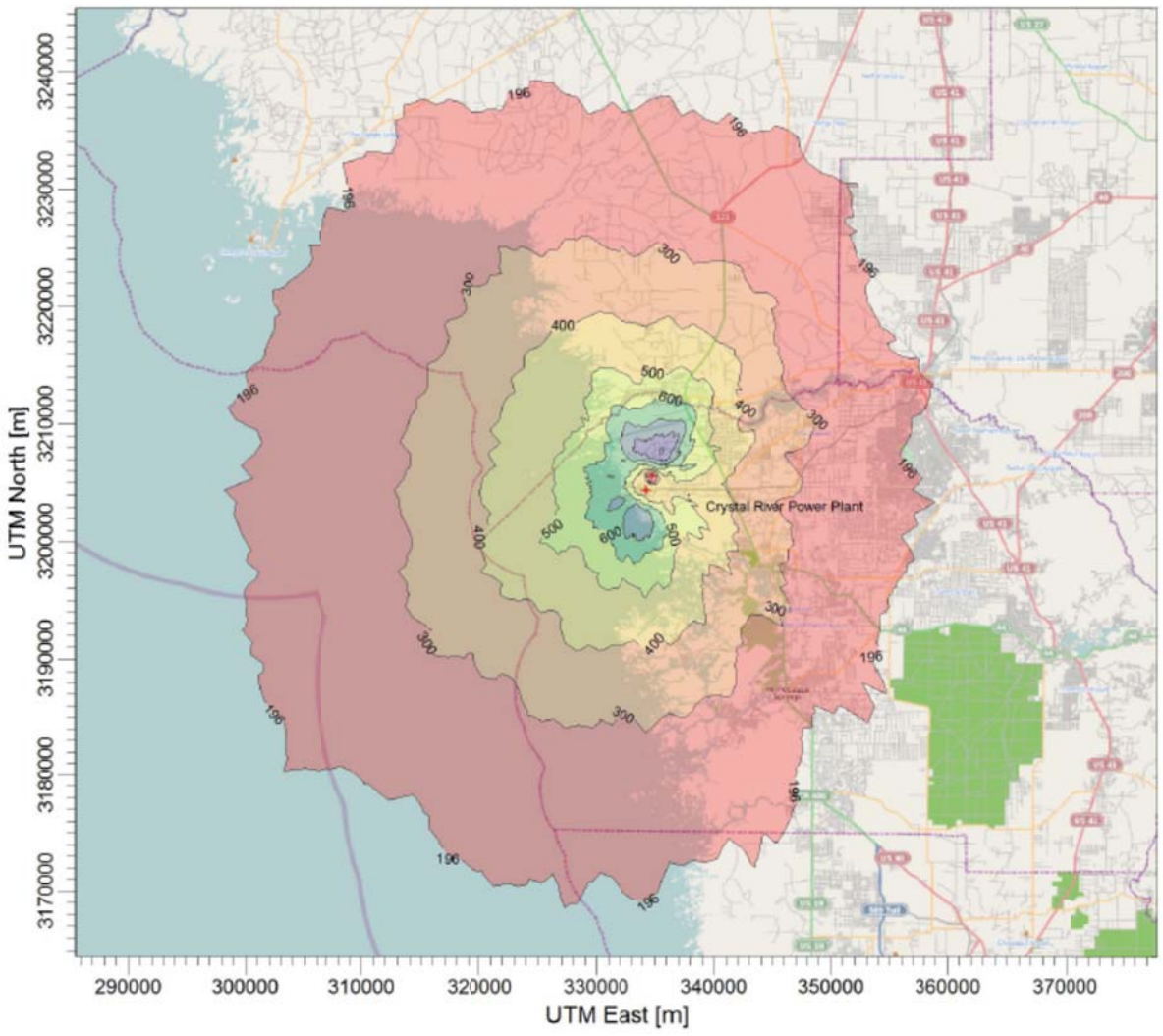
This tight timeline is directly relevant to the Commission's review of Progress Energy's plans because the Crystal River plant is causing violations of the NAAQS, and so will have to install controls under any legal SIP. Sierra Club engaged an expert air modeler, Steve Klafka of Wingra Engineering, to evaluate the plant's compliance with the NAAQS, using EPA's models and methodology.[3] We modeled both the plant's allowable emissions – those authorized by its Title V Air Operation Permit, No. 017000–025-AV, and its maximum emissions in 2011, the most recent year with complete data in EPA's Air Pollution Markets Database. Whether measured by

[3] The methodology is described in detail in the attached report, Ex. 3.

its permit or by its most recent maximum emissions, the plant causes pollutants in the air near Crystal River to reach dangerous levels.

The figure below shows the SO_2 pollution plume the plant would create when operating at its permit limits. All colored areas violate the NAAQS. While the NAAQS is set at 196.2 μg/m^3, Crystal River's permit allows pollution levels to soar to a maximum of 921.0 μg/m^3, over 460% of the safe value; even a bit further away from the plant, the pollution in the air directly over residential areas and over Crystal Bay is well above safe levels.

Crystal River Power Plant - Crystal River, Florida
Evaluation of Compliance with the 1-hour NAAQS for SO2



1-hour average SO2 concentrations (ug per cubic meter) - All colored areas exceed the NAAQS.

196 300 400 500 600 700 800 900

All concentrations include a background of 5.2 ug/m3. This figure is based on allowable emissions.	Total Sources **6**	**Conducted on behalf of the Sierra Club**	
	Total Receptors **22083**	**by Wingra Engineering, S.C.**	
	Output Type **Concentration**	SCALE: 1:580,926 0 20 km	
	Maxmum **921.02714 ug/m^3**	DATE: **6/25/2012**	

Importantly, Crystal River causes NAAQS violations even when operating below its permitted maximums. Last year, the plant's highest operating hour emissions saw SO_2 concentrations reach 534.6 $\mu g/m^3$, which is nearly three times the safe value. *See* Ex. 2 at Table 1.

To reduce this illegal pollution, Crystal River would have to cut total facility emissions by 79.1% from its current permit. *Id.* at Table 3. To do so, it is highly likely to have to install a scrubber, thereby confronting hundreds of millions in control costs, which we document more fully below. Importantly, these costs will be far outweighed by public health benefits. EPA determined that the NAAQS will produce on the order of $36 billion in *net* benefits once safe levels of SO_2 have been attained. 75 Fed. Reg. at 35,588. Crystal River residents will secure a substantial portion of these benefits – in the form of fewer asthma attacks, emergency room visits, and premature deaths – once the plant's pollution has been controlled.

In short, the SO_2 NAAQS, a pollution control requirement which Progress Energy does not even acknowledge in its Ten-Year Plan, is highly likely to require Crystal River Units 1 and 2 to retrofit or retire. It is not the only requirement to do so, as we next discuss.

ii. MATS Requirements

In the Clean Air Act of 1990, Congress ordered EPA to investigate hazardous air pollutants emitted by power plants, and to promulgate emissions standards for these pollutants if they threatened public health. 42 U.S.C. § 7412(n)(1). Because coal power plants are dominant sources of mercury, acid gases, and other highly toxic pollutants, EPA was obligated to issue such standards, and finally did so in 2012, 22 years later. *See* 77 Fed. Reg. 9,304 (Feb. 16, 2012).

The final MATS rule issued in response to this Congressional mandate requires operators to control mercury and acid gases. A smoke stack scrubber can be required to comply with EPA's control requirements. In EPA's analysis of compliance options, it presumed that coal plants emitting more than 2 lbs/MMBtu of SO_2 would have to install scrubbers to comply with the standard. 77 Fed. Reg. at 9,412. Crystal River's air operation permit allows it to emit 2.1 lbs/MMBtu of SO_2, meaning that the MATS rule will likely drive scrubbers installation at the facility. *See* FL DEP Air Operation Permit 0170003-025-AV at 7. Notably, Crystal River is also the single largest source of mercury in Florida, dumping more than 300 kg of mercury a year into the air around the plant.[4] On both counts, MATS compliance will, accordingly, be a major focus for the facility.

[4] *See* Laura S. Sherman *et al.*, *Investigation of Local Mercury Deposition from a Coal-Fired Power Plant Using Mercury Isotopes*, Environment Science & Technology (2012), attached as Ex. 4.

The Clean Air Act requires that existing sources comply with MATS "as expeditiously as practicable, but in no event later than 3 years after the effective date" of the standard. 42 U.S.C. § 7412(i)(3). Because MATS was promulgated and effective on February 16, 2012, plants must comply by that date in 2015. Although limited compliance extension of up to 1-2 additional years may be available in some limited circumstances, *see id.*, these extensions are disfavored. Accordingly, Progress Energy will have to scrub Crystal River by 2015, or shortly thereafter, or retire the facility, yet it entirely fails to acknowledge this major shift in its operations in its Ten-Year Plan.

iii. Regional Haze Requirements

Since 1977, the Clean Air Act has required EPA and the states to make "reasonable progress" towards restoring natural visibility in Class I areas – which are, essentially, national parks and wildernesses. *See* 42 U.S.C. § 7491. EPA has been very slow to implement this mandatory duty, but its rule to address regional haze, promulgated in 1999, are now being implemented, and Florida is the process of a SIP revision intended to protect Class I areas affected by sources in the state. *See* FL DEP, *Regional Haze Plan for Florida Class I Areas* (Draft as amended May 2012).[5]

The regional haze rule requires that Florida impose controls at all sources of visibility-impairing pollutants to the extent such controls will be needed to make reasonable progress towards restoring natural visibility by 2064. *See* 40 C.F.R. § 51.308(d)(3). The Act and the Rule also require sources which were in existence by August 7, 1977, but which had not been in operation before August 7, 1962, to install "the best available retrofit technology" (BART) to control visibility-impairing pollutants. 42 U.S.C. § 7491(b)(2)(A) & 40 C.F.R. § 51.308(e). FL DEP has determined that the Crist facility is subject to BART. *See* FL Draft Regional Haze Plan at 102.

FL DEP had planned to rely upon a separate EPA SO_2 trading program, the Clean Air Interstate Rule ("CAIR") to address these requirements, but CAIR has been replaced with a new program which does not control SO_2 in Florida. *See* 77 Fed. Reg. 31,240, 31,248 (May 25, 2012). As such, FL DEP is reanalyzing control options and will have to propose source-specific control requirements for Crystal River Units 1 and 2.

These controls are likely to drive scrubber requirements because, according to FL DEP, SO_2 is the dominant source of visibility-impairing pollution in Florida. *See, e.g.*, FL Draft Regional Haze Plan at 91-92. Progress Energy has indicated as much to FL DEP. In a 2009 BART permit, Progress Energy agreed to retire the Crystal River units by December 31, 2020, as long as the second unit of its proposed Levy County nuclear facility was operating by that time.[6] Just a few weeks ago, Progress submitted an updated BART implementation plan to FL DEP indicating that, whether or not the Levy County facility comes online, it would either install a

[5] Available at http://www.dep.state.fl.us/air/rules/regulatory/regional_haze_imp.htm.
[6] *See* Air Permit No. 0170004-017-AC (Feb. 26, 2009) at 6, attached as Ex. 5.

scrubber (by 2018 or 5 years after Florida's haze SIP is approved), retire the units by December 31, 2020, or limit operations to keep the plant's operations below BART limits.[7] Because BART determinations will be approved within the next year, it is not at all clear how Progress expects to run its plants until 2020. Retirement within the next few years is the more likely option.

iv. Scrubber Costs

We have calculated the approximate cost of installing and running scrubbers (at 90% efficiency, a level which would likely be required, at a minimum, to meet the requirements of all three relevant rules) at Crystal River Units 1 and 2, based upon the EPA's Integrated Planning Model and a scrubber-focused appendix developed by Sargent & Lundy.[8] This model predicts that the capital costs for fitting these units with scrubbers as $486 million. The result (including operational costs) would be a $36.6/MWh spike in incremental costs. Progress Energy would no doubt seek to pass these costs on to rate-payers if it opted to continue to run the plant, rather than to retire it. These expenditures are extraordinarily high simply in order to extend the lives of these decades-old, expensive, coal-fired power plants.

B. Other Environmental Liabilities

Scrubber costs are not the only liabilities Crystal River faces. There are also pending rules requiring upgrades to coal plant cooling water systems, *see* 76 Fed. Reg. 22,174 (Apr. 20, 2011), better handling and disposal practices for coal combustion waste, *see* 75 Fed. Reg. 35,128 (June 21, 2010), and new treatment systems for liquid effluent discharges,[9] all of which are likely to be finalized in the next two years. EPA is also updating the NAAQS for particulate matter and for ozone. Moreover, EPA has recently proposed carbon controls for new electricity generating units. *See* 77 Fed. Reg. 22,39 (Apr. 13, 2012). Once finalized, these rules will obligate EPA to extend carbon controls to existing facilities, including Crystal River. *See* 42 U.S.C. § 7411(d). The cumulative impact of these liabilities on Progress Energy will be large and are likely to lend further weight to retirement decisions.

C. Likely Retirements

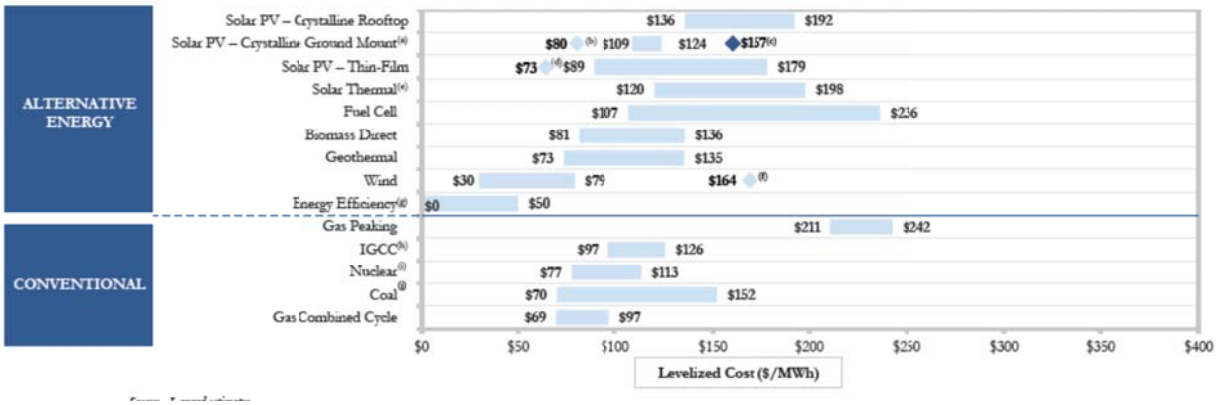
The cumulative compliance costs from all the rules which apply to Progress Energy's Crystal River units are substantial. Upon reviewing them, and considering the wide availability of more inexpensive power sources, Progress is highly likely to follow industry trends towards coal retirement.

Coal use is falling quickly, in response both to the cost of pollution controls and to national economic trends, including the growth of inexpensive wind power and the boom in shale gas production. As EPA has recently documented, "all indications suggest that very few new coal-

[7] *See* Ex. 2, *supra*.
[8] All modeling parameters can be found at http://www.epa.gov/airmarkt/progsregs/epa-ipm/BaseCasev410.html.
[9] *See* EPA's plans for this rule at http://water.epa.gov/scitech/wastetech/guide/steam_index.cfm

fired power plants will be constructed in the foreseeable future." 77 Fed. Reg. at 22,413, and the Energy Information Administration (EIA) is documenting increasing retirements of existing plants. In particular, the EIA's Annual Energy Outlook for 2012 forecasts no new unplanned coal capacity through 2020. RIA at 5-5. EIA's most recent Electric Power Monthly report confirms that this trend continues. Thus far this year, *none* of the 5,627 MW of new units to come online are coal-fired; instead, new capacity additions are largely in renewable power or natural gas. EIA, *Electric Power Monthly June 2012* at Table ES3.[10] Conversely, retirements to date have been predominantly coal-fired units. *See id.* at Table ES4. Utilities across the country have announced thousands of megawatts worth of coal retirements over the last few years.[11]

Industry-wide levelized cost figures compiled by independent analysts demonstrate why these retirements are occurring. The most recent (2011) edition of Lazard's Levelized Cost of Energy Analysis,[12] a widely-used reference, shows that energy efficiency, wind, and natural gas combined cycle levelized costs are already below those of coal, as the figure below demonstrates.



Under these circumstances, prudent operators are increasingly deciding not to impose additional costs on their ratepayers by running coal-fired units with costly new pollution technology. Instead, they are opting to retire older units and pursue cleaner, cheaper, energy options. Progress Energy could, and should, decide to follow the same course.

D. Recommended Commission Action

[10] Available at: http://205.254.135.7/electricity/monthly/pdf/epm.pdf.

[11] *See, e.g.*, Progress Energy Press Release, "Progress Energy Carolinas to retire coal power plant ahead of schedule" (Apr. 1, 2011) (recording the retirement of four North Carolina coal plants), available at https://www.progress-energy.com/company/media-room/news-archive/press-release.page?title=Progress+Energy+Carolinas+to+retire+coal+power+plant+ahead+of+schedule&pubdate=04-01-2011; FirstEnergy Press Release, "FirstEnergy, Citing Impact of Environmental Regulations, Will Retire Six Coal-Fired Power Plants" (Jan. 29, 2012) (announcing the retirement of six coal plants in Ohio), available at https://www.firstenergycorp.com/content/fecorp/newsroom/news_releases/firstenergy_citingimpactofenvironmentalregulationswillretiresixc.html; Environment News Service, "Dominion Virginia to Replace Coal Plants with Gas, Nuclear" (Sept. 7, 2011) (documenting retirement of two Virginia coal plants), available at http://www.ens-newswire.com/ens/sep2011/2011-09-07-091.html.

[12] Attached as Ex. 6.

Progress Energy has entirely failed to address these environmental compliance issues, and the impacts of retirements at Crystal River upon its system and upon ratepayers. The failure renders the draft plan "unsuitable" as a planning document. *See* F.S. §186.801. The Commission, "may suggest alternatives to the plan," *id.*, however, and may classify a plan as suitable upon the submission of "additional data," *see* F.A.C. § 25-22.071(5). We respectfully request that the PSC exercise its authority to ensure that Progress's plan provides adequate data to allow the PSC and the public to address these plant retirements.

Specifically, we submit that the Commission should seek the following information from Progress and require resubmission of a complete plan addressing these submissions:

1. The utility should provide an analysis of all environmental compliance obligations which it will experience at the Crystal River plant. For each requirement, the utility should cite the relevant rule, explain how it is likely to apply to the plant, the likely costs of compliance to the utility and to ratepayers, and the timeline on which compliance will be required. The utility should also document any steps it has taken to address these compliance obligations, and alternative steps it might take. For instance, if the utility anticipates that it will have to install a scrubber to comply with MATS, it should report to the Commission on scrubber installation and operation costs, whether it has contracted to purchase a scrubber and on what timeline, and what other options it has considered. *See* F.S. § 186.801 (requiring utilities to document "[p]ossible alternatives to the proposed plan").

2. The utility should provide a comparative analysis of compliance costs and the cost costs of replacing the plant's power through energy efficiency, demand response, power purchase agreements, new generation facilities, or other means. *See* F.S. §186.801 (requiring utilities to explain the impact of their plans on fuel diversity and on the need for electric power in their regions). In light of this analysis, the utility should indicate whether it intends to retire any facility, and on what timeline, and the relative costs of retirement versus those of other options. If retirement has not been selected but is being considered, the utility should indicate when the decision will be made.

3. For any facility where retirement is possible, the utility should discuss how it intends to address any reliability issues which may be caused by the retirement. The Commission should play an active role in this regard, as it must maintain reliability of the electric grid. *See* F.S. § 366.05(7)-(8) (authorizing the Commission to "require reports from all electric utilities to assure the development of adequate and reliable energy grids" and to order "installation and repair of necessary facilities" to address reliability issues"). The Commission has determined that "[r]eserve margins in Florida typically remain well above" relevant minimums through 2020, so system-wide resource adequacy problems are unlikely, but the Commission may still need to address localized reliability issues. If such problems appear to be present, the

Commission should work proactively and transparently with the Florida Reliability Coordinating Council to address them well in advance of any planned retirement.

We appreciate this careful consideration of Progress Energy's environmental compliance options, and any resulting plant retirements, and remind the Commission that such thorough analysis is required to ensure that the Ten-Year Plan complies with legal requirements. We request that the Commission share the results of its inquiry with us and with the public, and request formal notice of the Commission's next steps.

Please contact the undersigned with any concerns or questions.

Sincerely,
s/ Craig Holt Segall
Craig Holt Segall
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II. Outside Persons Who Wish to Address the Commission at Internal Affairs

OUTSIDE PERSONS WHO WISH
TO ADDRESS THE COMMISSION AT

INTERNAL AFFAIRS
October 24, 2013

Speaker	**Representing**	**Item #**
Susan Masterton	CenturyLink	1
Greg Follensbee	AT&T	1
De O'Roarke	Verizon	1
J.R. Kelly	OPC	1

III. Supplemental Materials for Internal Affairs

NOTE: The following material pertains to Item 2 of this agenda.

State of Florida

Public Service Commission

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

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

DATE:	October 23, 2013
TO:	Braulio L. Baez, Executive Director
FROM:	Thomas E. Ballinger, Director, Division of Engineering
RE:	Proposed revisions to Review of 2013 Ten-Year Site Plans. This item is scheduled for discussion as Item # 2 on the 10/24 Internal Affairs conference

Yesterday afternoon, I was made aware of some typographical errors in the above mentioned report. I have attached a document showing the suggested corrections in type and strike format. Please let me know if you approve of this request.

approved
10/23/13

Attachment

Cc: w/attachment
Lisa Harvey

Parties/Staff Handout
Internal Affairs Agenda
on 10/24/13
Item No. 2

Proposed Modifications to Review of 2013 TYSP

Page 3, second paragraph

Traditional Generation

Natural gas is anticipated to remain the dominant fuel over the planning horizon, with usage in 2012 increasing to 64.8 percent of the state's net energy for load (NEL), up from 57.7 percent of NEL in 2011. Figure 2 below illustrates the increasing use of natural gas as a generating fuel for the electricity production during the last ten years, and the projected use during the next decade. State-wide, natural gas usage is expected to decline slightly, on a percentage basis, from its current peak, to 58.8 percent in 2022. This is due to projected increases in nuclear generation, and a limited impact of new environmental compliance requirements.

Page 16, second full paragraph

The last annual demand and energy goal-setting proceeding was completed in December of 2009, providing annual goals for the period of 2010 through ~~2020~~ 2019. To meet the requirement to set goals at least once every five years, the Commission must establish annual goals for the 2015 through ~~2025~~ 2024 period by the end of 2014. The Commission already established dockets for each of the seven FEECA Utilities in July 2013, with hearing dates set for July 2014, and a final decision by the Commission expected by October 2014.

Page 17, second full paragraph

For each category the impacts of conservation (including some self-service generators), and for seasonal peak demand, load management programs, and interruptible/curtailable load is shown. The total demand or total energy for load represents what otherwise would be served if not for the impact of demand response and conservation programs. The net firm demand ~~or net energy for load represents the anticipated final demand or energy value, and~~ is used as a planning number for the calculation of generating reserves.

Page 23, third full paragraph

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. Based on actual data collected from the three facilities, the maximum output does not appear to be coincident with the system's peak demand.

Page 30, revised Table 12

Utility	Generating Unit Name	Generator Type	Summer Capacity (MW)	Planned Retirement Date	Notes
Nuclear Units					
DEF**	Crystal River 3	Nuclear Steam	850	01/2013	
Oil-Fired Units					
FPL	Port Everglades 3 & 4	Oil Steam	761	01/2013	Modernization
FPL	Turkey Point 1 & 2	Oil Steam	788	01/2013	Synch. Condenser
DEF	Suwannee River 1 - 3	Oil Steam	129	06/2018	
DEF	Various	Oil Turbine	56	04/2016	
Coal-Fired Units					
DEF	Crystal River 1 & 2	Coal Steam	869	04/2016	EPA Rules Related
GPC	Scholz 1 & 2	Coal Steam	92	04/2015	EPA Rules Related
Gas-Fired Units					
FPL	Municipal Plant 2 & 5	Gas CC	44	01/2017	
FPL	Municipal Plant 1, 3, 4	Gas Steam	94	01/2014	
DEF	Various	Gas Turbine	129	06/2016	
GPC	Pea Ridge 1-3	Gas Turbine	12	12/2018	
GRU	Various	Gas Steam	98	10/2015*	
GRU	JR Kelly GT01-03	Gas Turbine	42	02/2018*	
TAL	Various	Gas Turbine	56	03/2015*	
TAL	Various	Gas Steam	124	12/2013*	
Total			**4,144**		

*Planned Retirement Date is for earliest unit retirement. Other units may retire later than indicated here
** Multiple Joint Owners for Crystal River 3. Primary owner listed here.

Source: 2013 TYSPs, 2013 FRCC Regional Load & Resource Plan

Page 31, last paragraph

Role of Demand Side Management in Reserve Margin

It should be noted that the reserve margin figures above are calculated using the net firm system demand for the diagonal shaded value, which assumes full use of interruptible load and load management devices to reduce peak demand, while the ~~total system demand,~~ reserve margin which only includes generation and conservation~~,~~ is the solid value. Participation in interruptible rates and load management programs are voluntary, for which incentives are provided in the form of lower rates or credits paid to the participant. As shown in Figure 11 above, the state as a whole has sufficient generation capacity planned throughout a majority of the period to meet the minimum reserve margin of 15 percent without relying on demand response. As noted previously, these customers have not typically been activated during periods of peak demand.

Page 32, first full paragraph

New Generation Resources

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 ~~traditional~~ additional generating capacity still exists. While reductions in demand have been significant, the total demand for electricity and the per-capita consumption 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.

Page 37, top of page

flexibility in their generation fuel source mix. Although the Commission has cited the growing lack of fuel diversity within the State of Florida as a major strategic concern for the past several years, natural gas is anticipated to remain the dominant fuel over the planning horizon. Excluding renewables and one nuclear unit, all new generation facilities planned within the State of Florida over the ten-year period are natural gas-fired units.

Page 38, revised Table 15

Utility	Generating Unit Name	Summer Capacity (MW)	Certification Dates		In-Service Date
			Need Approved (Commission)	PPSA Certified	
Combined Cycle Units					
FPL	Cape Canaveral	1,210	09/2008	10/2009	06/2013
FPL	Riviera Beach	~~1,277~~1,212	09/2008	11/2009	06/2014
FPL	Port Everglades	~~1,212~~1,277	04/2012	03/2013	06/2016
DEF	Unnamed CC 1	1,189	*	*	06/2018
DEF	Unnamed CC 2	1,189	*	*	06/2020
TECO	Polk 2-5 CC Conversion	459	12/2012	*	01/2017
SEC	Unnamed CC 1	192	*	*	12/2020
SEC	Unnamed CC 2	192	*	*	12/2020
Combustion Turbine Units					
SEC	Unnamed CT 1	198	**	**	12/2019
TECO	Future CT	190	**	**	05/2020
TAL	Hopkins 5	46	**	**	05/2020
SEC	Unnamed CT 2 & 3	396	**	**	12/2020
SEC	Unnamed CT 4 - 7	792	**	**	12/2021
DEF	Unnamed CT	187	**	**	06/2022
Total Natural Gas Additions		**8,683**			

* These units have not yet received a Determination of Need and/or a PPSA Certification.
** These units are not regulated under the PPSA, and do not require a Determination of Need.

Source: TYSP Utilities Data Response

Page 43, revised Table 18

Generating Unit Name	Generator Type	Summer Capacity (MW)	In-Service Date	PPSA
Natural Gas Units				
Cape Canaveral Energy Center	Combined Cycle	1,210	06/2013	Approved
Riviera Beach Energy Center	Combined Cycle	~~1,277~~1,212	06/2014	Approved
Port Everglades Energy Center	Combined Cycle	~~1,212~~1,277	06/2016	Approved
Nuclear Units				
Turkey Point Unit 4 Uprate	Steam Turbine	120*	03/2013	Approved
Turkey Point Unit 6	Steam Turbine	1,100	06/2022	Pending
~~Turkey Point Unit 7~~	~~Steam Turbine~~	~~1,100~~	~~12/2023~~	~~Pending~~

*This capacity represents the uprate only, not the full capacity of the generating unit
Source: 2013 TYSP Schedule 8

Page 44, Source Reference for Figure 20

(Note, this change applies to other individual figures on pages 48, 52, 56, 60, 64, 68, 72, 76, 80, and 84)

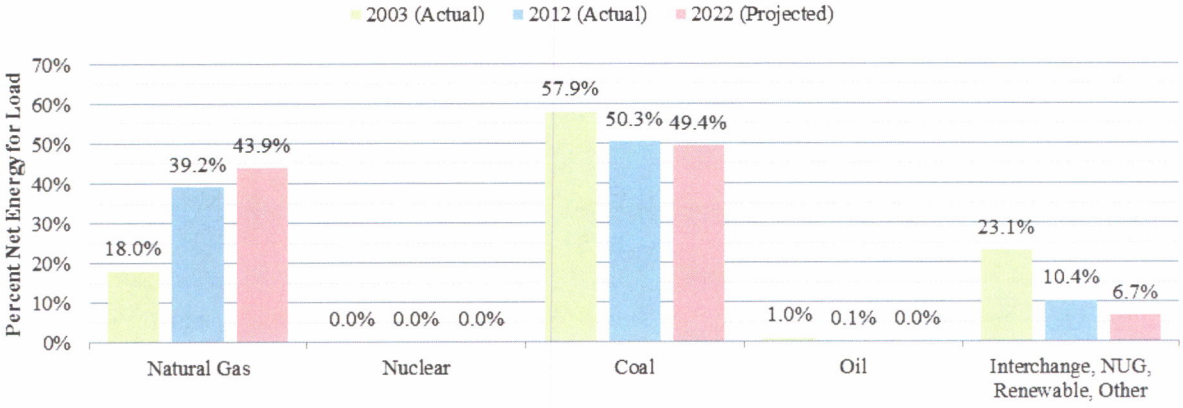
Source: Based on 2013 TYSP Schedules 3 & 7

Page 51, top of page

Fuel Diversity

Figure 1 shows TECO's historic fuel mix for 2003 and 2012, and the projected fuel mix for 2022. TECO's primary generation fuel is coal, one of only two utilities in the state that relied upon the solid fuel over natural gas in 2012, with 50.3 percent of system energy generated by coal. Coal usage has declined however, primarily with the increase of natural gas, which is the next highest fuel for TECO's system energy. Natural gas has risen to 39.2 percent of system energy in 2012, up from only ~~2.4~~ 18.0 percent in 2003. Coal is anticipated to remain the main system fuel throughout the planning period, making up 49.4 percent in 2022, although natural gas is projected to replace purchased power and increase its share of system energy to 43.9 percent in 2022.

Figure 1: TECO - Fuel Diversity (History & Forecast)



Source: 2013 TYSP Schedule 6

Page 52, first paragraph

Reserve Margin

TECO maintains a minimum 20 percent reserve margin for planning purposes based on a stipulation approved by the Commission. Figure 30 displays the forecast planning reserve margin for TECO through the planning period for both seasons including the effects of projected conservation activities. The impact of demand response programs on reserve margin is also included. As shown in the figure, TECO is generally a winter-peaking utility, during certain periods summer peak demand can be of greater concern. TECO also maintains a minimum supply-side contribution to its reserve margin, set at 7 percent, which it exceeds ~~by more than 100 percent~~ in all years of the planning period.

Page 56, first paragraph

Reserve Margin

GPC is not within the FRCC region, and therefore not subject to its minimum reserve margin requirements. GPC operates within SERC, and as part of the Southern Power Pool has a planning reserve margin of 15 percent after 2015. Figure 35 displays the forecasted planning reserve margin for GPC through the planning period for both seasons, including the effects of projected conservation activities. As shown in the figure, GPC ~~is a winter peaking utility for most years and~~ has sufficient reserve margin to meet projected customer demands for both seasons throughout the planning period

Page 84, first paragraph

Reserve Margin

TAL is within the FRCC region and is required to meet a 15 percent reserve margin requirement. However, TAL has adopted an ~~18~~ 17 percent planning reserve margin requirement. Figure 70 displays the forecast planning reserve margin for TAL through the planning period for both seasons including the effects of projected conservation activities. The impact of the utility's demand response programs, which are focused on summer demand only, is also included in the summer reserve margin. As shown in the figure, TAL is a summer peaking utility and has sufficient reserve margin to meet projected customer demands throughout the period when including demand response.

IV. Transcript

BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

PROCEEDINGS:	INTERNAL AFFAIRS
COMMISSIONERS PARTICIPATING:	CHAIRMAN RONALD A. BRISÉ COMMISSIONER LISA POLAK EDGAR COMMISSIONER ART GRAHAM COMMISSIONER EDUARDO E. BALBIS COMMISSIONER JULIE I. BROWN
DATE:	Thursday, October 24, 2013
TIME:	Commenced at 2:02 p.m. Concluded at 2:29 p.m.
PLACE:	Gerald L. Gunter Building Room 105 2540 Shumard Oak Boulevard Tallahassee, Florida
REPORTED BY:	JANE FAUROT, RPR Official FPSC Reporter (850) 413-6732

P R O C E E D I N G S

CHAIRMAN BRISÉ: Good afternoon. (Echo.) I can hear myself. It is Thursday, the 24th of October, and we will call to order our Internal Affairs meeting for today. And we will take up Item 1.

MR. CASEY: Good afternoon, Commissioners. Bob Casey on behalf of staff.

Item Number 1 addresses staff's draft petition to the FCC requesting a permanent waiver of a requirement contained in four new FCC rules to provide hard-copy Lifeline certification forms to eligible telecommunications carriers. The United States Telecom Association filed for and received three consecutive temporary waivers of this requirement on behalf of states which included Florida through February 1st, 2014.

CHAIRMAN BRISÉ: Bob, just wait one second. Can you all hear?

MR. KELLY: We can hear him, but it's not on the speaker.

CHAIRMAN BRISÉ: Okay.

(Off-the-record discussion.)

CHAIRMAN BRISÉ: Go ahead.

MR. CASEY: The current waiver order states that no later than November 1st, 2013, each state still

subject to this waiver must file a status update with the FCC. And if a state believes that it will be unable to come into compliance and seeks a permanent waiver from the rules, it must provide in its request for permanent relief an explanation for why such relief is appropriate.

The Florida Lifeline, the electronic coordinated enrollment process does not have the capability of printing out a hard-copy Lifeline application, but does allow eligible telecommunications carriers to adhere to the requirements of the Lifeline reform order without the need to require or maintain hard-copy Lifeline certification applications.

Staff believes the FCC requirement to provide hard-copy certifications is unnecessary, not cost-effective, and would penalize Florida for having an efficient, verifiable, and streamlined Lifeline electronic coordinated enrollment process. Staff is seeking Commission approval to file the status update and permanent waiver request by November 1.

Staff is available for questions.

CHAIRMAN BRISÉ: Thank you very much.

Before we get into questions, I know that there are several speakers that are interested in this matter, so I'll give them an opportunity to address us,

if they so wish.

Ms. Khazraee from CenturyLink --

MS. MASTERSON: I'm sorry.

CHAIRMAN BRISÉ: Yes, ma'am.

MS. MASTERSON: Did you want me to go ahead or --

CHAIRMAN BRISÉ: You can go ahead.

MS. MASTERTON: This is Susan Masterton, Counsel for CenturyLink, and we are just here in support of the staff's waiver proposal.

CHAIRMAN BRISÉ: Okay, thank you.

Greg Follensbee from AT&T.

MR. FOLLENSBEE: Yes. Greg Follensbee with AT&T. If I was at the Legislature I would say waive and support, but, yes -- (audience laughter) -- we are in support of the permanent waiver. We have gone through the trials and tribulations of having to deal with what happens when a temporary waiver ends. It is a catch-up that we prefer to not to have to do in the future.

CHAIRMAN BRISÉ: Thank you. We have Dee O'Roark from Verizon.

MR. O'ROARK: Thank you, Mr. Chairman. Verizon also supports the petition.

CHAIRMAN BRISÉ: All right. Thank you.

We have Lisa Steffens from OPC.

MR. KELLY: We support.

CHAIRMAN BRISÉ: All right. Thank you.

All right. Commissioners, any comments or questions?

COMMISSIONER BROWN: I have a question. What is the likelihood of a permanent waiver? I'm sorry, can you hear me in the back? I'm trying to speak loud. What's the likelihood of having a permanent waiver?

MR. CASEY: I would be hesitant to predict what the FCC would do. But in phone conversations with our staff, they are treating this like an administrative thing. Because they know the Florida process better than any other state, they said just file a permanent waiver and we'll take care of it.

COMMISSIONER BROWN: And you have been in contact with the FCC continuously so --

MR. CASEY: For a year and a half.

COMMISSIONER BROWN: Can I make a suggestion --

MR. CASEY: Yes, Commissioner.

COMMISSIONER BROWN: -- on the proposed recommendation order? On Page 6 --

MR. CASEY: Okay.

COMMISSIONER BROWN: -- it's the introduction and summary. And I think right at the top of that

paragraph, that's not in full, but it's right at the top where it says the Florida Lifeline Electronic Coordinated Enrollment Process does not have the capability of printing out a hard copy of the Lifeline application as required. I think it would be helpful -- you have some great language throughout towards the latter part of the recommendation, if you summarize why so they have that in the intro. In the summary it just says that we don't have the capabilities, but if you could provide -- on Page 17 it says, three-quarters of the way down it says it would be extremely difficult, if not impossible to isolate -- that area, that paragraph there, you have got some good language there, maybe you want to incorporate there, that summarizes.

MR. CASEY: Sure, I'd be glad to.

COMMISSIONER BROWN: Thanks for your work on it.

CHAIRMAN BRISÉ: Okay. Anything else, Commissioners, on this item? Okay.

If not, we are ready to entertain a motion.

COMMISSIONER EDGAR: I think that's a good suggestion. Thank you, Commissioner Brown.

I think this is all good, good staff work. And I move that we approve it, and ask our staff to do whatever they need to follow through.

COMMISSIONER GRAHAM: Second.

CHAIRMAN BRISÉ: Okay. It has been moved and seconded.

Further comments? Seeing none, all in favor say aye.

(Vote taken.)

CHAIRMAN BRISÉ: Thank you very much. And, staff, thank you very much for your work on this.

MR. CASEY: Thank you, Commissioners.

* * * * * * *

CHAIRMAN BRISÉ: Moving on to Item Number 2, which is review of the Ten-Year Site Plan for 2013.

MR. ELLIS: Phillip Ellis with Commission staff. Item 2 is the draft review of the 2013 Ten-Year Site Plans for the Florida electric utilities. Overall, the report is similar in format and content to last year's review. We broke it into three sections: A statewide review; a utility-specific review; and then a collection of comments we've received. We also have an oral modification to several components I have just handed out. Would you like me to go over each item?

CHAIRMAN BRISÉ: No. If we have questions about them, we'll address them.

MR. ELLIS: Overall they are just minor corrections and clarifications. For the statewide

review, staff noticed three trends, a decline in retail energy sales. As of last year compared to the previous ten years, sales have only increased .6 percent from 2003 levels, but a total customer growth of 11 percent during that period.

A second trend we noticed was EPA rules having an impact. Overall, these rules are still in the proposed stage or being addressed in courts, but overall their impact will be to increase the cost of coal-fired generation as well as increase the likelihood of retirements, which leads to the third trend, which is a higher natural gas usage. We hit a record of about 64 percent natural gas being fuel for electricity last year. Partly that was due to the uprates of some of FPL's units and those units being off-line during that period in time. We expect it to come back down to approximately 60 percent, but stay at that level for most of the rest of the period.

For the utility-specific section, the main one we looked at was Duke, which is going to be relying heavily on purchased power agreements, especially in 2016 and 2017, due to some coal retirements potentially related to EPA rules. It looks to be sufficient capacity within the state for reserve margin purposes, and the company is already pursuing RFPs for capacity

within and outside of the state.

For comments, we had, I believe, one group suggest FPL's Ten-Year Site Plan was unsuitable, it was Treasure Coast Regional Planning Council. Their concerns were associated with FPL's high dependence on natural gas and a lack of renewables and energy efficiency.

We also had comments from Sierra Club, Earth Justice, and SACE. We also have additional comments that were not included in the initial draft, about 160 pages, and we would ask for authority to add those comments to Appendix A for forwarding to the Department of Environmental Protection and Department of Agriculture.

CHAIRMAN BRISÉ: All right. Thank you very much. Before we go to questions, I think we have Diana Schenk from the Sierra Club that wants to speak.

Okay, she's not here.

So, Commissioners, the floor is open for questions or comments.

COMMISSIONER BALBIS: May I comment?

CHAIRMAN BRISÉ: Sure. Commissioner Balbis.

COMMISSIONER BALBIS: Thank you.

Page 2, Figure 1. And we talked about this in our briefing, but you have an interesting graphic that

shows that the gap is spreading between the number of customers and retail energy sales. What do you attribute that to?

MR. ELLIS: It's a combination of factors. It's energy efficiency partly. The decline in energy sales is probably associated with the recession, but you have increased appliance standards, increased building codes, a variety of conservation efforts, and things of that manner are generally decreasing the per capita usage, so that is probably one of the major associations there.

COMMISSIONER BALBIS: Okay. And then as far as the number of customers, I mean, that has increased, and how does that reflect on the individual customer classes from residential, commercial, and industrial?

MR. ELLIS: Compared to ten years ago, I believe industrial is still slightly negative and will probably remain negative throughout the period compared to 2003. I believe residential and commercial have recovered from their decline. Overall, those rates are expected to increase throughout the period, though.

COMMISSIONER BALBIS: Okay. And as compared to last year, do you have data on that?

MR. ELLIS: I believe growth was approximately .8 percent across all groups. I don't have that broken

down by individual group, though.

COMMISSIONER BALBIS: Okay. That's all I have.

CHAIRMAN BRISÉ: All right. Any further questions or comments?

Commissioner Brown.

COMMISSIONER BROWN: I have a question on Page 31, the reserve margin. Figure 11, the summer, the summer reserve margin. In 2020 and 2021, without the demand response it goes beneath the 15 percent. Can you explain how it dips and how it fluctuates over that ten-year period, highlighting those two years?

MR. ELLIS: Overall, during this entire period all of them are assuming the addition of incremental conservation which goes into the baseline which effects both the without demand response portion and with demand response portion. As customer load increases, assuming no change in generation capacity, reserve margin will decrease. This includes all the units they are anticipating adding in the Ten-Year Site Plans, so the decline further on is mostly due to the final impacts of any and all retirements of units, as well as additions as they go through. For those two years, I can't recall any specific reason why that would drop as low, compared to the others. I do know in 2022 the main unit being

added that year is Turkey Point 6.

COMMISSIONER BROWN: And this includes the 11 utilities that filed their Ten-Year Site Plans?

MR. ELLIS: This is actually the State of Florida as a whole, so it's all Florida utilities, including not just the Ten-Year Site Plan utilities, but others that are included from the FRCC data.

COMMISSIONER BROWN: Okay, thank you. And then I want to talk about the electric vehicles section. You have a summary section, I think, on Page 13. Go back. But I just want to look at that for a second, how they measured growth in this chart. It goes from the current -- in 2013, the current is .025, and then in 2022 it jumps to 2 percent, and I'm just curious how you measured that growth in the chart, those estimates.

MR. ELLIS: With the electric vehicles, I believe it was just on various forecasts of -- I'm trying to recall specifically. Could you ask the question? I think I got myself confused; I apologize.

COMMISSIONER BROWN: Well, the estimated number of plug-ins here, the plug-in EVs by service territory, I was curious how they measured it in terms of the estimated growth by this chart, acknowledging the fact that currently in 2013 the percentage is .025 percent, and then it jumps to 2 percent. And I

know that these are estimates, but I'm curious how they actually measured it.

MR. ELLIS: I think each individual utility had a different method of calculating. We asked the individual utilities what their estimate within their service territory would be. They relied upon a variety of different industry reports, and they usually took a statewide or national model and then looked at their portion of that to determine the estimate of growth. Some of them were more optimistic than others, and some of the scenarios were more optimistic than others.

COMMISSIONER BROWN: But even that jump to 2 percent, that doesn't have a tremendous impact on the overall grid.

MR. ELLIS: No. There's a relatively small impact from electric vehicles, but it is something that we noted and we are keeping track of. It probably will have a greater impact on the distribution system. If there are several electric vehicles added to a single street, it could have distribution impacts there, but I don't believe we're looking at any major impacts on the grid as a whole at this point.

COMMISSIONER BROWN: Thank you. Thanks for your work on it.

CHAIRMAN BRISÉ: Any further questions?

Commissioner Balbis.

COMMISSIONER BALBIS: Yes, a follow-up on Commissioner Brown's comment on Figure 11. How do the utilities forecast the additional demand-side management programs as we are going through the goal-setting process next year?

MR. ELLIS: At this point, there are currently FEECA goals established through 2019. And for the last few years for most of the utilities, I believe, they just assumed a continuation of the existing plans. Not all of the utilities that are under this are under FEECA. We have several municipal utilities that we do not cover, so they have their own energy efficiency demand response plans. I know some of them have -- I believe the City of Tallahassee has a summer-only one, but not a winter demand response program. Things of that nature that aren't covered under FEECA.

COMMISSIONER BALBIS: Okay. And the last question. On Table 12 on Page 30, and I don't know if I missed this last year, but does Mr. Kelly have a plant named after him, the J.R. Kelly plant?

MR. KELLY: It ain't me. (Audience laughter.) It's definitely not a -- (inaudible; laughter)

MR. ELLIS: I believe that is actually a historic figure associated with Gainesville. I will

admit to not knowing.

COMMISSIONER BALBIS: Okay. Just curious. That's all I had.

CHAIRMAN BRISÉ: Any further questions or comments?

All right. If not, we are in an appropriate posture to entertain a motion.

COMMISSIONER BROWN: I move that we forward this along to DEP and consider these plans as suitable.

COMMISSIONER GRAHAM: Second.

CHAIRMAN BRISÉ: Okay. It has been moved and seconded.

Any further discussion?

Seeing none, all in favor say aye.

(Vote taken.)

CHAIRMAN BRISÉ: Thank you very much.

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CHAIRMAN BRISÉ: Now we move to Item Number 3, which is our legislative update.

MS. PENNINGTON: Hi, everyone. I just have a couple of things. We had a couple of weeks off between committee meetings. The next set of committee meetings will begin the week of -- will be the week of November 4th. We really haven't heard yet what committees may be doing at that time.

I will tell you that the bills are starting to come in. One thing that, you know, we have seen a couple that were filed last year, the bills relating to fracturing have been filed again.

The only one I wanted to bring to your attention today, and we have -- a bill analysis request has been made of us, and that's Senate Bill 272 by Senator Simpson. It's a water and wastewater bill, and there are some similarities in that bill and the bill that Senator Hays filed last year.

Senator Simpson's bill seems to focus on two areas. The first one, which is not one of the study committee recommendations, and to my memory was not discussed, is that it would basically say that the rates of investor-owned water and wastewater utilities could not be higher than the rates of the government-owned municipal utility, if there is one located in the same county. It further, basically, says that the Commission must adjust those rates to no more than the municipal or government-owned water or wastewater utility back to the rates at the last rate hearing, and that the utility must refund all monies within 12 months. So that was not part of the recommendations of the study committee.

He does seem to have picked up the secondary water standard language that was part of the study

committee's recommendations that the Commission would take that into account using information from the Department of Environmental Regulation, water management districts, local governments, consumer complaints, et cetera, that they would use that same information to take -- into considering secondary water standards.

We have not finished our analysis yet. We may have a draft by tomorrow. And other than that, we are just responding to a lot of inquiries and requests and getting ready for committee meetings again.

CHAIRMAN BRISÉ: All right. Thank you.

Questions?

Commissioner Graham.

COMMISSIONER GRAHAM: Thank you, Mr. Chairman.

To Senator Simpson's bill, does it say anything or allude to anything as far as property tax and taxable value, because municipals don't have to pay property tax.

MS. PENNINGTON: It does not.

COMMISSIONER GRAHAM: Okay. And you said that staff is in the process of making sure that we put together an analysis?

MS. PENNINGTON: Yes, sir. We are working on an analysis now.

COMMISSIONER GRAHAM: Okay. That's all I

have.

CHAIRMAN BRISÉ: Commissioner Edgar.

COMMISSIONER EDGAR: Thank you. Just a calendar question.

MS. PENNINGTON: Yes, ma'am.

COMMISSIONER EDGAR: Katherine, if you know, and if not, that's okay. After the week of November 4th, how many more dates do they have scheduled for committee meetings prior to the end of the year?

MS. PENNINGTON: Let me not misspeak, and I will -- (inaudible; simultaneous conversation)

COMMISSIONER EDGAR: All of us.

MS. PENNINGTON: Yes, I will. Absolutely. I just don't want to misspeak. I think I could tell you, but I want to be sure.

The other thing, I did want to mention that Commissioner Brown did a great job in front of the Senate --

COMMISSIONER BROWN: No, I didn't.

MS. PENNINGTON: -- Communications, Energy, and Public Utilities Committee a couple of weeks ago.

COMMISSIONER BROWN: Thank you.

MS. PENNINGTON: I don't know what they are going to do with the information yet, but she did.

Yes, you did.

COMMISSIONER BROWN: I spoke faster than Speedy Gonzalez.

Thank you for your comments.

MS. PENNINGTON: And Senator Hays is still intending to file the bill that he filed last year regarding the recommendation for the water and wastewater study committee.

CHAIRMAN BRISÉ: All right. Anything else? Seeing none, thank you very much.

MS. PENNINGTON: Thank you.

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CHAIRMAN BRISÉ: Executive Director, Mr. Baez.

MR. BAEZ: Thank you, Mr. Chairman.

Two items. One brief one, just following up on the legislative update.

We are presenting our LBR and our Schedule AB Budget before the House Subcommittee on November 6th, I believe. It's a short time slot, and I believe it's in the afternoon for those of you that are interested, that's November 6th.

And my final item is a bittersweet one. As many of you may know, Ann Cole, our Commission Clerk, is leaving us. November 14th is her last day. And she has had probably in the, I think, relatively short time that she has been here -- she joined the Commission in '07, I

believe -- in that relatively short time that she has been here, she has had as much to do with this agency being dragged kicking and screaming into the late 20th Century as anyone in the building, and we are going to miss her. That's the bitter part.

The sweet part is that I'd like to propose her successor. Many of you know Carlotta Stauffer. She has been working with Ann these last several months, and actually had occasion to work with her for a long time at DOAH, which is where they both originated. So she has had good opportunity to learn Ann's brain and to understand her vision and her way of doing things and the good things that she has done for us, as well. And I'd like to nominate her or appoint her as the next Commission Clerk.

I can think of nobody better to take Ann's place, in part not just because of their experience together, but because, you know, Carlotta and I worked together for some time, and I think she has as much as anyone a terrific understanding both of the steps that Ann has put into place and the efforts that Ann has started us off on for the long-term. And, also, Carlotta understands as well as anyone what we're trying -- what executive management has been trying to do along those lines. So if there's anyone better to

bring all of these good things in for a landing and to a successful completion, I can't think of a one. So with your consent, I would like to name Carlotta Stauffer as our next Commission Clerk.

CHAIRMAN BRISÉ: Thank you.

Any comments, Commissioners?

COMMISSIONER EDGAR: Great choice.

CHAIRMAN BRISÉ: All right. I can't recall, does this require a vote?

MR. BAEZ: A simple nod would do.

COMMISSIONER BROWN: If I may?

CHAIRMAN BRISÉ: Sure.

COMMISSIONER BROWN: Yes, good choice.

MR. BAEZ: Thank you, Commissioner.

COMMISSIONER BROWN: Ann, we are going to miss you. You and I have gotten really close being so close together.

MS. COLE: I know.

COMMISSIONER BROWN: I'm going to miss you a lot.

And, Carlotta, I'm looking forward to working with you.

And best wishes to you in your future endeavors.

CHAIRMAN BRISÉ: All right.

MR. BAEZ: Thank you, Commissioners.

CHAIRMAN BRISÉ: Thank you. Excellent choice.

MR. BAEZ: I think so, too.

CHAIRMAN BRISÉ: And, Ann, we will stack up some more work before the 14th.

(Audience laughter.)

CHAIRMAN BRISÉ: But, in all seriousness, we definitely want to thank you for your service to the Commission.

MS. COLE: It's been fun.

CHAIRMAN BRISÉ: And, Carlotta, we expect great things from you going forward, as well.

MS. STAUFFER: Thank you.

CHAIRMAN BRISÉ: All right. Anything else, Mr. Baez?

MR. BAEZ: Nothing else today.

CHAIRMAN BRISÉ: Okay.

MR. BAEZ: Thank you, Chairman.

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CHAIRMAN BRISÉ: Other matters; anything on other matters today? Okay.

Seeing none. All right. With that, Commissioner Graham moves we rise.

(Internal Affairs meeting concluded at 2:29 p.m.)

STATE OF FLORIDA)

: CERTIFICATE OF REPORTER

COUNTY OF LEON)

I, JANE FAUROT, RPR, Chief, Hearing Reporter Services Section, FPSC Division of Commission Clerk, do hereby certify that the foregoing proceeding was heard at the time and place herein stated.

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.

I FURTHER CERTIFY that I am not a relative, employee, attorney or counsel of any of the parties, nor am I a relative or employee of any of the parties' attorney or counsel connected with the action, nor am I financially interested in the action.

DATED THIS 1st day of November, 2013.

JANE FAUROT, RPR
Official FPSC Hearings Reporter
(850) 413-6732