# I. Meeting Packet

# State of Florida
## Public Service Commission
### INTERNAL AFFAIRS AGENDA
Thursday – October 17, 2019
9:30 A.M.
Room 105 - Gerald L. Gunter Building

1. Draft 2019 Regulatory Plan (Attachment 1)
2. Review of 2019 Ten Year Site Plans (Attachment 2)
3. Legislative Update
4. General Counsel's Report
5. Executive Director's Report
6. Other Matters

BB/aml

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

**Attachment 1**

**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-

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**DATE:** October 8, 2019

**TO:** Braulio L. Baez, Executive Director

**FROM:** Kathryn G.W. Cowdery, Senior Attorney, Office of the General Counsel

**RE:** Florida Public Service Commission 2019 Regulatory Plan

**CRITICAL INFORMATION:** Please place on the October 17, 2019 Internal Affairs.

**Commission approval is sought**

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Pursuant to Section 120.74(1), Florida Statutes (F.S.), the Commission must prepare a regulatory plan by October 1 of each year. The plan must include a listing of each law enacted or amended during the previous 12 months that creates or modifies the duties or authority of the agency. The Commission must also include a listing of each statute which the Commission expects to implement by rulemaking before July 1, 2020, and must include any update to the 2018 Regulatory Plan. The plan must also include a certification verifying that the persons executing the certification have reviewed the plan and that the agency regularly reviews its rules to determine consistency with the agency's rulemaking authority and the laws implemented.

Section 120.74(2), F.S., requires that by October 1 of each year, the regulatory plan must be published on the Commission's website and electronically delivered to the Joint Administrative Procedures Committee (JAPC). Also by October 1, the Commission must publish a notice in the Florida Administrative Register (F.A.R.) that gives the date the 2019 Regulatory Plan was published on the Commission's website.

This item was originally scheduled for the September 5, 2019 Internal Affairs Agenda. However, the September 5, 2019 Internal Affairs was cancelled due to Hurricane Dorian. In order to comply with the statutory October 1, 2019 deadline, the 2019 Regulatory Plan has been submitted to JAPC under the Chairman's and General Counsel's signatures, posted on Commission's website, and noticed in the F.A.R. Nonetheless, staff is seeking Commission approval of the 2019 Regulatory Plan. If the Commission makes any changes to the plan, staff will provide JAPC with an amended regulatory plan, post the amended plan on the Commission's website, and publish an amended notice in the F.A.R.

The transmittal letter to JAPC contains the certification required by Section 120.74(1)(d), F.S. The list of laws that create or modify the Commission's duties or authority is attached to the certification letter as Attachment A. Attachment B to the certification letter is the Commission's list of laws that it expects to implement through rule adoption, amendment, or repeal before July 1, 2020. The Commission's report that it has no laws or updates to the 2018 Regulatory Plan is Attachment C to the certification letter.

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

**STATE OF FLORIDA**

ART GRAHAM
CHAIRMAN

Capital Circle Office Center
2540 Shumard Oak Boulevard
Tallahassee, FL 32399-0850
(850) 413-6040

# Public Service Commission

September 19, 2019

**DELIVERED VIA E-MAIL**

Mr. Kenneth J. Plante, Coordinator
Joint Administrative Procedures Committee
680 Pepper Building
111 W. Madison Street
Tallahassee, FL 32399-1400

**Re: Florida Public Service Commission's 2019 Regulatory Plan**

Dear Mr. Plante:

The Florida Public Service Commission (Commission) hereby files its 2019 Regulatory Plan pursuant to Section 120.74, Florida Statutes (F.S.).

Section 120.74(1)(a), F.S., requires a listing of each law enacted or amended during the previous 12 months which creates or modifies the duties or authority of the agency. For each law listed under paragraph (a), the plan must state whether rule adoption is required to implement the law, and if so, whether a notice of rule development has been published and the date by which the agency expects to publish the notice of proposed rule. The Commission's report of laws pursuant to Section 120.74(1)(a), F.S., is attached hereto as Attachment A.

Section 120.74(1)(b), F.S., states that the regulatory plan must also include a listing of each law not listed pursuant to Section 120.74(1)(a), F.S., that the agency expects to implement by rulemaking before the following July 1. For each law listed under paragraph (b), the plan must state whether the rulemaking is intended to simplify, clarify, increase efficiency, improve coordination with other agencies, reduce costs, or delete obsolete, unnecessary, or redundant rules. The Commission's report of laws pursuant to Section 120.74(1)(b), F.S., is attached hereto as Attachment B.

Section 120.74(1)(c), F.S., requires an identification and listing of laws that were previously identified in a prior year's regulatory plan as requiring rulemaking to implement, but for which a notice of proposed rule has not been published. The Commission has no laws or updates to report pursuant to Section 120.74 (1)(c), F.S. The Commission's report that it has no laws or updates to the 2018 Regulatory Plan is attached hereto as Attachment C.

Section 120.74(1)(d), F.S., requires the plan to include a certification. Pursuant to Section 120.74(1)(d), F.S., we hereby verify that we have reviewed the attached regulatory plan. We further verify that the Commission regularly reviews all of its rules and that the Commission's rules were most recently reviewed for the period July 2, 2015, through July 1, 2017, to determine if the rules remain consistent with the Commission's rulemaking authority and the laws implemented.

Sincerely,

Art Graham, Chairman
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, Florida 32399
(850) 413-6770

KEITH HETRICK
General Counsel
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, Florida 32399
(850) 413-6770

Enclosures

KGWC

FLORIDA PUBLIC SERVICE COMMISSION
2019 REGULATORY PLAN

ATTACHMENT A

LAWS CREATING OR MODIFYING DUTIES OR AUTHORITY- SECTION 120.74(1)(a), F.S.

| Laws | Rulemaking Necessary | Notice of Rule Development Published | Expected Date of Notice of Proposed Rule | Reason Why Rulemaking Is Not Necessary |
|---|---|---|---|---|
| Section 366.96, F.S., Public Utility Transmission and Distribution Storm Protection Plans | Yes, to implement Sections 366.96, F.S. | June 7, 2019 | October 31, 2019 | N/A |
| Section 119.071, F.S., General exemption from inspection or copying of public records, concerning victims of mass violence. | No | N/A | N/A | Applies to all agencies. The statute is specific as to public records exemption and is self executing |
| Section 256.16, F.S., Honor and Remember flag. Provides when and where state or local government units may display the flag and that rules may be adopted. | No | N/A | N/A | Applies to all agencies. The statute contains all necessary requirements applicable to the Public Service Commission and therefore rulemaking is not necessary |
| Section 286.0113, F.S., General exemptions from public meetings and public records requirements, concerning technology security information for government-owned or operated utilities | No | N/A | N/A | Applies to all agencies. The statute is specific as to public meetings and public records exemptions and is self executing |
| Chapter 908, F.S., Federal Immigration Enforcement | No | N/A | N/A | Applies to all agencies. The statute is specific as to agencies' duties and authority and is self-executing |

LAWS NOT CREATING OR MODIFYING DUTIES OR AUTHORITY- SECTION 120.74(1)(b), F.S.

| Laws | Intent of Rulemaking |
|---|---|
| Section 350.115, F.S. | To amend Rule 25-6.0141, F.A.C., Allowance for Funds Used During Construction, to remove outdated language<br><br>To amend Rule 25-6.0142, F.A.C., Uniform Retirement Units for Electric Utilities, to update the Code of Federal Regulations reference in subsection (1) and to include a link to the F.A.C. website for the List of Retirement Units that is incorporated by reference in subsection (3)<br><br>To consider whether to amend or repeal Rule 25-6.0143, F.A.C., Use of Accumulated Provision Acciounts 228.1, 228.2, and 228.4, to conform with new storm protection rules to be enacted pursuant to Section 366.96, F.S. (2019), Public Utility Transmission and Distribution Storm Protection Plans; to consider whether to amend this rule or adopt a new rule to include requirements addressing storm restoration cost processes<br><br>To amend Rule 25-6.082, F.A.C., Records and Reports, to clarify rule requirements<br><br>To consider whether to amend 25-7.0141, F.A.C., Allowance for Funds Used During Construction, to specify rule requirements |
| Section 350.121, F.S. | To amend paragraph (4)(a) of Rule 25-22.006, F.A.C., Confidential Information, to change the number of copies required to be filed to be consistent with current filing requirements |
| Section 364.03, F.S. | To amend Rule 25-14.013, F.A.C., Accounting for Deferred Income Taxes Under SFAS 109, to replace obsolete references to accounting standards with current standards; to update language in the rule to reference the Tax Cuts and Job Act of 2017; and to determine whether references to the IRS code and Revenue Procedure 88-12 need to be replaced with updated references<br><br>To amend Rule 25-14.014, F.A.C., Accounting for Asset Retirement Obligations Under SFAS 143, to replace the obsolete reference to SFAS 143 with the current standard |

LAWS NOT CREATING OR MODIFYING DUTIES OR AUTHORITY- SECTION 120.74(1)(b), F.S.

| Laws | Intent of Rulemaking |
|---|---|
| Section 364.035, F.S. | To amend Rule 25-14.013, F.A.C., Accounting for Deferred Income Taxes Under SFAS 109, to replace obsolete references to accounting standards with current standards; to update language in the rule to reference the Tax Cuts and Job Act of 2017; and to determine whether references to the IRS code and Revenue Procedure 88-12 need to be replaced with updated references<br><br>To amend Rule 25-14.014, F.A.C., Accounting for Asset Retirement Obligations Under SFAS 143, to replace the obsolete reference to SFAS 143 with the current standard |
| Section 364.17, F.S. | To amend Rule 25-14.012, F.A.C., Accounting for Postretirement Benefits Other Than Pensions, to replace obsolete references to Statement of Financial Accounting Standards 106 and 71 with current accounting standards |
| Section 364.183, F.S. | To amend paragraph (4)(a) of Rule 25-22.006, F.A.C., Confidential Information, to change the number of copies required to be filed to be consistent with current filing requirements |
| Section 364.33, F.S. | To amend Rule 25-4.511, F.A.C., Application for Original or Transfer of Pay Telephone Certificate, to remove language concerning transfers of Pay Telephone Certificates as unnecessary to implementation of the statute |
| Section 364.335, F.S. | To amend Rule 25-4.511, F.A.C., Application for Original or Transfer of Pay Telephone Certificate, to remove language concerning transfers of Pay Telephone Certificates as unnecessary to implementation of the statute |
| Section 364.3375, F.S. | To amend Rule 25-4.511, F.A.C., Application for Original or Transfer of Pay Telephone Certificate, to remove language concerning transfers of Pay Telephone Certificates as unnecessary to implementation of the statute |
| Section 366.03, F.S. | To amend Rule 25-6.033, F.A.C., Tariffs, to update the rule<br><br>To amend Rule 25-6.037, F.A.C., Extent of System Which Utility Shall Operate and Maintain, to update the rule and clarify standards |

LAWS NOT CREATING OR MODIFYING DUTIES OR AUTHORITY- SECTION 120.74(1)(b), F.S.

| Laws | Intent of Rulemaking |
|---|---|
| Section 366.03, F.S. (cont.) | To consider whether to amend or repeal Rule 25-6.044, F.A.C., Continuity of Service, to conform with new storm protection rules to be enacted pursuant to Section 366.96, F.S. (2019), Public Utility Transmission and Distribution Storm Protection Plans<br><br>To consider whether to amend or repeal Rule 25-6.0455, F.A.C., Annual Distribution Service Reliability Reports, to conform with new storm protection rules to be enacted pursuant to Section 366.96, F.S. (2019), Public Utility Transmission and Distribution Storm Protection Plans<br><br>To repeal Rule 25-6.047, F.A.C., Constant Current Standards, as obsolete<br><br>To consider whether to amend or repeal Rule 25-6.061, F.A.C., Relocation of Poles, to conform with new storm protection rules to be enacted pursuant to Section 366.96, F.S. (2019), Public Utility Transmission and Distribution Storm Protection Plans<br><br>To consider whether to amend or repeal Rule 25-6.064, F.A.C., Contribution-in-Aid-of-Construction for Installation of New or Upgraded Facilities, to conform with new storm protection rules to be enacted pursuant to Section 366.96, F.S. (2019), Public Utility Transmission and Distribution Storm Protection Plans<br><br>To consider whether Rule 25-6.074, F.A.C., Applicability, should be repealed as unnecessary or amended to delete unnecessary language and to clarify rule requirements<br><br>To amend Rule 25-6.075, F.A.C., Definitions, to clarify the rule by specifying the rules to which the definitions apply<br><br>To consider whether to amend Rule 25-6.076, F.A.C., Rights of Way and Easements, to conform with new storm protection rules to be enacted pursuant to Section 366.96, F.S. (2019), Public Utility Transmission and Distribution Storm Protection Plans<br><br>To consider whether to amend or repeal Rule 25-6.077, F.A.C., Installation of Underground Distribution Systems Within New Subdivisions, to conform with new storm protection rules to be enacted pursuant to Section 366.96, F.S. (2019), Public Utility Transmission and Distribution Storm Protection Plans |

LAWS NOT CREATING OR MODIFYING DUTIES OR AUTHORITY- SECTION 120.74(1)(b), F.S.

| Laws | Intent of Rulemaking |
|---|---|
| Section 366.03, F.S. (cont.) | To consider whether to amend or repeal Rule 25-6.078, F.A.C., Schedule of Charges, Installation of Underground Distribution Systems Within New Subdivisions, to conform with new storm protection rules to be enacted pursuant to Section 366.96, F.S. (2019), Public Utility Transmission and Distribution Storm Protection Plans<br><br>To consider whether to amend Rule 25-6.080, F.A.C., Advances by Application, F.A.C., to conform with new storm protection rules to be enacted pursuant to Section 366.96, F.S. (2019), Public Utility Transmission and Distribution Storm Protection Plans<br><br>To consider whether to amend or repeal Rule 25-6.081, F.A.C., Construction Practices, to delete unnecessary language and/or to conform with new storm protection rules to be enacted pursuant to Section 366.96, F.S. (2019), Public Utility Transmission and Distribution Storm Protection Plans<br><br>To amend Rule 25-6.082, F.A.C., Records and Reports, to clarify the rule requirements<br><br>To amend Rule 25-6.104, F.A.C., Unauthorized Use of Energy, to clarify the rule requirements<br><br>To consider whether to amend or repeal Rule 25-6.115, F.A.C., Facility Charges for Conversion of Existing Overhead Investor-owned Distribution Facilities, to conform with new storm protection rules to be enacted pursuant to Section 366.96, F.S. (2019), Public Utility Transmission and Distribution Storm Protection Plans |
| Section 366.04, F.S. | To amend Rule 25-6.0141, F.A.C., Allowance for Funds Used During Construction, to remove outdated language.<br><br>To consider whether to amend or repeal Rule 25-6.0143, F.A.C., Use of Accumulated Provision Accounts 228.1, 228.2, and 228.4, to conform with new storm protection rules to be enacted pursuant to Section 366.96, F.S. (2019), Public Utility Transmission and Distribution Storm Protection Plans; to consider whether to amend this rule or adopt a new rule to include requirements addressing storm restoration cost processes<br><br>To consider whether to amend or repeal Rule 25-6.034, F.A.C., Standard of Construction, to conform with new storm protection rules to be enacted pursuant to Section 366.96, F.S. (2019), Public Utility Transmission and Distribution Storm Protection Plans |

LAWS NOT CREATING OR MODIFYING DUTIES OR AUTHORITY- SECTION 120.74(1)(b), F.S.

| Laws | Intent of Rulemaking |
|---|---|
| Section 366.04, F.S. (cont.) | To consider whether to amend or repeal Rule 25-6.0341, F.A.C., Location of the Uility's Electric Distribution Facilities, to conform with new storm protection rules to be enacted pursuant to Section 366.96, F.S. (2019), Public Utility Transmission and Distribution Storm Protection Plans<br><br>To consider whether to amend or repeal Rule 25-6.0342, F.A.C., Electric Infrastructure Storm Hardening, to conform with new storm protection rules to be enacted pursuant to Section 366.96, F.S. (2019), Public Utility Transmission and Distribution Storm Protection Plans<br><br>To consider whether to amend or repeal Rule 25-6.0343, F.A.C., Municipal Electric Utility and Rural Electric Cooperative Reporting Requirements, to conform with new storm protection rules to be enacted pursuant to Section 366.96, F.S. (2019), Public Utility Transmission and Distribution Storm Protection Plans<br><br>To consider whether to amend or repeal Rule 25-6.0345, F.A.C., Safety Standards for Construction of New Transmission and Distribution Facilities, to conform with new storm protection rules to be enacted pursuant to Section 366.96, F.S. (2019), Public Utility Transmission and Distribution Storm Protection Plans<br><br>To amend Rule 25-6.036, F.A.C., Inspection of Plant, to clarify rule standards<br><br>To amend Rule 25-6.037, F.A.C., Extent of System Which Utility Shall Operate and Maintain, to update the rule and clarify standards<br><br>To consider whether to amend or repeal Rule 25-6.044, F.A.C., Continuity of Service, to conform with new storm protection rules to be enacted pursuant to Section 366.96, F.S. (2019), Public Utility Transmission and Distribution Storm Protection Plans<br><br>To amend Rule 25-6.0440, F.A.C., Territorial Agreements for Electric Utilities, to clarify rule standards<br><br>To amend Rule 25-6.0441, F.A.C., Territorial Disputes for Electric Utilities, to clarify rule standards |

LAWS NOT CREATING OR MODIFYING DUTIES OR AUTHORITY- SECTION 120.74(1)(b), F.S.

| Laws | Intent of Rulemaking |
|---|---|
| Section 366.04, F.S. (cont.) | To consider whether to amend or repeal Rule 25-6.0455, F.A.C., Annual Distribution Service Reliability Reports, to conform with new storm protection rules to be enacted pursuant to Section 366.96, F.S. (2019), Public Utility Transmission and Distribution Storm Protection Plans<br><br>To repeal Rule 25-6.047, F.A.C., Constant Current Standards, as obsolete<br><br>To amend Rule 25-6.075, F.A.C., Definitions, to clarify the rule by specifying the rules to which the definitions apply<br><br>To consider whether to amend or repeal Rule 25-6.077, F.A.C., Installation of Underground Distribution Systems Within New Subdivisions, to conform with new storm protection rules to be enacted pursuant to Section 366.96, F.S. (2019), Public Utility Transmission and Distribution Storm Protection Plans<br><br>To consider whether to amend or repeal Rule 25-6.078, F.A.C., Schedule of Charges, Installation of Underground Distribution Systems Within New Subdivisions, to to conform with new storm protection rules to be enacted pursuant to Section 366.96, F.S. (2019), Public Utility Transmission and Distribution Storm Protection Plans<br><br>To amend Rule 25-6.082, F.A.C., Records and Reports, to clarify rule requirements<br><br>To consider whether to amend or repeal Rule 25-6.115, F.A.C., Facility Charges for Conversion of Existing Overhead Investor-owned Distribution Facilities, to conform with new storm protection rules to be enacted pursuant to Section 366.96, F.S. (2019), Public Utility Transmission and Distribution Storm Protection Plans<br><br>To amend Rule 25-14.012, F.A.C., Accounting for Postretirement Benefits Other Than Pensions, to replace obsolete references to Statement of Financial Accounting Standards 106 and 71 with current accounting standards |
| Section 366.041, F.S. | To amend Rule 25-6.0142, F.A.C., Uniform Retirement Units for Electric Utilities, to update the Code of Federal Regulations reference in subsection (1) and to include a link to the F.A.C. website for the List of Retirement Units that is incorporated by reference in subsection (3)<br><br>To amend Rule 25-6.075, F.A.C., Definitions, to clarify the rule by specifying the rules to which the definitions apply |

LAWS NOT CREATING OR MODIFYING DUTIES OR AUTHORITY- SECTION 120.74(1)(b), F.S.

| Laws | Intent of Rulemaking |
|---|---|
| Section 366.041, F.S. (cont.) | To consider whether to amend Rule 25-6.076, F.A.C., Rights of Way and Easements, to conform with new storm protection rules to be enacted pursuant to Section 366.96, F.S. (2019), Public Utility Transmission and Distribution Storm Protection Plans<br><br>To consider whether to amend or repeal Rule 25-6.077, F.A.C., Installation of Underground Distribution Systems Within New Subdivisions, to conform with new storm protection rules to be enacted pursuant to Section 366.96, F.S. (2019), Public Utility Transmission and Distribution Storm Protection Plans<br><br>To consider whether to amend Rule 25-6.080, F.A.C., Advances by Application, to to conform with new storm protection rules to be enacted pursuant to Section 366.96, F.S. (2019), Public Utility Transmission and Distribution Storm Protection Plans |
| Section 366.05 F.S. | To consider whether to amend or repeal Rule 25-6.034, F.A.C., Standard of Construction, to conform with new storm protection rules to be enacted pursuant to Section 366.96, F.S. (2019), Public Utility Transmission and Distribution Storm Protection Plans<br><br>To consider whether to amend or repeal Rule 25-6.0341, F.A.C., Location of the Uility's Electric Distribution Facilities, to conform with new storm protection rules to be enacted pursuant to Section 366.96, F.S. (2019), Public Utility Transmission and Distribution Storm Protection Plans<br><br>To consider whether to amend or repeal Rule 25-6.0342, F.A.C., Electric Infrastructure Storm Hardening, to conform with new storm protection rules to be enacted pursuant to Section 366.96, F.S. (2019), Public Utility Transmission and Distribution Storm Protection Plans<br><br>To amend Rule 25-6.036, F.A.C., Inspection of Plant, to clarify rule standards<br><br>To amend Rule 25-6.037, F.A.C., Extent of System Which Utility Shall Operate and Maintain, to update the rule and clarify standards |

LAWS NOT CREATING OR MODIFYING DUTIES OR AUTHORITY- SECTION 120.74(1)(b), F.S.

| Laws | Intent of Rulemaking |
|---|---|
| Section 366.05, F.S. (cont.) | To consider whether to amend or repeal Rule 25-6.044, F.A.C., Continuity of Service, to conform with new storm protection rules to be enacted pursuant to Section 366.96, F.S. (2019), Public Utility Transmission and Distribution Storm Protection Plans<br><br>To amend Rule 25-6.0440, F.A.C., Territorial Agreements for Electric Utilities, to clarify rule standards<br><br>To amend Rule 25-6.0441, F.A.C., Territorial Disputes for Electric Utilities, to clarify rule standards<br><br>To consider whether to amend or repeal Rule 25-6.0455, F.A.C., Annual Distribution Service Reliability Reports, to conform with new storm protection rules to be enacted pursuant to Section 366.96, F.S. (2019), Public Utility Transmission and Distribution Storm Protection Plans<br><br>To consider whether to amend Rule 25-6.049, F.A.C., Measuring Customer Service, to update rule requirements<br><br>To amend Rule 25-6.054, F.A.C., Laboratory Standards, to clarify rule requirements<br><br>To consider whether to amend or repeal Rule 25-6.061, F.A.C., Relocation of Poles, to conform with new storm protection rules to be enacted pursuant to Section 366.96, F.S. (2019), Public Utility Transmission and Distribution Storm Protection Plans<br><br>To consider whether to amend or repeal Rule 25-6.064, F.A.C., Contribution-in-Aid-of-Construction for Installation of New or Upgraded Facilities, to conform with new storm protection rules to be enacted pursuant to Section 366.96, F.S. (2019), Public Utility Transmission and Distribution Storm Protection Plans<br><br>To amend Rule 25-6.075, F.A.C., Definitions, to clarify the rule by specifying the rules to which the definitions apply<br><br>To consider whether to amend Rule 25-6.076, F.A.C., Rights of Way and Easements, to conform with new storm protection rules to be enacted pursuant to Section 366.96, F.S. (2019), Public Utility Transmission and Distribution Storm Protection Plans |

LAWS NOT CREATING OR MODIFYING DUTIES OR AUTHORITY- SECTION 120.74(1)(b), F.S.

| Laws | Intent of Rulemaking |
|---|---|
| Section 366.05, F.S. (cont.) | To consider whether to amend or repeal Rule 25-6.077, F.A.C., Installation of Underground Distribution Systems Within New Subdivisions, to conform with new storm protection rules to be enacted pursuant to Section 366.96, F.S. (2019), Public Utility Transmission and Distribution Storm Protection Plans<br><br>To amend Rule 25-6.104, F.A.C., Unauthorized Use of Energy, to clarify rule requirements<br><br>To consider whether to amend or repeal Rule 25-6.115, F.A.C., Facility Charges for Conversion of Existing Overhead Investor-owned Distribution Facilities, to conform with new storm protection rules to be enacted pursuant to Section 366.96, F.S. (2019), Public Utility Transmission and Distribution Storm Protection Plans<br><br>To consider whether to amend 25-7.0141, F.A.C., Allowance for Funds Used During Construction, to specify rule requirements<br><br>To amend Rule 25-14.013, F.A.C., Accounting for Deferred Income Taxes Under SFAS 109, to replace obsolete references to accounting standards with current standards; to update language in the rule to reference the Tax Cuts and Job Act of 2017; and to determine whether references to the IRS code and Revenue Procedure 88-12 need to be replaced with updated references<br><br>To amend Rule 25-14.014, F.A.C., Accounting for Asset Retirement Obligations Under SFAS 143, to replace the obsolete reference to SFAS 143 with the current standard |
| Section 366.055, F.S. | To amend Rule 25-6.036, F.A.C., Inspection of Plant, to clarify rule standards |
| Section 366.06, F.S. | To amend Rule 25-6.0141, F.A.C., Allowance for Funds Used During Construction, to remove outdated language<br><br>To amend Rule 25-6.0142, F.A.C., Uniform Retirement Units for Electric Utilities, to update the Code of Federal Regulations reference in subsection (1) and to include a link to the F.A.C. website for the List of Retirement Units that is incorporated by reference in subsection (3)<br><br>To amend Rule 25-6.033, F.A.C., Tariffs, to update the rule |

LAWS NOT CREATING OR MODIFYING DUTIES OR AUTHORITY- SECTION 120.74(1)(b), F.S.

| Laws | Intent of Rulemaking |
| --- | --- |
| Section 366.06, F.S. (cont.) | To consider whether to amend Rule 25-6.049, F.A.C., Measuring Customer Service, to update rule requirements<br><br>To consider whether to amend or repeal Rule 25-6.064, F.A.C., Contribution-in-Aid-of-Construction for Installation of New or Upgraded Facilities, to conform with new storm protection rules to be enacted pursuant to Section 366.96, F.S. (2019), Public Utility Transmission and Distribution Storm Protection Plans<br><br>To amend Rule 25-6.075, F.A.C., Definitions, to clarify the rule by specifying the rules to which the definitions apply<br><br>To consider whether to amend Rule 25-6.076, F.A.C., Rights of Way and Easements, to conform with new storm protection rules to be enacted pursuant to Section 366.96, F.S. (2019), Public Utility Transmission and Distribution Storm Protection Plans<br><br>To consider whether to amend or repeal Rule 25-6.077, F.A.C., Installation of Underground Distribution Systems Within New Subdivisions, to conform with new storm protection rules to be enacted pursuant to Section 366.96, F.S. (2019), Public Utility Transmission and Distribution Storm Protection Plans<br><br>To consider whether to amend or repeal Rule 25-6.078, F.A.C., Schedule of Charges, Installation of Underground Distribution Systems Within New Subdivisions, to conform with new storm protection rules to be enacted pursuant to Section 366.96, F.S. (2019), Public Utility Transmission and Distribution Storm Protection Plans<br><br>To amend Rule 25-6.080, F.A.C., Advances by Applicant, to conform with new storm protection rules to be enacted pursuant to Section 366.96, F.S. (2019), Public Utility Transmission and Distribution Storm Protection Plans<br><br>To consider whether to amend 25-7.0141, F.A.C., Allowance for Funds Used During Construction, to specify rule requirements |
| Section 366.08, F.S. | To amend Rule 25-6.0141, F.A.C., Allowance for Funds Used During Construction, to remove outdated language<br><br>To amend Rule 25-6.036, F.A.C., Inspection of Plant, to clarify rule standards |

LAWS NOT CREATING OR MODIFYING DUTIES OR AUTHORITY- SECTION 120.74(1)(b), F.S.

| Laws | Intent of Rulemaking |
|---|---|
| Section 366.093, F.S. | To amend paragraph (4)(a) of Rule 25-22.006, F.A.C., Confidential Information, to change the number of copies required to be filed to be consistent with current filing requirements |
| Section 366.81, F.S. | To consider whether to amend Rule 25-6.049, F.A.C., Measuring Customer Service, to update rule requirements |
| Section 366.82, F.S. | To consider whether to amend Rule 25-6.049, F.A.C., Measuring Customer Service, to update rule requirements |
| Section 366.96, F.S. | To adopt new Rule 25-6.030, F.A.C., Storm Protection Plan, to implement Section 366.96, F.S. (2019), Public Utility Transmission and Distribution Storm Protection Plans<br><br>To adopt new Rule 25-6.031, F.A.C., Storm Protection Plan Cost Recovery Clause, to implement Section 366.96, F.S. (2019), Public Utility Transmission and Distribution Storm Protection Plans |
| Section 367.022, F.S. | To adopt new Rule 25-30.0115, F.A.C., Definition of Landlord and Tenant, to define the terms “landlord” and “tenant” for purposes of implementing the exemption from Commission regulation under Section 367.022(5), F.S. |
| Section 367.071, F.S. | To amend Rule 25-30.0371, F.A.C., Acquisition Adjustments, to update the rule to address current industry practices |
| Section 367.081, F.S. | To consider whether to adopt a new rule in Chapter 25-30, F.A.C., to address water transmission distribution and wastewater collection used and useful considerations<br><br>To amend Rule 25-30.0371, F.A.C., Acquisition Adjustments, to update the rule to address current industry practice.<br><br>To amend Rule 25-30.360, F.A.C., Refunds, to clarify the procedure for customer refunds due to overbilling by water and wastewater companies<br><br>To amend Rule 25-30.460, F.A.C., Application for Miscellaneous Service Charges, to update and clarify definitions |
| Section 367.0814, F.S. | To amend Rule 25-30.360, F.A.C., Refunds, to clarify the procedure for customer refunds due to overbilling by water and wastewater companies |

LAWS NOT CREATING OR MODIFYING DUTIES OR AUTHORITY- SECTION 120.74(1)(b), F.S.

| Laws | Intent of Rulemaking |
|---|---|
| Section 367.0814, F.S. (cont.) | To amend Rule 25-30.457, F.A.C., Limited Alternative Rate Increase, to clarify rule standards |
| Section 367.082, F.S. | To amend Rule 25-30.360, F.A.C., Refunds, to clarify the procedure for customer refunds due to overbilling by water and wastewater companies |
| Section 367.091, F.S. | To amend Rule 25-30.335, F.A.C., Customer Billing, to update the rule to include guidance regarding the applicability of charges during a customer's absence<br><br>To amend Rule 25-30.350, F.A.C., Underbillings and Overbillings for Water and Wastewater Service, to clarify the procedure for customer refunds due to overbilling by water and wastewater companies |
| Section 367.121, F.S. | To amend Rule 25-14.012, F.A.C., Accounting for Postretirement Benefits Other Than Pensions, to replace obsolete references to Statement of Financial Accounting Standards 106 and 71 with current accounting standards<br><br>To amend Rule 25-14.013, F.A.C., Accounting for Deferred Income Taxes Under SFAS 109, to replace obsolete references to accounting standards with current standards; to update language in the rule to reference the Tax Cuts and Job Act of 2017; and to determine whether references to the IRS code and Revenue Procedure 88-12 need to be replaced with updated references<br><br>To amend Rule 25-14.014, F.A.C., Accounting for Asset Retirement Obligations Under SFAS 143, to replace the obsolete reference to SFAS 143 with the current standard<br><br>To amend Rule 25-30.0371, F.A.C., Acquisition Adjustments, to update rule to address current industry practices<br><br>To amend Rule 25-30.117, F.A.C., Accounting for Pension Costs, to replace the obsolete reference to SFAS 143 with the current standard<br><br>To amend Rule 25-30.335, F.A.C., Customer Billing, to update the rule to include guidance regarding the applicability of charges during a customer's absence |

LAWS NOT CREATING OR MODIFYING DUTIES OR AUTHORITY- SECTION 120.74(1)(b), F.S.

| Laws | Intent of Rulemaking |
|---|---|
| Section 367.121, F.S. (cont.) | To amend Rule 25-30.350, F.A.C., Underbillings and Overbillings for Water and Wastewater Service, to clarify the procedure for customer refunds due to overbilling by water and wastewater companies<br><br>To amend Rule 25-30.460, F.A.C., Application for Miscellaneous Service Charges, to update and clarify definitions |
| Section 367.156, F.S. | To amend paragraph (4)(a) of Rule 25-22.006, F.A.C., Confidential Information, to change the number of copies required to be filed to be consistent with current filing requirements |
| Section 368.108, F.S. | To amend paragraph (4)(a) of Rule 25-22.006, F.A.C., Confidential Information, to change the number of copies required to be filed to be consistent with current filing requirements |

UPDATES TO 2018 REGULATORY PLAN – SECTION 120.74(1)(c), F.S..

The Commission has no laws or updates to the 2018 Regulatory Plan to report pursuant to Section 120.74(1)(c), F.S.

**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 2, 2019

**TO:** Braulio L. Baez, Executive Director

**FROM:** Douglas Wright, Engineering Specialist I, Division of Engineering DW POE TB

**RE:** Review of 2019 Ten-Year Site Plan

**CRITICAL INFORMATION:** Place on October 17, 2019 Internal Affairs Agenda. Approval by the Commission is required by December 31, 2019.

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

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

DW:pz

Attachment

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

REVIEW OF THE

# 2019 TEN-YEAR SITE PLANS

OF FLORIDA’S ELECTRIC UTILITIES

FLORIDA PUBLIC SERVICE COMMISSION

NOVEMBER 2019

# Table of Contents

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# List of Ten-Year Site Plan Utilities

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

# Executive Summary

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

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

Pursuant to Section 186.801, Florida Statutes (F.S.), each generating electric utility must submit to the Commission a Ten-Year Site Plan which estimates the utility's power generating needs and the general locations of its proposed power plant sites over a 10-year planning horizon. The Ten-Year Site Plans of Florida's electric utility summarizes the results of each utility's IRP process and identifies proposed power plants and transmission facilities. The Commission is required to perform a preliminary study of each plan and classify each one as either "suitable" or "unsuitable." This document represents the review of the 2019 Ten-Year Site Plans for Florida's electric utilities, filed by 11 reporting utilities.[1]

[1]Investor-owned utilities filing 2019 Ten-Year Site Plans include Florida Power & Light Company (FPL), Duke Energy Florida, LLC. (DEF), Tampa Electric Company (TECO), and Gulf Power Company (GPC). Municipal utilities filing 2019 Ten-Year Site Plans 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 2019 Ten-Year Site Plan.

All findings of the Commission are made available to the Florida Department of Environmental Protection for its consideration at any subsequent certification proceeding pursuant to the Electrical Power Plant Siting Act or the Electric Transmission Line Siting Act.[2] In addition, this document is sent to the Florida Department of Agriculture and Consumer Services pursuant to Section 377.703(2)(e), F.S., which requires the Commission provide a report on electricity and natural gas forecasts.

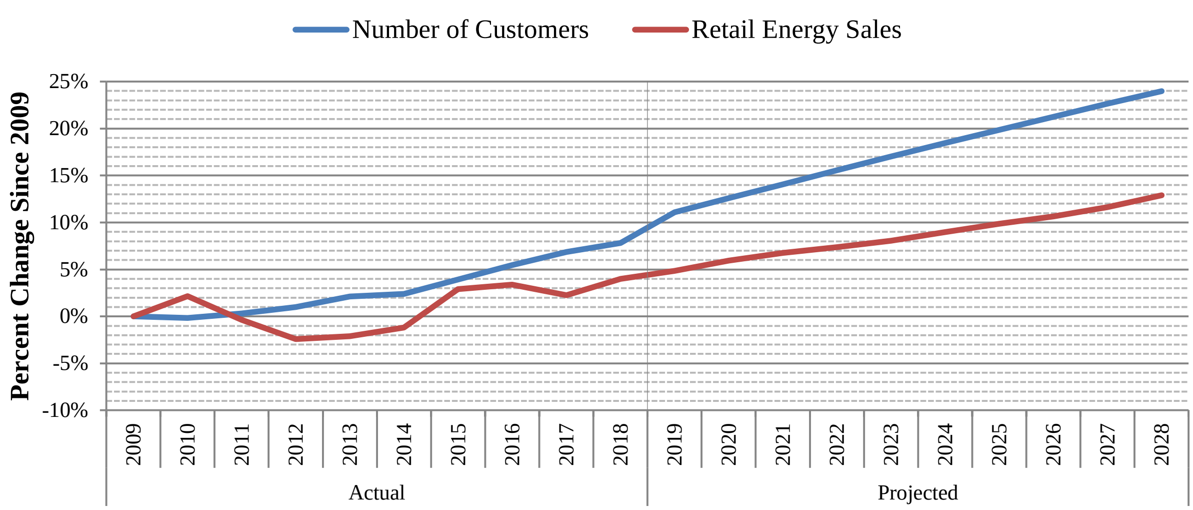
## *Review of the 2019 Ten-Year Site Plans*

The Commission has divided this review into two portions: (1) a Statewide Perspective, which covers the whole of Florida; and (2) Utility Perspectives, which address each of the reporting utilities. From a statewide perspective, the Commission has reviewed the implications of the combined trends of Florida's electric utilities regarding load forecasting, renewable generation, and traditional generation.

### Load Forecasting

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

**Figure 1: State of Florida - Growth in Customers and Sales**




Source: FRCC 2019 Regional Load and Resource Plan

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

## Renewable Generation

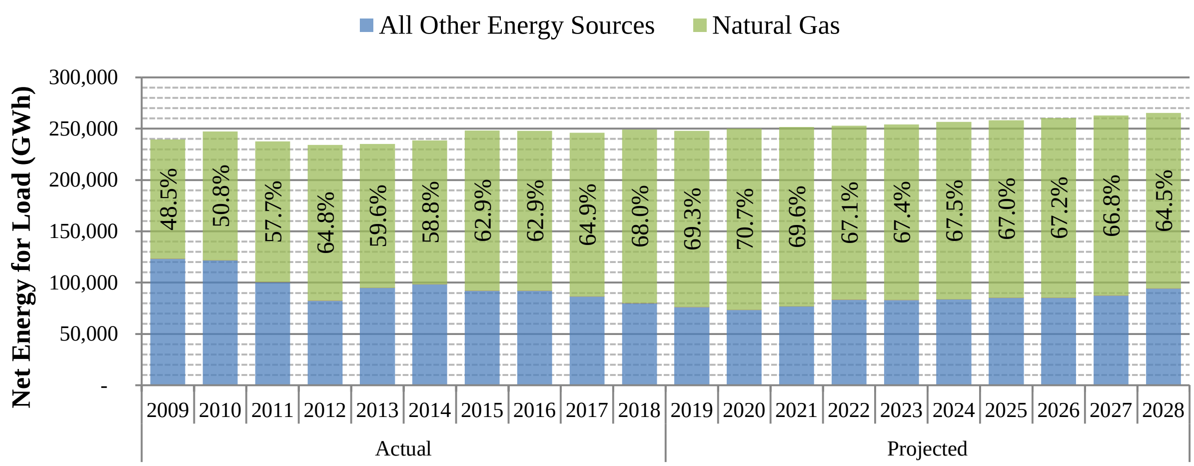
Renewable resources continue to expand in Florida, with approximately 3,335 MW of renewable generating capacity currently in Florida. The majority of installed renewable capacity is represented by solar, biomass, and municipal solid waste. These make approximately 78 percent of Florida's renewables. Other major renewable types, in order of capacity contribution, include waste heat, wind, landfill gas, and hydroelectric. Notably, Florida electric customers had installed 317 MW of demand-side renewable capacity at the end of 2018, resulting in an increase of 55 percent from 2017.

Florida's total renewable resources are expected to increase by an estimated 10,704 MW over the 10-year planning period, excluding any potential demand-side renewable energy additions. Over three-quarters of the projected capacity additions are solar photovoltaic generation. Some utilities are including a portion of these solar resources as a firm resource for reliability considerations. Reasons given for these additions are the continued reduction in the price of solar facilities, availability of utility property with access to the grid, and actual performance data obtained during solar demonstration projects. If these conditions continue, cost-effective forms of renewable generation will continue to improve the state's fuel diversity and reduce dependence on fossil fuels.

## Traditional Generation

Generating capacity within Florida is anticipated to grow to meet the increase in customer demand, with an approximate net increase of 6,987 MW of utility-owned traditional generation over the planning horizon. This figure represents an increase from the previous year's planned net increase of 3,794 MW. Natural gas consumption is expected to remain somewhat steady and the dominant fuel over the planning horizon, with usage in 2018 at approximately 68 percent of the state's net energy for load (NEL). Figure 2 illustrates the use of natural gas as a generating fuel for electricity production in Florida.

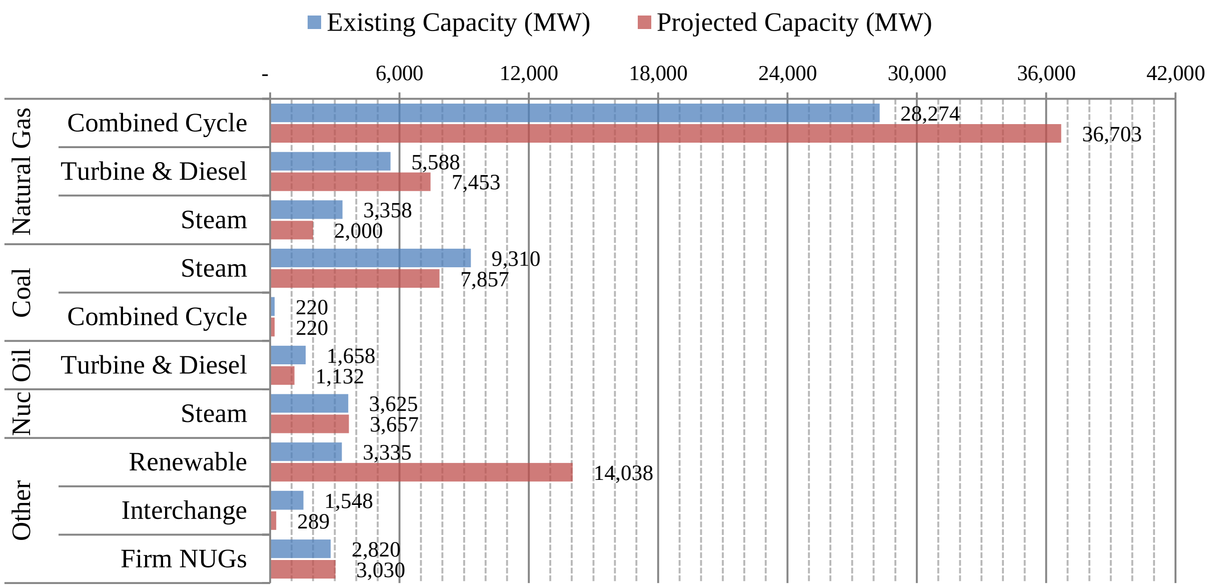
**Figure 2: State of Florida - Natural Gas Contribution to Energy Consumption**




Source: FRCC 2010-2019 Regional Load and Resource Plan

Figure 3 illustrates the present and future aggregate capacity mix of Florida based on the 2019 Ten-Year Site Plans. The capacity values in Figure 3 incorporate all proposed additions, changes, and retirements planned during the 10-year period. While natural gas-fired generating units represent a majority of capacity within the state, renewable capacity additions make up the majority of the projected net increase in generation capacity over the planning period. Given its projected net increase, renewable capacity is expected to surpass coal generation during the 10-year planning period becoming the second highest installed capacity source in the state.

**Figure 3: State of Florida - Current and Projected Installed Capacity by Fuel**




Source: FRCC 2019 Regional Load and Resource Plan & TYSP Data Responses

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

**Table 1: State of Florida - Planned Units Requiring a Determination of Need**

| Year | Utility Name | Unit Name | Fuel & Unit Type | Net Capacity (Sum MW) |
|---|---|---|---|---|
| 2024 | GPC | Combined Cycle 2 | NG – CC | 595 |
| 2026 | FPL | Unsited CC Facility | NG – CC | 1,886 |
| | | | **Total** | **2,481** |

Source: 2019 Ten-Year Site Plans

## *Future Concerns*

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

On August 21, 2018, as part of its proposed Affordable Clean Energy (ACE) Rule, the EPA proposed updates to the New Source Review permitting program that may impact utility decisions regarding power plant modifications and reconstruction. While the ACE rule has been finalized, EPA has taken no final actions regarding the New Source Review permitting program. These recent regulatory developments will be addressed in a subsequent Ten-Year Site Plan review, and the potential effects on Florida's electric utilities are not considered as part of this review.

## *Conclusion*

The Commission has reviewed the 2019 Ten-Year Site Plans and finds that the projections of load growth appear reasonable. The reporting utilities have identified sufficient additional generation facilities to maintain an adequate supply of electricity at a reasonable cost. The Commission will continue to monitor the impact of current and proposed EPA Rules and the state's dependence on natural gas for electricity production.

Based on its review, the Commission finds the 2019 Ten-Year Site Plans to be suitable for planning purposes. Since the Plans are not a binding plan of action for electric utilities, the Commission's classification of these Plans as suitable or unsuitable does not constitute a finding or determination in docketed matters before the Commission. The Commission may address any concerns raised by a utility's Ten-Year Site Plan at a public hearing.

# Introduction

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

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

## *Statutory Authority*

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

### Applicable Utilities

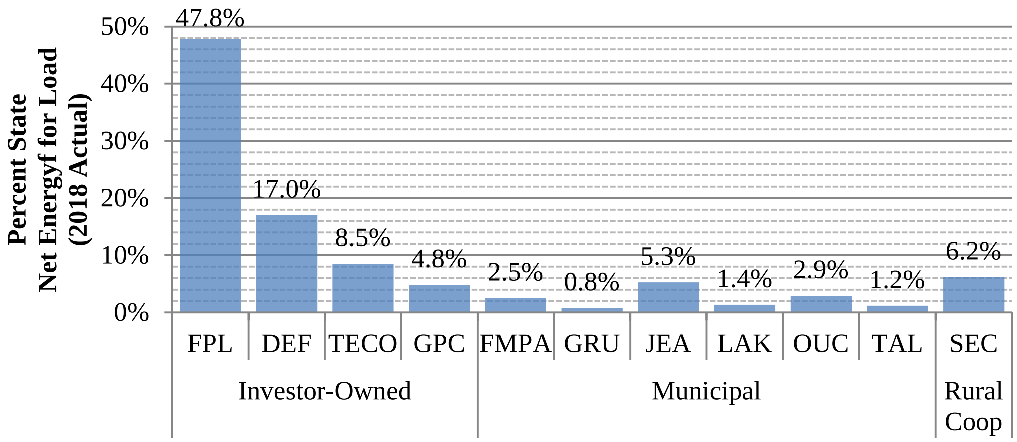
Florida is served by 58 electric utilities, including 5 investor-owned utilities, 35 municipal utilities, and 18 rural electric cooperatives. Pursuant to Rule 25-22.071(1), F.A.C., only generating electric utilities with an existing capacity above 250 megawatts (MW) or a planned unit with a capacity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

In 2019, 11 utilities met these requirements and filed a Ten-Year Site Plan, including 4 investor-owned utilities, 6 municipal utilities, and 1 rural electric cooperative. The investor-owned utilities, in order of size, are Florida Power & Light Company (FPL), Duke Energy Florida, LLC (DEF), Tampa Electric Company (TECO), and Gulf Power Company (GPC). The municipal utilities, in alphabetical order, are Florida Municipal Power Agency (FMPA), Gainesville

Regional Utilities (GRU), JEA (formerly Jacksonville Electric Authority), Lakeland Electric (LAK), Orlando Utilities Commission (OUC), and City of Tallahassee Utilities (TAL). The sole rural electric cooperative filing a 2019 Plan is Seminole Electric Cooperative (SEC). Collectively, these utilities are referred to as the Ten-Year Site Plan Utilities (TYSP Utilities).

Figure 4 illustrates the comparative size of the TYSP Utilities, in terms of each utility's percentage share of the state's retail energy sales in 2018. Combined, the reporting investor-owned utilities account for 78 percent of the state's retail energy sales. The reporting municipal and cooperative utilities make up approximately 20 percent of the state's retail energy sales.

**Figure 4: TYSP Utilities - Comparison of Reporting Electric Utility Size**




Source: 2019 Ten-Year Site Plans & FRCC 2019 Regional Load and Resource Plan

### Required Content

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

## *Additional Resources*

The Florida Reliability Coordinating Council (FRCC) is tasked with reporting and collecting information on both a statewide basis and for Peninsular Florida, which excludes the area west of the Apalachicola River. This provides aggregate data for the Commission's review. Each year, the FRCC publishes a Regional Load and Resource Plan, which contains historic and forecast data on demand and energy, capacity and reserves, and proposed new generating units and transmission line additions. In addition, the FRCC publishes an annual Reliability Report which is also relied upon by the Commission. For certain comparisons, additional data from various government agencies is relied upon, including the Energy Information Administration and the Florida Department of Highway Safety and Motor Vehicles.

Commission staff held a public workshop on October 3, 2019, to facilitate discussion of the annual planning process and allow for public comments. A presentation was conducted by the FRCC summarizing the 2019 Regional Load and Resource Plan and other related matters, including fuel supply reliability and the reliability considerations of utility solar generation additions.

## *Structure of the Commission's Review*

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

## *Conclusion*

Based on its review, the Commission finds all 11 reporting utilities' 2019 Ten-Year Site Plans to be suitable for planning purposes. During its review, the Commission has determined that the projections for load growth appear reasonable and that the reporting utilities have identified sufficient generation facilities to maintain an adequate supply of electricity at a reasonable cost.

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

# Statewide Perspective

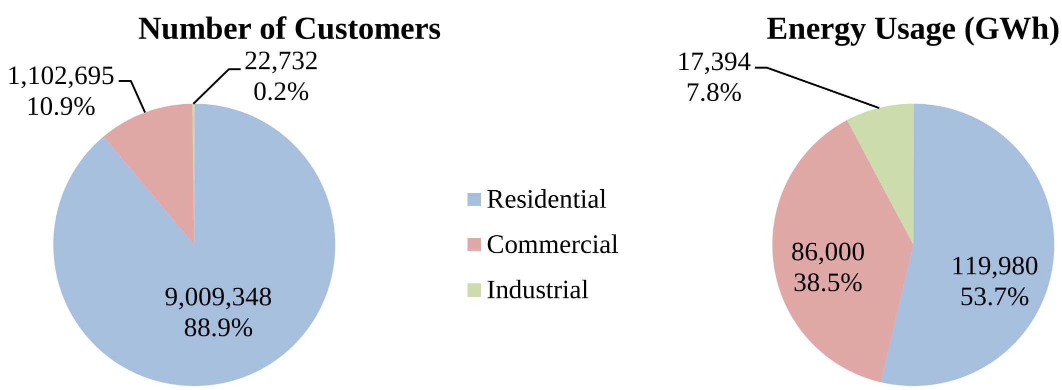
# Load Forecasting

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

## *Electric Customer Composition*

Utility companies categorize their customers by residential, commercial, and industrial classes. As of January 1, 2019, residential customers account for 88.9 percent of the total, followed by commercial (10.9 percent) and industrial (0.2 percent) customers, as illustrated in Figure 5. Commercial and industrial customers make up a sizeable percentage of energy sales, due to their higher energy usage per customer.

**Figure 5: State of Florida - Electric Customer Composition in 2018**



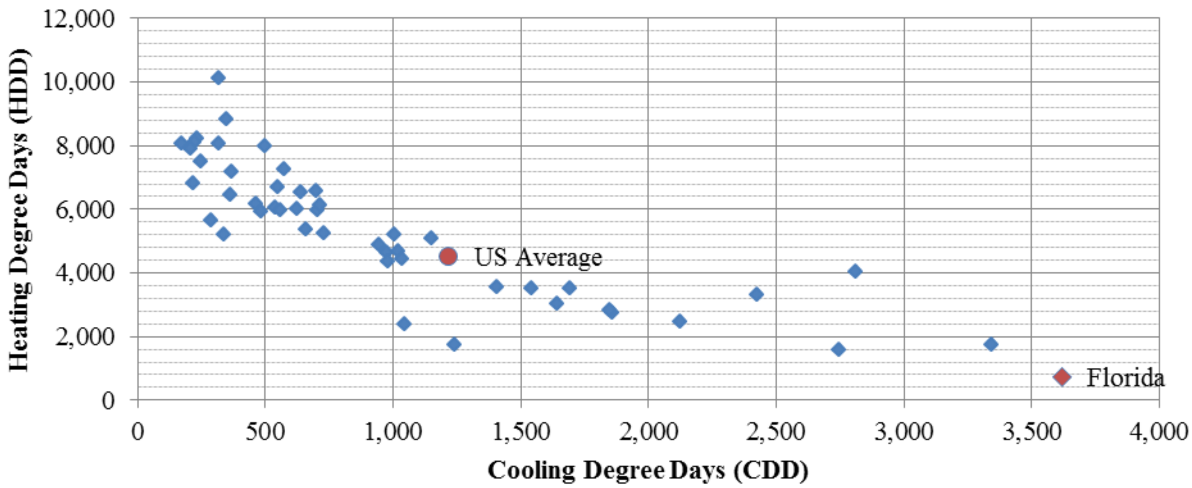

Source: FRCC 2019 Regional Load and Resource Plan

Residential customers in Florida make up the largest portion of retail energy sales. Florida's residential customers accounted for 53.7 percent of retail energy sales in 2018, compared to a national average of 38.5 percent.[3] As a result, Florida's utilities are influenced more by trends in residential energy usage, which tend to be associated with weather conditions. In addition, Florida's residential customers rely more upon electricity for heating than the national average, with only a small portion using alternate fuels such as natural gas or oil for home heating needs.

[3]U.S. Energy Information Administration June 2019 Electric Power Monthly.

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

**Figure 6: National - Climate Data by State (Continental US)**

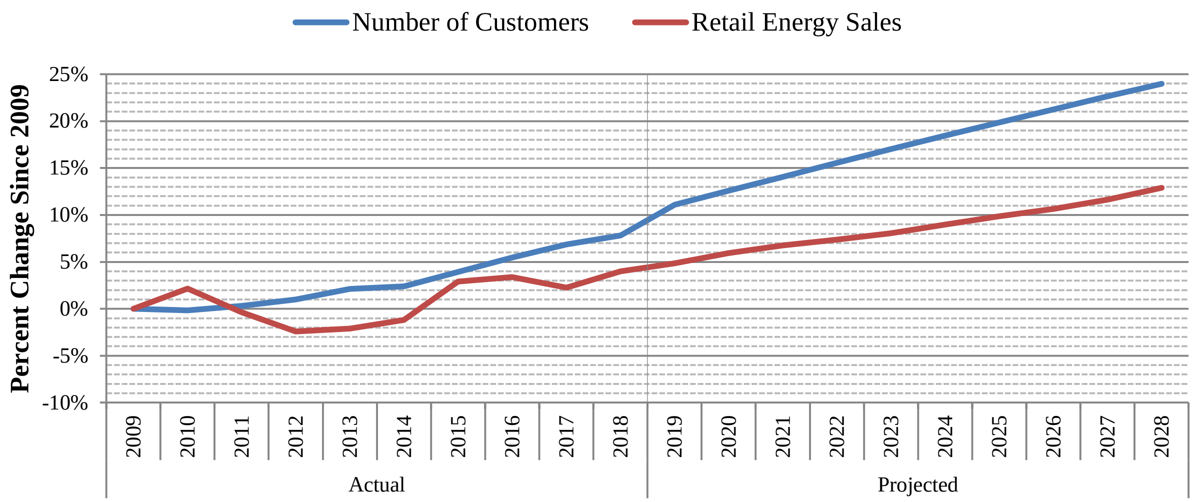



Source: National Oceanic and Atmospheric Administration, Historical Climatology Series 5-1 and 5-2

## *Growth Projections*

For the next 10-year period, Florida's retail sales are anticipated to grow at 0.83 percent per year, a 90 percent increase over the 0.43 percent annual increase experienced during the 2009–2018 period. The current divide between customers and retail sales is anticipated to remain similar over the 10-year period, with customers growing at an average annual rate of about 1.23 percent, while retail sales increase by about 0.83 percent annually. Florida's electric utilities are projecting an increase in economic growth in the state. The trends are showcased in Figure 7.

**Figure 7: State of Florida - Growth in Customers and Sales**



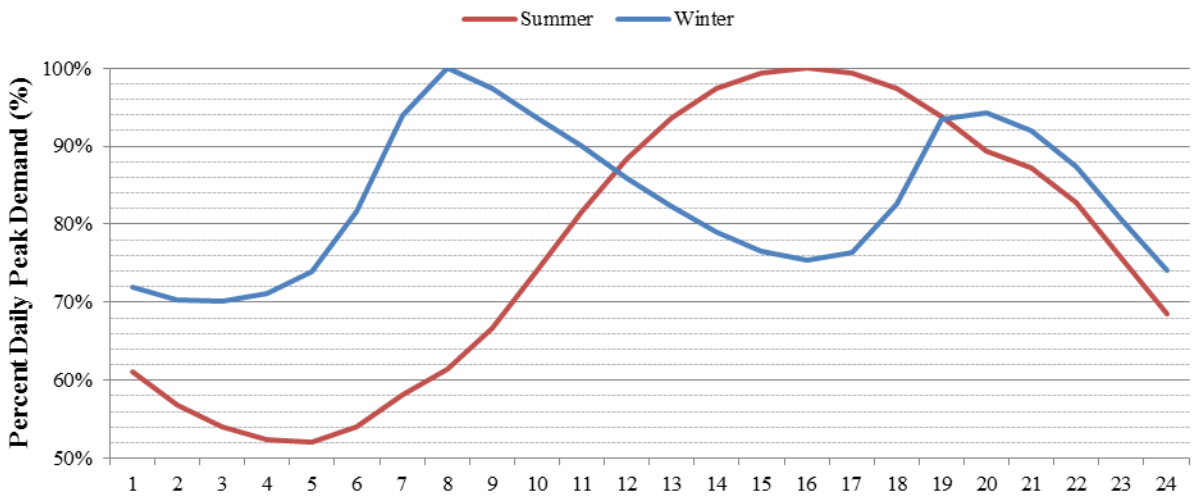

Source: FRCC 2019 Regional Load and Resource Plan

## *Peak Demand*

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

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

**Figure 8: TYSP Utilities - Example Daily Load Curves**

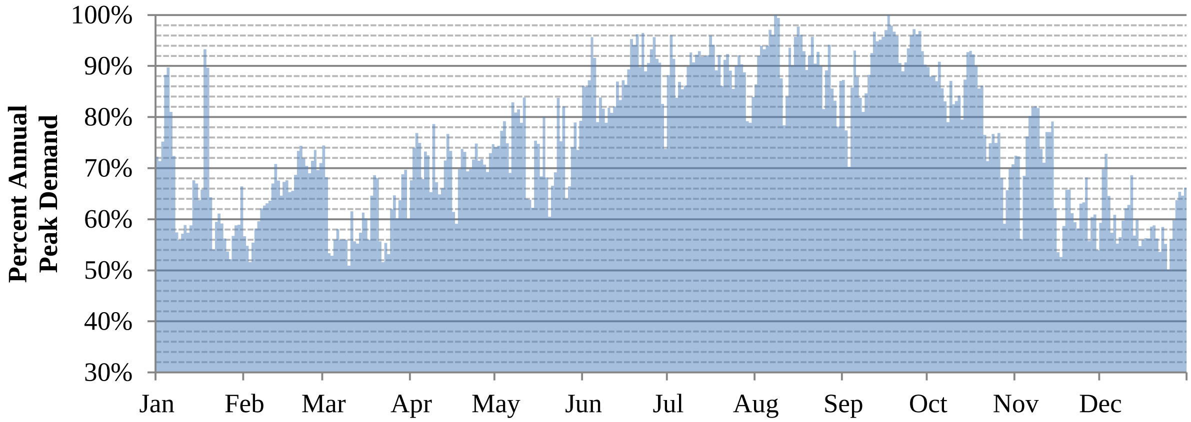



Source: TYSP Utilities' Data Responses

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

As daily load varies, so do seasonal loads. Figure 9 shows the 2018 daily peak demand as a percentage of the annual peak demand for the reporting investor-owned utilities combined. Typically, winter peaks are short events while summer demand tends to stay at near peak levels for longer periods. The periods between seasonal peaks are referred to as shoulder months, in which the utilities take advantage of lower demand to perform maintenance without impacting their ability to meet daily peak demand.

**Figure 9: TYSP Utilities - Daily Peak Demand (2018 Actual)**




Source: TYSP Utilities' Data Responses (Investor-Owned Utilities Only)

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

## *Electric Vehicles*

Utilities also examine other trends that may impact customer peak demand and energy consumption. These include new sources of energy consumption, such as electric vehicles, which can be considered analogous to home air conditioning systems in terms of system demand. The reporting electric utilities estimate approximately 37,449 electric plug-in vehicles were operating in Florida at the end of 2018. The Florida Department of Highway Safety and Motor Vehicles lists the number of registered automobiles, heavy trucks, and buses in Florida, as of January 6, 2019, at 16.8 million vehicles, resulting in an approximate 0.22 percent penetration rate of electric vehicles.[4]

Florida's electric utilities anticipate growth in the electric vehicle market, as illustrated in Table 2. Electric vehicle ownership is anticipated to grow rapidly throughout the planning period, resulting in approximately 506,495 electric vehicles operating within the electric service territories by the end of 2028.

[4]Florida Department of Highway Safety and Motor Vehicles January 2019 Vehicle and Vessel Reports and Statistics.

**Table 2: TYSP Utilities - Estimated Number of Electric Vehicles by Service Territory**

| YEAR | FPL | DEF | TECO | GULF | JEA | GRU | TAL | TOTAL |
|---|---|---|---|---|---|---|---|---|
| **2018** | 22,848 | 7,468 | 3,666 | 559 | 300 | 1,229 | 1,379 | **37,449** |
| **2019** | 30,409 | 11,149 | 4,758 | 630 | 330 | 1,601 | 1,392 | **49,639** |
| **2020** | 40,252 | 16,080 | 5,896 | 698 | 363 | 2,029 | 1,406 | **66,724** |
| **2021** | 53,059 | 22,669 | 7,081 | 761 | 399 | 2,507 | 1,420 | **87,896** |
| **2022** | 69,803 | 31,506 | 8,309 | 833 | 439 | 3,037 | 1,435 | **115,361** |
| **2023** | 91,594 | 42,591 | 9,582 | 917 | 483 | 3,622 | 1,449 | **150,238** |
| **2024** | 119,979 | 54,478 | 11,057 | 1,000 | 531 | 4,262 | 1,463 | **192,770** |
| **2025** | 156,857 | 69,019 | 13,155 | 1,135 | 584 | 4,956 | 1,478 | **247,184** |
| **2026** | 204,738 | 86,038 | 15,638 | 1,298 | 642 | 5,707 | 1,493 | **315,554** |
| **2027** | 266,883 | 104,722 | 18,605 | 1,505 | 706 | 6,517 | 1,508 | **400,447** |
| **2028** | 347,655 | 125,363 | 22,033 | 1,752 | 777 | 7,390 | 1,524 | **506,495** |

Source: TYSP Utilities' Data Responses

Table 3 illustrates the TYSP Utilities' projections of energy consumed by electric vehicles through 2028. The anticipated growth would result in an annual energy consumption of 1,861.3 GWh by 2028. Current estimates represent a less than 1 percent impact on net energy for load by 2028.

**Table 3: TYSP Utilities - Estimated Electric Vehicle Annual Energy Consumption (GWh)**

| YEAR | FPL | DEF | TECO | GULF | JEA | GRU | TAL* | TOTAL |
|---|---|---|---|---|---|---|---|---|
| **2018** | - | - | 27.0 | 1.9 | 1.0 | - | - | **29.9** |
| **2019** | 25.9 | 5.7 | 37.1 | 2.1 | 1.1 | 6.7 | - | **78.6** |
| **2020** | 62.1 | 20.8 | 45.9 | 2.3 | 1.2 | 8.6 | - | **140.9** |
| **2021** | 109.5 | 40.9 | 55.1 | 2.4 | 1.3 | 10.7 | - | **219.9** |
| **2022** | 174.4 | 68.0 | 64.6 | 2.6 | 1.4 | 13.0 | - | **324.1** |
| **2023** | 259.8 | 103.5 | 74.5 | 2.8 | 1.5 | 15.7 | - | **457.8** |
| **2024** | 372.7 | 145.6 | 85.9 | 3.0 | 1.7 | 18.6 | - | **627.4** |
| **2025** | 518.8 | 193.3 | 102.1 | 3.4 | 1.9 | 21.8 | - | **841.1** |
| **2026** | 706.5 | 251.3 | 121.2 | 3.9 | 2.1 | 25.2 | - | **1,110.1** |
| **2027** | 946.9 | 317.2 | 144.0 | 4.5 | 2.3 | 29.0 | - | **1,443.9** |
| **2028** | 1,258.9 | 391.1 | 170.4 | 5.4 | 2.5 | 33.1 | - | **1,861.3** |

Source: TYSP Utilities' Data Responses
*City of Tallahassee Utilities did not provide estimates of electric vehicle annual energy consumption.

The effect of increased electric vehicle ownership on peak demand is more difficult to determine. While comparable in electric demand to a home air conditioning system, the time of charging and whether charging would be shifted away from periods of peak demand are uncertain. As electric vehicle ownership increases, the projected impacts of electric vehicles on system peak demand should become clearer and electric utilities will be better positioned to respond accordingly.

In order to investigate potential unknowns associated with the electric vehicle energy market in Florida, several utilities have initiated Commission-approved electric vehicle pilot programs. The nature of these pilot programs vary among utilities, but include investments in vehicle charging infrastructure, research partnerships, and electric vehicle rebate programs. Utilities will note key findings and track metrics of interest within these pilot programs to help inform the Commission regarding the future power needs of electric vehicles in Florida.

## *Demand-Side Management*

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

### Florida Energy Efficiency and Conservation Act (FEECA)

The Florida Legislature has directed the Commission to encourage utilities to decrease the growth rates in seasonal peak demand and annual energy consumption by establishing the FEECA, which consists of Sections 366.80 through 366.83 and Section 403.519, F.S. Under FEECA, the Commission is required to set goals for seasonal demand and annual energy reduction for seven electric utilities and one natural gas utility, known as the FEECA Utilities. These include the five investor-owned electric utilities, FPL, DEF, TECO, GPC, and Florida Public Utility Company (which is a non-generating utility and therefore does not file a Ten-Year Site Plan), two municipal electric utilities, JEA and OUC, and an investor-owned natural gas utility, Peoples Gas System. The electric FEECA utilities represented approximately 87 percent of 2018 retail electric sales in Florida.

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

The last FEECA goal-setting proceeding was completed in December 2014, establishing goals for the period 2015 through 2024. During 2015, the Commission reviewed the FEECA Utilities' proposed DSM Plans to comply with the established goals, approving the plans with some modifications in July 2015. The FEECA Utilities are petitioning the Commission in the current FEECA goal-setting proceeding to approve annual conservation goals for the period 2020 through 2029. The Commission will review DSM Plans that address these goals in 2020, following FEECA goal-setting. All FEECA Utilities that filed a TYSP except FPL incorporated in their planning the impacts of the DSM goals established during the 2014 FEECA goal-setting proceeding. FPL instead based its planning on its proposed DSM goals in the current FEECA proceeding. It is anticipated that all FEECA Utilities will adjust their planning to incorporate the 2020-2029 DSM goals once established by the Commission.

## DSM Programs

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

Interruptible load is achieved through the use of agreements with large customers to allow the utility to interrupt the customer's load, reducing the generation required to meet system demand. Interrupted customers may use back-up generation to fill their energy needs, or cease operation until the interruption has passed. A subtype of interruptible load is curtailable load, which allow the utility to interrupt only a portion of the customer's load. In exchange for the ability to interrupt these customers, the utility offers a discounted rate for energy or other credits which are paid for by all ratepayers.

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

As of December 31, 2018, demand response available for reduction of peak load is 2,951 MW for summer peak and 2,887 MW for winter peak. Demand response is anticipated to increase to approximately 3,488 MW for summer peak and 3,321 MW for winter peak by the end of the planning period in 2028.[5]

Energy efficiency or conservation measures also have an impact on peak demand, and due to their passive nature do not require activation by the utility. Conservation measures include improvements in a home or business' building envelope to reduce heating or cooling needs, or the installation of more efficient appliances. By installing additional insulation, energy-efficient windows or window films, and more efficient appliances, customers can reduce both their peak demand and annual energy consumption, leading to reductions in customer bills. Demand-side management programs work in conjunction with building codes and appliance efficiency standards to increase energy savings above the minimum required by local, state, or federal regulations. As of 2019, energy efficiency is responsible for peak load reductions of 4,454 MW for summer peak and 3,968 MW for winter peak. Energy efficiency is anticipated to increase to approximately 5,169 MW for summer peak and 4,622 MW for winter peak by the end of the planning period in 2028.[6]

[5] Ten-Year Site Plan Utilities' Data Responses.
[6] Id.

## *Forecast Load & Peak Demand*

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

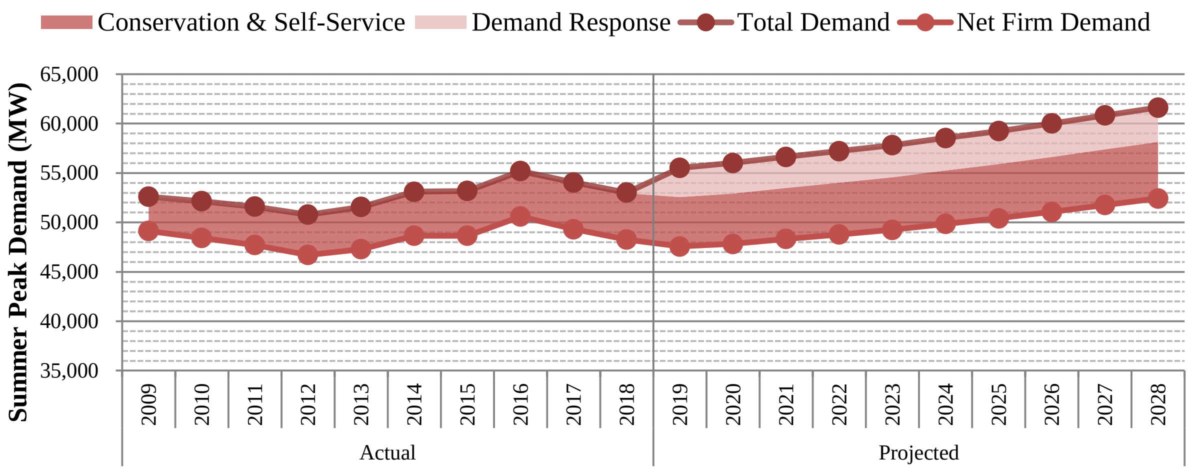
Demand-side management, including demand response and energy efficiency, along with self-service generation is included in each figure for seasonal peak demand and annual energy for load. The total demand or total energy for load represents what otherwise would need to be served if not for the impact of these programs and self-service generators. The net firm demand is used as a planning number for the calculation of generating reserves and determination of generation needs for Florida's electric utilities.

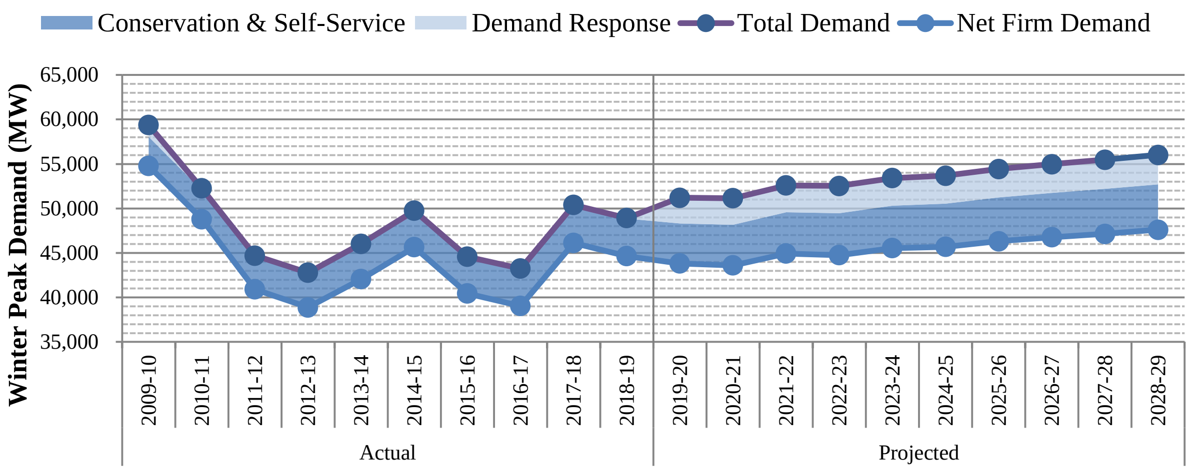
Demand response is included in Figure 10 in two different ways based upon the time period considered. For historic values of seasonal demand, the actual rates of demand response activation are shown, not the full amount of demand response that was available at the time. Overall, demand response has only been partially activated as sufficient generation assets were available during the annual peak. Residential load management has been called upon to a limited degree during peak periods, with a lesser amount of interruptible load activated. The primary exception to this trend was the winter of 2009-2010, when a larger portion of the available demand response resources were called upon.

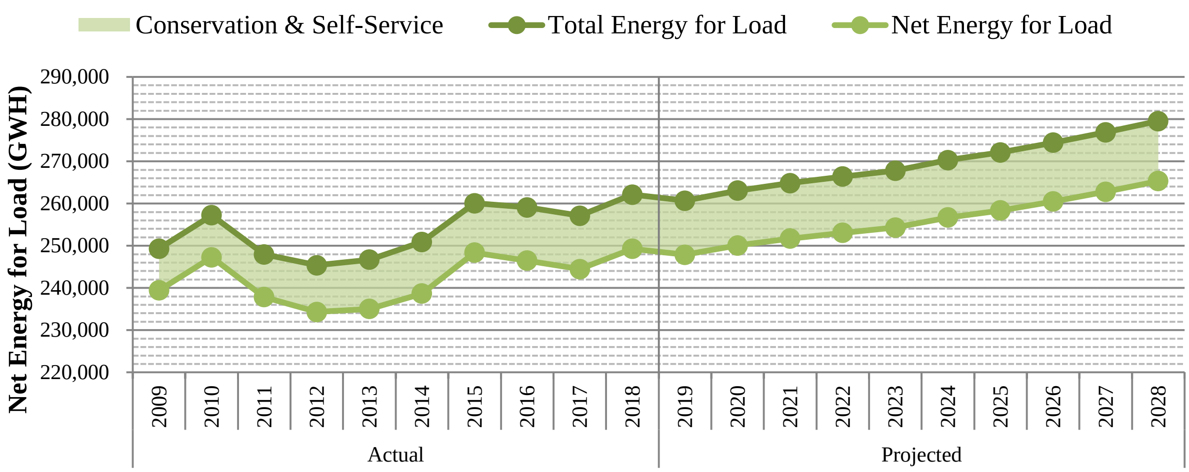
For forecast values of seasonal demand, it is assumed that all demand response resources will be activated during peak. The assumption of all demand response being activated reduces generation planning need. Based on operating conditions in the future, if an electric utility has sufficient generating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

As previously discussed, Florida is normally a summer-peaking state. Only two of the past ten years have had higher winter net firm demand than summer, and all ten of the forecast years are anticipated to be summer peaking. Based upon current forecasts using normalized weather data, Florida's electric utilities do not anticipate exceeding the winter 2009-2010 peak during the planning period.

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




Source: FRCC 2019 Regional Load and Resource Plan

## Forecast Methodology

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

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

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

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

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

For each reporting electric utility, the Commission reviewed the historic forecast accuracy of past retail energy sales forecasts. The review methodology, previously used by the Commission, involves comparing actual retail sales for a given year to energy sales forecasts made three, four, and five years prior. For example, the actual 2018 retail energy sales were compared to the forecasts made in 2013, 2014, and 2015. These differences, expressed as a percentage error rate, are used to determine each utility's historic forecast accuracy using a five-year rolling average. An average error with a negative value indicates an under-forecast, while a positive value represents an over-forecast. An absolute average error provides an indication of the total magnitude of error, regardless of the tendency to under or over forecast.

For the 2019 Ten-Year Site Plans, determining the accuracy of the five-year rolling average forecasts involves comparing the actual retail energy sales for the period 2014 through 2018 to forecasts made between 2009 and 2015. As discussed previously, the period before the 2007 recession experienced a higher annual growth rate for retail energy sales than the post-crisis period. As most electric utilities and macroeconomic forecasters did not predict the financial crisis, the economic impact and its resulting effect on retail energy sales of Florida's electric utilities were not included in these projections. Therefore, the use of a metric that compares pre-recession forecasts with pre-recession actual data has a high rate of error.

Table 4 shows that the forecast errors (the difference between the actual data and the forecasts made five years prior) were increasing with time starting in 2012 due to the unexpected impact of the recession and its impact on retail energy sales in Florida. However, the forecast errors have started to return to lower levels as utility retail sales forecasts include more post-recession years. This was indicated by the actual sales data provided in the 2017 Ten-Year Site Plans. The forecasting error rates (five-year rolling average and/or absolute average) derived from 2018 and 2019 Ten-Year Site Plans show continued decreases.

**Table 4: TYSP Utilities - Accuracy of Retail Energy Sales Forecasts[7]**
**(Five-Year Rolling Average)**

| Year | Five-Year Analysis Period | Forecast Years Analyzed | Forecast Error (%) | |
|---|---|---|---|---|
| | | | Average | Absolute Average |
| **2012** | 2011-2007 | 2008-2002 | 11.99% | 11.99% |
| **2013** | 2012-2008 | 2009-2003 | 15.22% | 15.22% |
| **2014** | 2013-2009 | 2010-2004 | 16.27% | 16.27% |
| **2015** | 2014-2010 | 2011-2005 | 14.99% | 14.99% |
| **2016** | 2015-2011 | 2012-2006 | 12.55% | 12.55% |
| **2017** | 2016-2012 | 2013-2007 | 9.19% | 9.19% |
| **2018** | 2017-2013 | 2014-2008 | 6.07% | 6.07% |
| **2019** | 2018-2014 | 2015-2009 | 3.58% | 3.58% |

Source: 2002-2019 Ten-Year Site Plans

To verify whether more recent forecasts lowered the error rates, an additional analysis was conducted to determine with more detail, the source of high error rates in terms of forecast timing. Table 5 provides the error rates for forecasts made between one to six years prior, along with the three-year average and absolute average error rates for the forecasting period of three- to five-year period used in the analysis in Table 4.

[7]During the course of review of the 2019 Ten-Year Site Plans, certain utilities amended the actual data of their Retail Energy Sales that was reported in previous TYSPs in responses to staff-issued data requests. Consequently, the calculated error rates of utilities' historical forecast have been changed in comparison with what staff presented in the "Review of the 2018 Ten-Year Site Plans."

As displayed in Table 5 the utilities' retail energy sales forecasts show a consistent positive error rate beginning in 2007. The error rates reach a peak during the period 2009 through 2013. Starting in 2014, the error rates have declined considerably; and the error rates calculated based on recent years' TYSPs continue to show lower forecast error rates, compared to the peak value of the error rates related to 2009-2013 sales forecasts. Additionally, the last four years' one-year ahead forecasts and the last years' two-year ahead forecast all bear negative error rates (under-forecasts), with the current TYSPs showing a very small error rate.

**Table 5: TYSP Utilities – Accuracy of Retail Energy Sales Forecasts – Annual Analysis[8]**
**(Analysis of Annual and Three-Year Average of Three- to Five- Prior Years)**

| Year | Annual Forecast Error Rate (%) | | | | | | 3-5 Year Error (%) | |
|---|---|---|---|---|---|---|---|---|
| | Years Prior | | | | | | Average | Absolute Average |
| | 6 | 5 | 4 | 3 | 2 | 1 | | |
| **2007** | 0.57% | 2.26% | 3.49% | 3.59% | 4.20% | 3.05% | 3.11% | 3.11% |
| **2008** | 7.02% | 8.40% | 8.56% | 9.97% | 9.24% | 8.34% | 8.98% | 8.98% |
| **2009** | 12.05% | 12.25% | 14.58% | 14.01% | 12.79% | 10.27% | 13.61% | 13.61% |
| **2010** | 13.03% | 15.68% | 14.99% | 13.81% | 10.65% | -0.65% | 14.83% | 14.83% |
| **2011** | 21.67% | 20.91% | 20.22% | 17.14% | 3.89% | 0.18% | 19.42% | 19.42% |
| **2012** | 26.43% | 26.12% | 23.16% | 8.58% | 4.01% | 3.81% | 19.29% | 19.29% |
| **2013** | 28.71% | 26.42% | 10.11% | 6.09% | 5.69% | 3.08% | 14.21% | 14.21% |
| **2014** | 27.28% | 9.80% | 6.10% | 5.73% | 2.84% | 2.21% | 7.21% | 7.21% |
| **2015** | 7.29% | 3.63% | 3.23% | 1.02% | 0.00% | -1.17% | 2.63% | 2.63% |
| **2016** | 4.33% | 4.38% | 2.28% | 1.25% | 0.20% | -0.97% | 2.64% | 2.64% |
| **2017** | 6.99% | 4.93% | 3.59% | 2.53% | 1.57% | -0.07% | 3.68% | 3.68% |
| **2018** | 4.28% | 2.76% | 1.76% | 0.75% | -1.13% | -1.08% | 1.76% | 1.76% |

Source: 2002-2019 Ten-Year Site Plans

Barring any unforeseen economic crises or atypical weather patterns, average forecasted energy sales error rates in the next few years are likely to be more reflective of the error rates shown for 2015 through 2018 in Table 5 than the significantly higher error rates shown in earlier years associated with the recession. It is important to recognize that the dynamic nature of the economy and the weather continue to present a degree of uncertainty for Florida utilities' load forecasts, ultimately impacting the accuracy of energy sales forecasts.

[8]During the course of review of the 2019 Ten-Year Site Plans, certain utilities amended the actual data of their Retail Energy Sales that was reported in previous TYSPs in responses to staff-issued data requests. Consequently, the calculated error rates of utilities' historical forecast have been changed in comparison with what staff presented in the "Review of the 2018 Ten-Year Site Plans."

# Renewable Generation

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

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

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

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

## *Existing Renewable Resources*

Currently, renewable energy facilities provide approximately 3,335 MW of firm and non-firm generation capacity, which represents 5.5 percent of Florida’s overall generation capacity of 60,703 MW in 2018. Table 6 summarizes the contribution by renewable type of Florida’s existing renewable energy sources.

**Table 6: State of Florida - Existing Renewable Resources**

| Renewable Type | MW | % Total |
|---|---|---|
| Solar | 1743 | 52.3% |
| Biomass | 469 | 14.1% |
| Municipal Solid Waste | 374 | 11.2% |
| Waste Heat | 310 | 9.3% |
| Wind* | 272 | 8.2% |
| Landfill Gas | 116 | 3.5% |
| Hydroelectric | 51 | 1.5% |
| **Renewable Total** | **3,335** | **100.00%** |

Source: FRCC 2019 Regional Load and Resource Plan & TYSP Utilities’ Data Responses
*Gulf’s wind resources are not present in-state.

Of the total 3,335 MW of renewable generation, approximately 2,018 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 fuel power plants. Solar generation contributes approximately 625 MW to this total, based upon the coincidence of solar generation and summer peak demand. Changes in timing of peak demand may influence the firm contributions of renewable resources such as solar and wind.

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

### *Non-Utility Renewable Generation*

Approximately 51 percent of Florida's existing renewable generation capacity comes from non-utility generators, of which municipal solid waste, biomass, and waste heat facilities make up the majority. In 1978, the US Congress enacted the Public Utility Regulatory Policies Act (PURPA). PURPA requires utilities to purchase electricity from cogeneration facilities and renewable energy power plants with a capacity no greater than 80 MW (collectively referred to as Qualifying Facilities or QFs). PURPA required utilities to buy electricity from QFs at the utility's full avoided cost. These costs are defined in Section 366.051, F.S., which provides in part that:

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

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

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

### *Customer-Owned Renewable Generation*

With respect to customer-owned renewable generation, Rule 25-6.065, F.A.C., requires the IOUs to offer net metering for all types of renewable generation up to 2 MW in capacity and a standard interconnection agreement with an expedited interconnection process. Net metering allows a customer, with renewable generation capability, to offset their energy usage. In 2008, the effective year of Rule 25-6.065, F.A.C., customer-owned renewable generation accounted for 3 MW of renewable capacity. As of year end 2018, approximately 317 MW of renewable capacity from nearly 38,000 systems has been installed statewide. Table 7 summarizes the growth of customer-owned renewable generation interconnections. Almost all installations are solar, with non-solar generation accounting for only 31 installations and 7.1 MW of installed capacity. The renewable generators in this category include wind turbines and anaerobic digesters.

**Table 7: State of Florida - Customer-Owned Renewable Growth**

| Year | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 |
|---|---|---|---|---|---|---|---|---|---|
| Number of Installations | 2,833 | 3,994 | 5,302 | 6,697 | 8,581 | 11,626 | 15,994 | 24,166 | 37,862 |
| Installed Capacity (MW) | 19.9 | 28.4 | 42.2 | 63.0 | 79.8 | 107.5 | 141 | 205 | 317 |

Source: Annual Utility Reports

## *Utility-Owned Renewable Generation*

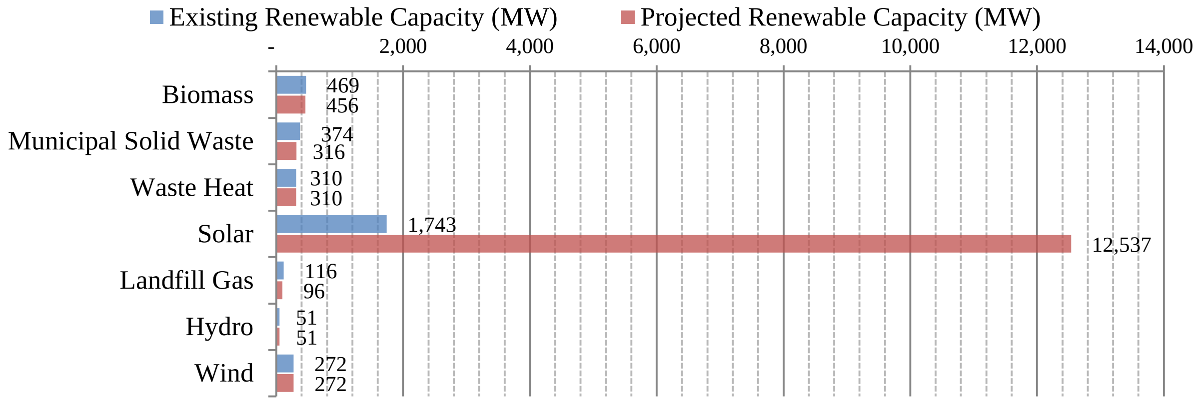
Utility-owned renewable generation also contributes to the state's total renewable capacity. The majority of this generation is from solar facilities. Due to the intermittent nature of solar resources, capacity from these facilities has previously been considered non-firm for planning purposes. However, several utilities are attributing firm capacity contributions to their solar installations based on the coincidence of solar generation and summer peak demand. Of the approximately 1,195 MW of existing utility-owned solar capacity, approximately 601 MW, or about 50 percent, is considered firm.

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

## *Planned Renewable Resources*

Florida's total renewable resources are expected to increase by an estimated 10,704 MW over the 10-year planning period, a significant increase from last year's estimated 7,049 MW projection. Figure 11 summarizes the existing and projected renewable capacity by generation type. Solar generation is projected to have the greatest increase over the planning horizon.

**Figure 11: State of Florida - Current and Projected Renewable Resources**[9]




Source: FRCC 2019 Regional Load and Resource Plan & TYSP Utilities' Data Responses

Of the 10,704 MW projected net increase in renewable capacity, firm resources contribute 4,434 MW, or about 41 percent, of the total. Solar generation alone contributes 4,056 MW of firm generation capability. For some existing renewable facilities, contracts for firm capacity are projected to expire within the 10-year planning horizon. If new contracts are signed in the future to replace those that expire, these resources will once again be included in the state's capacity mix to serve future demand. If these contracts are not extended, the renewable facilities could still deliver energy on an as-available basis.

As noted above, solar generation is anticipated to increase significantly over the 10-year period, with a total of 10,795 MW to be installed. This consists of 9,049 MW of utility-owned solar and 1,746 MW of contracted solar. In 2016, the Commission approved a settlement agreement entered into by FPL that included a provision for a Solar Base Rate Adjustment (SoBRA) mechanism.[10] The SoBRA mechanism details a process by which FPL may seek approval from the Commission to recover costs for solar projects brought into service that meet certain project cost and operational criteria. In 2017, the Commission approved settlement agreements entered into by DEF and TECO that also included provisions for similar SoBRA mechanisms.[11,12] As a result of their settlement agreements, FPL, DEF, and TECO are projecting solar capacity additions through SoBRA mechanisms totaling 1,200 MW, 700 MW, and 600 MW, respectively. The Commission has already approved 894 MW of FPL's SoBRA capacity, 344 MW of DEF's SoBRA capacity, and 405 MW of TECO's SoBRA capacity. FPL, DEF, and TECO are also projecting solar capacity additions throughout the remainder of the planning period outside of

[9] JEA's and Gulf's wind resources are not present in-state.

[10] Order No. PSC-16-0560-AS-EI, issued December 15, 2016, in Docket No. 20160021-EI, *In re: Petition for rate increase by Florida Power & Light Company.*

[11] Order No. PSC-2017-0451-AS-EU, issued November 20, 2017, in Docket No. 20170183-EI, *In re: Application for limited proceeding to approve 2017 second revised and restated settlement agreement, including certain rate adjustments, by Duke Energy Florida, LLC.*

[12] Order No. PSC-2017-0456-S-EI, issued November 27, 2017, in Docket No. 20170210-EI, *In re: Petition for limited proceeding to approve 2017 amended and restated stipulation and settlement agreement, by Tampa Electric Company.*

their respective SoBRA mechanisms. Table 8 provides an overview of the additional utility-scale (greater than 10 MW) solar capacity generation planned within the next 10 years.

**Table 8: TYSP Utilities - Planned Solar Installations**

| Year | Utility | Type | Capacity (MW) |
|---|---|---|---|
| 2019 | FPL | Utility Owned | 301 |
| | DEF | Utility Owned | 120 |
| | TECO | Utility Owned | 278 |
| | TAL | Purchased | 40 |
| | | **2019 Subtotal** | **739** |
| 2020 | FPL | Utility Owned | 745 |
| | DEF | Combined | 374 |
| | TECO | Utility Owned | 149 |
| | FMPA | Purchased | 149 |
| | JEA | Purchased | 50 |
| | OUC | Purchased | 112 |
| | | **2020 Subtotal** | **1,579** |
| 2021 | FPL | Utility Owned | 450 |
| | DEF | Combined | 355 |
| | TECO | Utility Owned | 53 |
| | JEA | Purchased | 200 |
| | | **2021 Subtotal** | **1,057** |
| 2022 | FPL | Utility Owned | 900 |
| | DEF | Combined | 300 |
| | SEC | Purchased | 40 |
| | | **2022 Subtotal** | **1,240** |
| 2023 | FPL | Utility Owned | 900 |
| | DEF | Combined | 225 |
| | | **2023 Subtotal** | **1,125** |
| 2024 | FPL | Utility Owned | 750 |
| | DEF | Combined | 225 |
| | | **2024 Subtotal** | **975** |
| 2025 | FPL | Utility Owned | 1,050 |
| | DEF | Combined | 225 |
| | | **2025 Subtotal** | **1,275** |
| 2026 | DEF | Combined | 150 |
| | | **2026 Subtotal** | **150** |
| 2027 | FPL | Utility Owned | 900 |
| | DEF | Combined | 150 |
| | | **2027 Subtotal** | **1,050** |
| 2028 | FPL | Utility Owned | 1,200 |
| | DEF | Combined | 150 |
| | | **2028 Subtotal** | **1,350** |
| TBD | DEF | Purchased | 250 |
| | | **TBD Subtotal** | **250** |
| | | **Total Installations** | **10,790** |

Source: FRCC 2019 Regional Load and Resource Plan & TYSP Utilities' Data Responses

## *Renewable Outlook*

Florida's renewable generation is projected to increase over the planning period. A significant portion of this increase can be attributed to growth in solar PV generation. As a result of the operational characteristics of these installations, namely the coincidence of solar generation and summer peak demand, some utilities are reporting a fraction of the nameplate capacity of these installations as firm resources for reliability considerations.

## *Energy Storage Outlook*

In addition to a number of electric grid related applications, emerging energy storage technologies have the potential to considerably increase not only the firm capacity contributions from solar PV installations, but their overall functionality as well. Energy storage technologies currently being researched include pumped hydropower, flywheels, compressed air, thermal storage, and battery storage. Of these technologies, Lithium ion (Li-ion) battery storage is being extensively researched due to its declining costs, operational characteristics, scalability, and siting flexibility.

The Commission has approved rate case settlement agreements from several utilities that include battery storage pilot programs. FPL is deploying 50 MW of batteries through 2020 as part of its 2016 settlement.[13] DEF also plans to implement 50 MW of batteries through 2022 as part of its 2017 settlement.[14]

In the 2019 Ten-Year Site Plans, firm storage capacity is being proposed for inclusion in resource planning for the first time. All of the proposed capacity consists of Li-ion battery storage, totaling over 500 MW.

FPL has proposed adding 469 MW of battery storage in late 2021 or early 2022. Approximately 409 MW of this capacity will be located in Manatee County and will partially offset the loss of generation from the retirement of Manatee Units 1 & 2. FPL expects that the battery will, in part, be charged by solar energy. In addition, FPL plans five pilot projects totaling 28 MW. The batteries being deployed in these projects will expand the number of storage applications and configurations that FPL will be able to test, as well as making the scale of deployment more meaningful, given the large size of FPL's system.

DEF has announced three Li-ion battery storage projects, totaling 22 MW. These projects consist of an 11 MW facility in Gilchrist County, a 5.5 MW facility in Gulf County, and a 5.5 MW in Hamilton County. DEF intends to complete the three projects by the end of 2020. DEF stated these facilities will enhance grid operations, increase efficiencies, improve overall reliability, and provide backup generation during outages.

TECO is installing a 12.6 MW Li-ion storage system at its Big Bend Solar site in Hillsborough County in 2019. This facility will be interconnected with the solar array and will add 5.6 MW of

[13]Order No. PSC-16-0560-AS-EI, issued December 15, 2016, in Docket No. 20160021-EI, *In re: Petition for rate increase by Florida Power & Light Company.*

[14]Order No. PSC-2017-0451-AS-EU, issued November 20, 2017, in Docket No. 20170183-EI, *In re: Application for limited proceeding to approve 2017 second revised and restated settlement agreement, including certain rate adjustments, by Duke Energy Florida, LLC.*

firm capacity. The expected project benefits include firming of the solar output during peak times and contribution to contingency reserves. TECO will continue to analyze storage technology and its applications with the objective to integrate these resources into their portfolio.

If current market trends in battery technology continue, Florida can expect battery storage capacity to increase over the planning period. Staff will continue to review and observe developments in this field.

# Traditional Generation

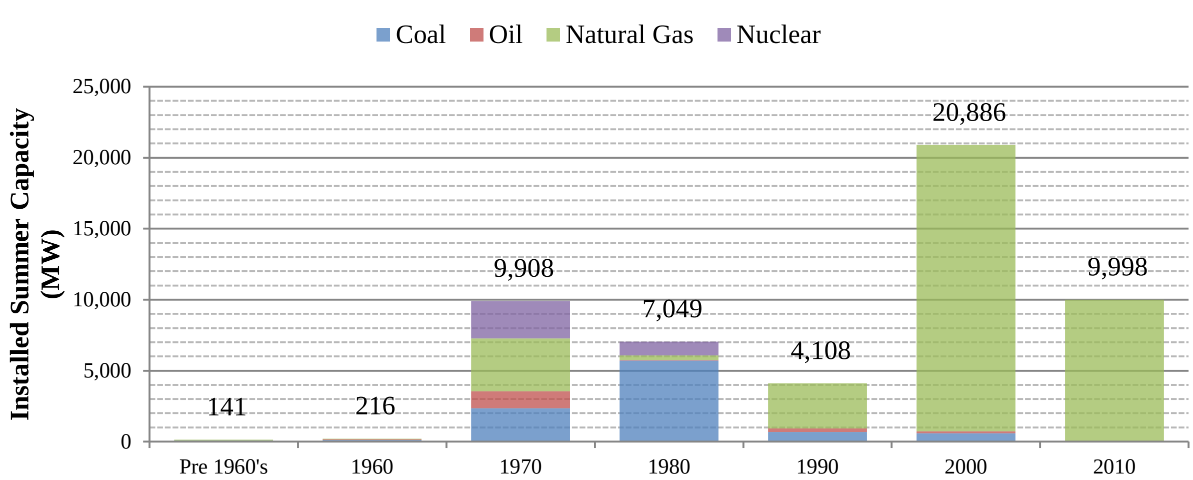
While renewable generation increases its contribution to the state's generating capacity, a majority of generation is projected to come from traditional sources, such as fossil-fueled steam and combustion turbine generators that have been added to Florida's electric grid over the last several decades.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

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

## *Existing Generation*

Florida's generating fleet includes incremental new additions to a historic base fleet, with units retiring as they become uneconomical to operate or maintain. Currently, Florida's existing capacity ranges greatly in age and fuel type, and legacy investments continue. The weighted average age of Florida's generating units is 22 years. While the original commercial in-service date may be in excess of 60 years for some units, they are constantly maintained as necessary in order to ensure safe and reliable operation, including uprates from existing capacity, which may have been added after the original in-service date. Figure 12 illustrates the decade current operating generating capacity was originally added to the grid, with the largest additions occurring in the 2000s.

**Figure 12: State of Florida - Electric Utility Installed Capacity by Decade**




Source: FRCC 2019 Regional Load and Resource Plan

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

## *Impact of EPA Rules*

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

- Carbon Pollution Emissions Standards for New, Modified and Reconstructed Secondary Sources: Electric Utility Generating Units - Sets carbon dioxide emissions limits for new, modified or reconstructed electric generators. These limits vary by type of fuel (coal or natural gas). New units are those built after January 18, 2014. Units that undergo modifications or reconstructions after June 18, 2014, that materially alter their air emissions are subject to the specified limits. This rule is currently under appeal. On August 21, 2018, as part of its proposed Affordable Clean Energy Rule, the EPA proposed updates to the New Source Review permitting program that may impact utility decisions regarding power plant modifications and reconstruction. No final actions have been taken. These recent regulatory developments will be addressed in a subsequent Ten-Year Site Plan review.

- Carbon Pollution Emission Guideline for Existing Electric Generating Units: On July 8, 2019, EPA finalized the Affordable Clean Energy (ACE) rule. ACE establishes carbon emission guidelines such that each state must perform site-specific reviews to determine the applicable standard of performance using EPA's best system of emission reduction (BSER). The BSER identifies six technologies upgrades as well as operation and maintenance practices directed at improving the heat rate efficiency of coal-fired steam generating units greater than 25 MWs that began construction on or before January 8, 2014. No other type of existing fossil steam utility generators are subject to the requirements of ACE.

- Prevention of Significant Deterioration and Nonattachment New Source Review: On August 1, 2019, EPA announced a proposed rule that would revise certain New Source Review (NSR) applicability regulation to clarify the requirements that apply to new sources, such as electric steam generators, proposing to undertake a physical or operational change (i.e., project) under the NSR preconstruction permitting program. EPA is proposing to clarify that both emission increases and decreases resulting from a given project are to be considered when determining whether the project by itself results in a significant emission increase.

- Mercury and Air Toxics Standards (MATS) - Sets limits for air emissions from existing and new coal- and oil-fired electric generators with a capacity greater than 25 megawatts. Covered emissions include: mercury and other metals, acid gases, and organic air toxics for all generators, as well as particulate matter, sulfur dioxide, and nitrogen oxide from new and modified coal and oil units.

- Cross-State Air Pollution Rule (CSAPR) - Requires certain states to reduce air emissions that contribute to ozone and/or fine particulate pollution in other states. The rule applies to all fossil-fueled (i.e., coal, oil, and natural gas) electric generators with a capacity over 25 megawatts within the upwind states. Originally, the Rule included Florida, however, the final Rule, issued September 7, 2016, removes North Carolina, South Carolina, and Florida from the program because modeling for the final Rule indicates that these states do not contribute significantly to ozone air quality problems in downwind states.

- Cooling Water Intake Structures (CWIS) - Sets impingement standards to reduce harm to aquatic wildlife pinned against cooling water intake structures at electric generating facilities. All electric generators that use state or federal waters for cooling with an intake velocity of at least two million gallons per day must meet impingement standards. Generating units with higher intake velocity may have additional requirements to reduce the damage to aquatic wildlife due to entrapment in the cooling water system.

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

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

### *Modernization and Efficiency Improvements*

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

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

Utilities also plan several efficiency improvements to existing generating units. For example, the conversion of existing simple cycle combustion turbines into a combined cycle unit, which captures the waste heat and uses it to generate additional electricity using a steam turbine. TECO is modernizing its Big Bend Power Station through the conversion of Big Bend Unit 1, along with two planned combustion turbines, into a 2x1 combined cycle unit by 2023. Per the Florida Department of Environmental Protection, this conversion does not require a determination of need by the Commission. FPL plans on upgrading its existing combined cycle fleet by improving the performance of the integrated combustion turbines at many of its current and planned power plants.

## *Planned Retirements*

Power plant retirements occur when the electric utility is unable to economically operate or maintain a generating unit due to environmental, economic, or technical concerns. Table 9 lists the 3,567 MW of existing generation that is scheduled to be retired during the planning period. 13 natural gas units totaling 1,871 MW, 4 coal units totaling 1,169 MW, and 12 oil units totaling 527 MW are set to retire within the next 10 years. Notably, TECO plans to retire its coal-fired Big Bend Unit 2 in 2021 and convert its coal-fired Big Bend Unit 1 steam turbine into a natural gas-fired combined cycle unit by 2023 as part of its Big Bend Power Station modernization.

**Table 9: State of Florida - Electric Generating Units to be Retired**

| Year | Utility Name | Plant Name & Unit Number | Unit Type | Net Capacity (MW) Summer |
|---|---|---|---|---|
| 2020 | DEF | Avon Park 1 | NG – CT | 24 |
| | DEF | Avon Park 2 | DFO – GT | 24 |
| | DEF | Higgins P1 – P4 | NG – CT | 107 |
| | | | **2020 Subtotal** | **155** |
| 2021 | FPL | Manatee 1 & 2 | NG – ST | 1,618 |
| | TECO | Big Bend 2 | BIT – ST | 385 |
| | | | **2021 Subtotal** | **2,003** |
| 2022 | GRU | Deerhaven FS01 | NG – ST | 75 |
| | | | **2022 Subtotal** | **75** |
| 2023 | SEC | Seminole Generating Station 1 or 2* | BIT – ST | 634 |
| | | | **2023 Subtotal** | **634** |
| 2024 | GPC | Crist 4 | BIT – ST | 75 |
| | | | **2024 Subtotal** | **75** |
| 2025 | DEF | Bayboro P1 – P4 | DFO – GT | 172 |
| | GPC | Pea Ridge 1 - 3 | NG – CT | 12 |
| | | | **2025 Subtotal** | **184** |
| 2026 | GRU | Deerhaven GT01 & GT02 | NG – GT | 35 |
| | GPC | Crist 5 | BIT – ST | 75 |
| | | | **2026 Subtotal** | **110** |
| 2027 | DEF | Debary P2 – P6 | DFO – GT | 249 |
| | DEF | Bartow P1 & P3 | DFO – GT | 82 |
| | | | **2027 Subtotal** | **331** |
| | | | **Total Retirements** | **3,567** |

* SEC has not determined whether to retire SGS 1 (626 MW) or SGS 2 (634 MW) at this time.

Source: 2019 Ten-Year Site Plans

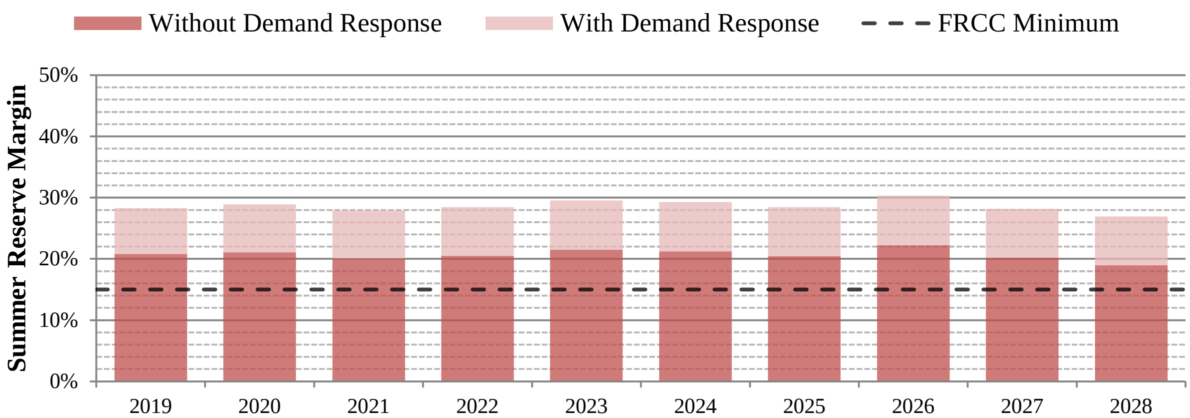
## *Reliability Requirements*

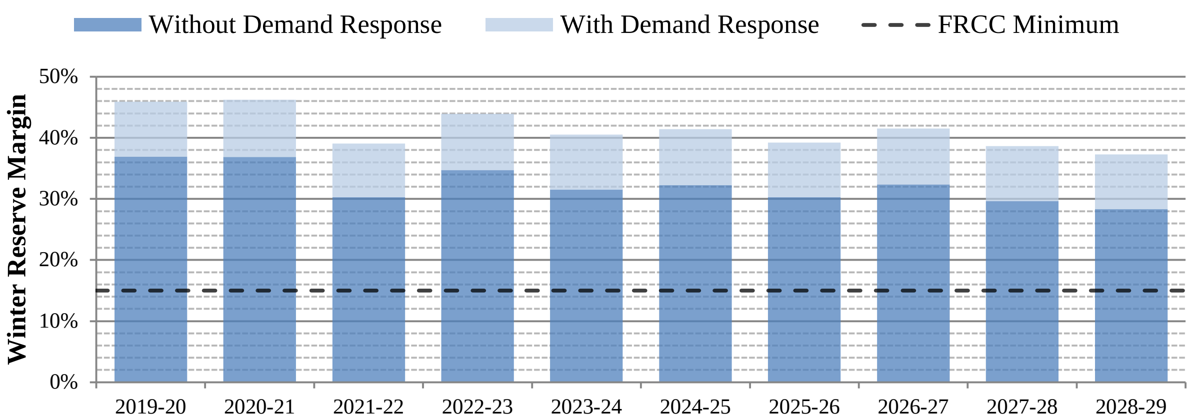
Florida's electric utilities are expected to have enough generating assets available at the time of peak demand to meet forecasted customer demand. If utilities only had sufficient generating capacity to meet forecasted peak demand, then potential instabilities could occur if customer demand exceeds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

On July 1, 2019, the SERC Reliability Corporation (SERC) became the new Compliance Enforcement Authority for all electric utilities previously registered with the FRCC. Electric utilities within Florida must maintain a minimum reserve margin of 15 percent for planning purposes. Certain utilities have elected to have a higher reserve margin, either on an annual or seasonal basis. The three largest reporting electric utilities, FPL, DEF, and TECO, are party to a stipulation approved by the Commission that utilizes a 20 percent reserve margin for planning.

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

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




Source: FRCC 2019 Regional Load and Resource Plan

## Role of Demand Response in Reserve Margin

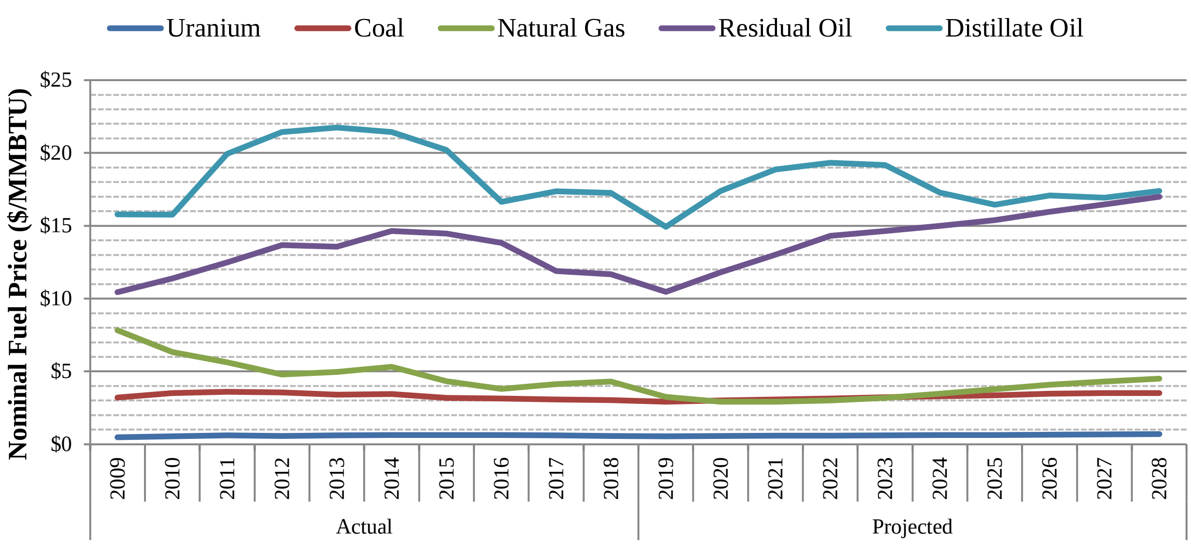
The Commission also considers the planning reserve margin without demand response. As illustrated above in Figure 13, the statewide seasonal reserve margin exceeds the FRCC's required 15 percent planning reserve margin without activation of demand response. Demand response activation increases the reserve margin in summer by 7.9 percent on average.

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

## *Fuel Price Forecast*

Fuel price is an important economic factor affecting the dispatch of the existing generating fleet and the selection of new generating units. In general, the capital cost of a power plant is inversely proportional to the cost of the fuel used to generate electricity from that unit. The major fuels consumed by Florida's electric utilities are natural gas, coal, and uranium. Distillate oil also factor into Florida utilities' fuel mix, albeit minimally compared to historical levels. Figure 14 below illustrates the weighted average fuel price history and forecasts for the reporting electric utilities. Fuel oil remains the most expensive fuel and suitable for backup and peaking purposes only.

**Figure 144: TYSP Utilities - Average Fuel Price of Reporting Electric Utilities**




Source: Utilities Responses to FPSC Staff Data Requests – 2019 TYSP Review

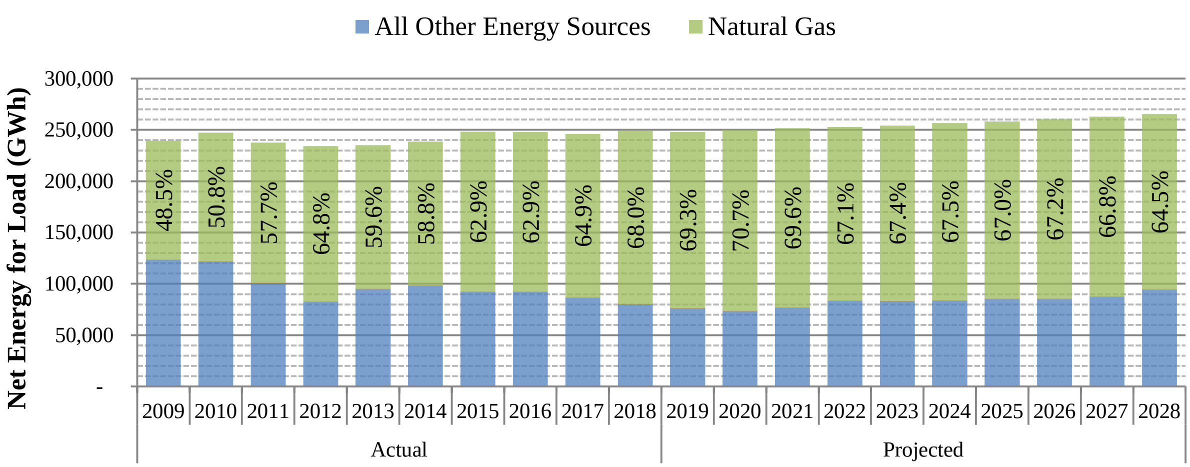
From 2003 to 2005, the price of natural gas was substantially higher than utilities had forecast. This led to concerns regarding escalating customer bills and an expectation that natural gas prices would remain high. As a result, Florida's electric utilities began making plans to build coal-fired units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

As shown in Figure 14 above, the price of natural gas declined precipitously after the financial crisis of 2008, and is forecasted to remain well below pre-2009 levels. Broad application of hydraulic fracturing and resource recovery techniques played a major role in lowering the price of natural gas. The smaller price differential between coal and natural gas, and the higher efficiency of natural gas combined cycle units has shifted the order of generation dispatch, with natural gas units displacing many of Florida utilities' coal units.

## *Fuel Diversity*

Natural gas has risen to become the dominant fuel in Florida within the last 10 years, displacing coal, and since 2010 has generated more net energy for load than all other fuels combined. As Figure 15 illustrates, natural gas was the source of approximately 68 percent of electric energy consumed in Florida in 2018. Natural gas consumption is anticipated to remain somewhat steady throughout the remainder of the planning period.

**Figure 15: State of Florida - Natural Gas Contribution to Energy Consumption**

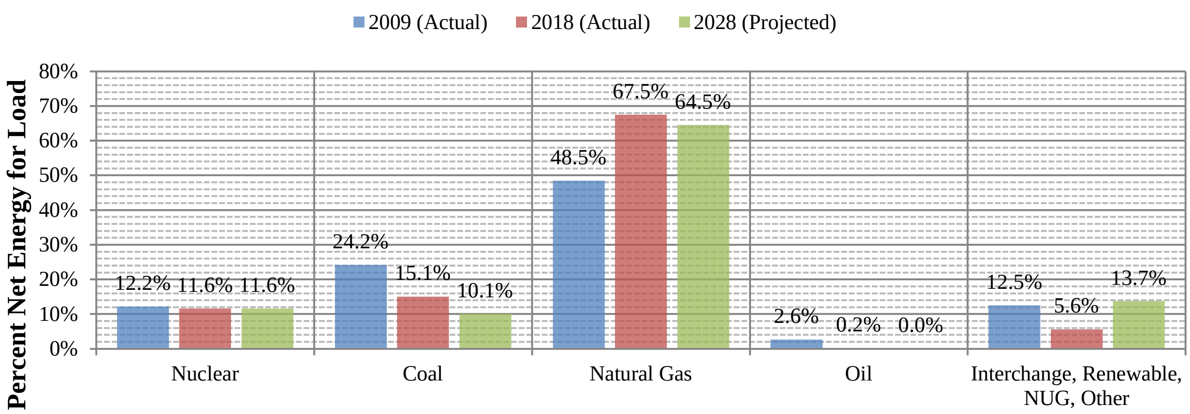



Source: FRCC 2010-2019 Regional Load and Resource Plan

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

Figure 16 shows Florida's historic and forecast percent net energy for load by fuel type for the actual years 2009 and 2018, and forecast year 2028. Oil has declined significantly, with its uses reduced to start-up fuel, peaking, and back-up for dual-fuel units in case of a fuel outage. Nuclear generation was reduced beginning in 2010 by the outage and eventual retirement of Crystal River 3 and extended outages for uprates at FPL's St. Lucie and Turkey Point power plants. The resulting capacity leaves Florida's contribution from nuclear approximately the same even with the loss of one of five nuclear units. Coal generation is expected to continue its downward trend well into the planning period. Natural gas has been the primary fuel used to meet the growth of energy consumption, and this trend is anticipated to continue throughout the planning period.

**Figure 16: State of Florida - Historic and Forecast Fuel Consumption**




Source: FRCC 2010-2019 Regional Load and Resource Plan

Based on 2017 Energy Information Administration (EIA) data, Florida ranks fourth in terms of the total volume of natural gas consumed compared to the rest of the United States.[15] For volume of natural gas consumed for electric generation, Florida ranks second, behind Texas. Florida's percentage of natural gas consumption for electric generation is the highest in the country, with 86 percent of all natural gas consumed in the state for electricity. Natural gas is not used as a heating fuel in most of Florida's homes and businesses, which rely instead upon electricity that is increasingly being generated by natural gas. As Florida has very little natural gas production and limited gas storage capacity, the state is reliant upon out-of-state production and storage to satisfy the growing electric demands of the state.

[15] U.S. Energy Information Administration natural gas consumption by end use annual report.

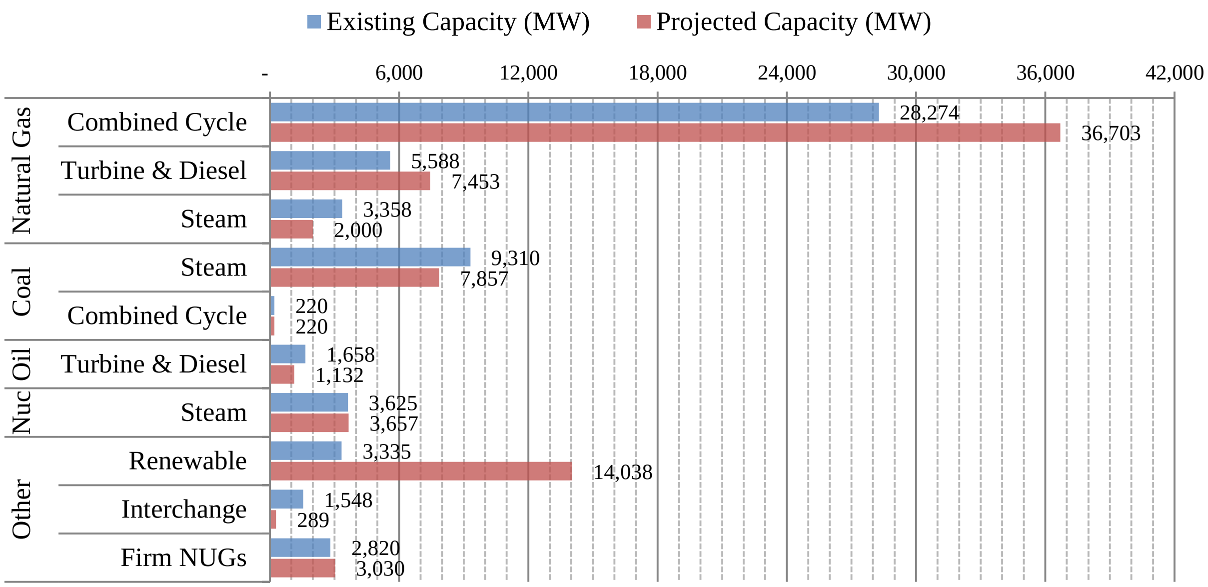
### *New Generation Planned*

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

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

Figure 17 illustrates the present and future aggregate capacity mix. The capacity values in Figure 17 incorporate all proposed additions, changes, and retirements contained in the reporting utilities' 2019 Ten-Year Site Plans and the FRCC's 2019 Regional Load and Resource Plan.

**Figure 17: State of Florida - Current and Projected Installed Capacity by Fuel**




Source: FRCC 2019 Regional Load and Resource Plan & TYSP Utilities' Data Responses

## *New Power Plants by Fuel Type*

### Nuclear

Nuclear capacity, while an alternative to natural gas-fired generation, is capital-intensive and requires a long lead time to construct. In April of 2018, FPL received Combined Operating Licenses (COL) from the Nuclear Regulatory Commission (NRC) for two future nuclear units, Turkey Point Units 6 & 7. These units are planned to be sited at FPL's Turkey Point site, the location of two existing nuclear generating units. The earliest possible in service date for these two units are outside the scope of the TYSP. FPL has two nuclear projects at Turkey Point that have minimal uprates planned during the projection period. FPL had previously uprated its existing four nuclear generating units, with the last uprate completed in early 2013.

### Natural Gas

Excluding renewables and minor nuclear and coal generation uprates, all remaining new power plants are natural gas-fired combustion turbines, internal combustion units, or combined cycle units. Combustion turbines run in simple cycle mode as peaking units represent the third most abundant type of generating capacity, behind only coal-fired steam generation. As combustion turbines are not a form of steam generation, unless part of a combined cycle unit, they do not require siting under the Power Plant Siting Act. Table 10 summarizes the approximately 8,291 MW of proposed new natural gas-fired generation included in the 2019 Ten-Year Site Plans.

**Table 10: State of Florida - Planned Natural Gas Units**

| In-Service Year | Utility Name | Plant Name & Unit Number | Net Capacity (MW) | Notes |
|---|---|---|---|---|
| **Previously Approved New Units** | | | | |
| 2019 | FPL | Okeechobee Energy Center | 1,778 | Docket No. 20150196-EI |
| 2022 | FPL | Dania Beach Energy Center | 1,163 | Docket No. 20170225-EI |
| 2022 | SEC | Seminole CC Facility | 1,108 | Docket No. 20170266-EI |
| | | | **Subtotal** | **4,049** |
| **New Units Requiring PPSA Approval** | | | | |
| 2024 | GPC | Combined Cycle 2 | 595 | |
| 2026 | FPL | Unsited CC Facility | 1,886 | |
| | | | **Subtotal** | **2,481** |
| **New Units Not Requiring PPSA Approval** | | | | |
| 2019 | TAL | Hopkins 1-4 | 74 | |
| 2020 | LAK | C.D. McIntosh 2 | 115 | |
| 2021 | TEC | Big Bend 5 & 6 | 660 | Convert to CC in 2023 |
| 2023 | TEC | Future CT 1 | 229 | |
| 2025 | TAL | Hopkins 5 | 18 | |
| 2026 | TEC | Future CT 2 | 229 | |
| 2027 | DEF | Unknown 1 & 2 | 436 | |
| | | | **Subtotal** | **1,761** |
| | | | **Total Planned Natural Gas Capacity** | **8,291** |

Source: 2019 Ten-Year Site Plans

## *Commission's Authority Over Siting*

Any proposed steam or solar generating unit greater than 75 MW requires a certification under the Electrical Power Plant Siting Act (PPSA), contained in Sections 403.501 through 403.518, F.S. The Commission has been given exclusive jurisdiction to determine the need for new electric power plants through Section 403.519, F.S. Upon receipt of a determination of need, the electric utility would then seek approval from the Florida Department of Environmental Protection, which addresses land use and environmental concerns. Finally, the Governor and Cabinet, sitting as the Siting Board, ultimately must approve or deny the overall certification of a proposed power plant. As shown in Table 10, there is approximately 2,481 MW of generation that would require certification under the PPSA. Based on the unit type and projected in-service date, GPC may be filing a need determination sometime in 2020 and FPL may be filing a need determination sometime in 2022.

## *Transmission*

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

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

Table 11 lists all proposed transmission lines in the 2019 Ten-Year Site Plans and the FRCC 2019 Regional Load and Resource Plan that require TLSA certification. All planned lines have already received the approval of the Commission, either independently or as part of a PPSA determination of need.

**Table 11: State of Florida - Planned Transmission Lines**

| Utility | Transmission Line | Line Length (Miles) | Nominal Voltage (kV) | Date Need Approved | Date TLSA Certified | In-Service Date |
|---|---|---|---|---|---|---|
| FPL | Levee-Midway | 150 | 500 | 05/28/1988 | 04/20/1990 | 06/01/2019 |
| TECO | Thonotosassa Wheeler | 8 | 230 | 06/21/2007 | 08/07/2008 | TBD |
| TECO | Wheeler to Willow Oak | 17 | 230 | 06/21/2007 | 08/07/2008 | TBD |

Source: 2019 Ten-Year Site Plans & FRCC 2019 Regional Load and Resource Plan

# Utility Perspectives

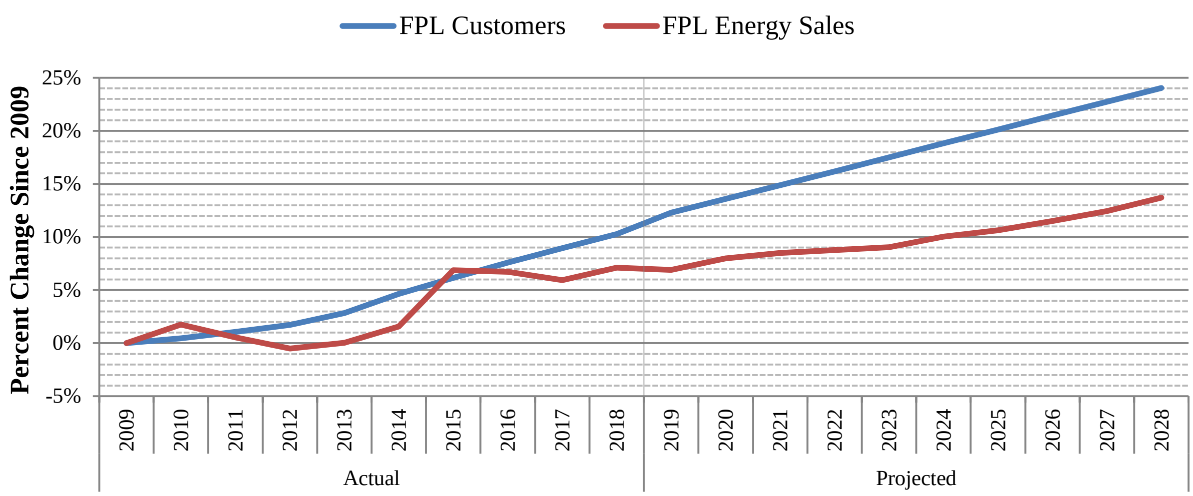
# Florida Power & Light Company (FPL)

FPL is an investor-owned utility and Florida's largest electric utility. The Utility's service territory is within the FRCC region and is primarily in south Florida and along the east coast. As an investor-owned utility, the Commission has regulatory authority over all aspects of FPL's operations, including rates, reliability, and safety. Pursuant to Section 186.801(2), F.S., the Commission finds FPL's 2019 Ten-Year Site Plan suitable for planning purposes.

## Load and Energy Forecasts

In 2018, FPL had approximately 4,961,330 customers and annual retail energy sales of 110,053 GWh or approximately 47.8 percent of Florida's annual retail energy sales. Figure 18 illustrates the Utility's historic and forecast number of customers and retail energy sales, in terms of percentage growth from 2009. Over the past 10 years, FPL's customer base has increased by 10.27 percent, while retail sales have grown by 7.10 percent. As illustrated, FPL's retail energy sales are anticipated to exceed its historic 2015 peak in 2019.

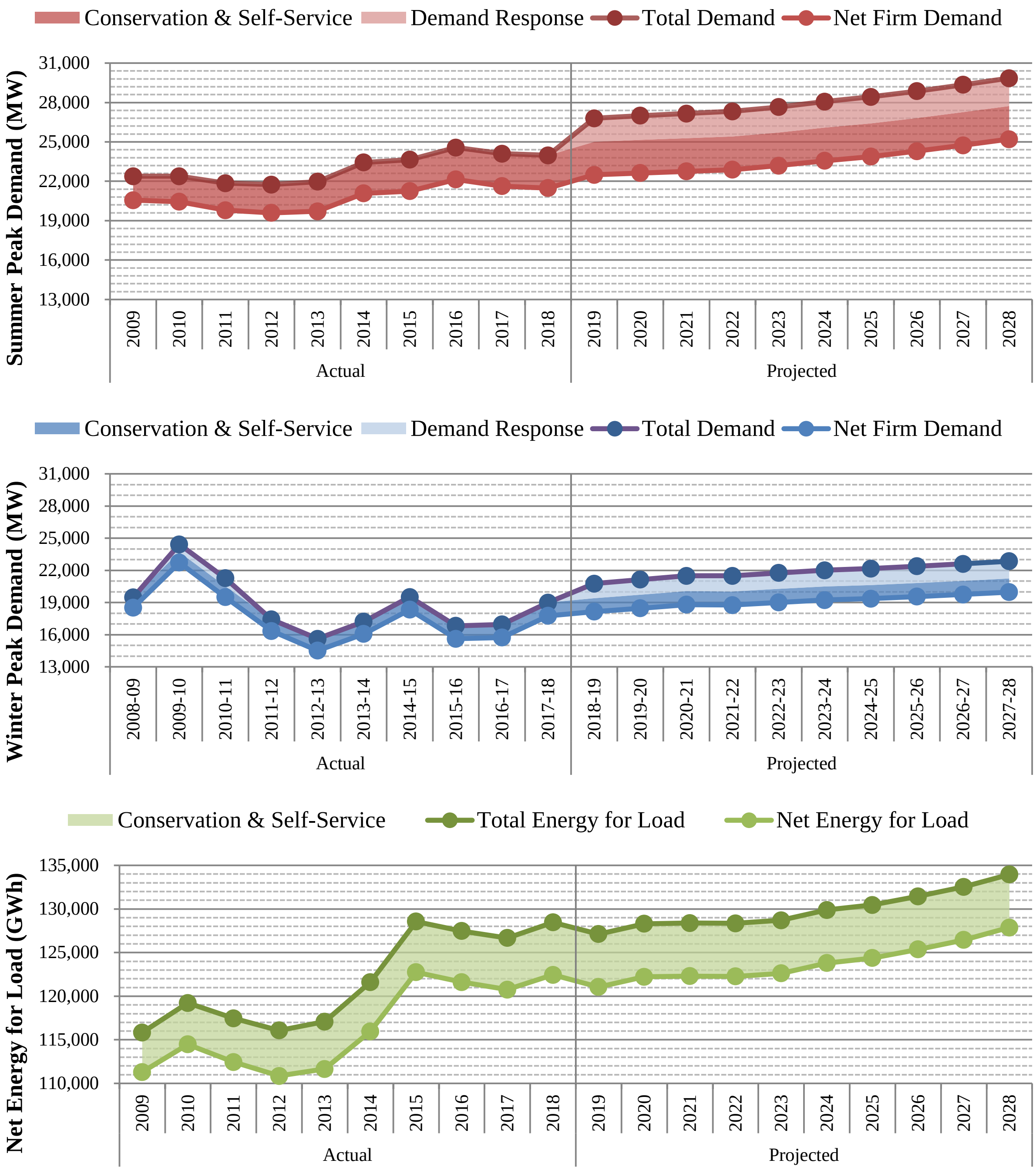
**Figure 18: FPL Growth**




Source: 2019 Ten-Year Site Plan

The three graphs in Figure 19 show FPL's seasonal peak demand and net energy for load, for the historic years 2009 through 2018 and forecast years 2019 through 2028. These graphs include the impact of demand-side management, and for future years assume that all available demand response resources will be activated during the seasonal peak. Historically, demand response has not been activated during the seasonal peak demand, excluding the winters of 2009-10 and 2010-11. As an investor-owned utility, FPL is subject to FEECA and currently offers energy efficiency and demand response programs to customers to reduce peak demand and annual energy consumption. FPL is currently petitioning the Commission for approval of annual conservation goals for the period 2020 through 2029. The Utility's 2019 Ten-Year Site Plan reflects these proposed goals.

**Figure 19: FPL Demand and Energy Forecasts**




Source: 2019 Ten-Year Site Plan and Data Responses

## Fuel Diversity

Table 12 shows FPL's actual net energy for load by fuel type for 2018, and the projected fuel mix for 2028. FPL relies primarily upon natural gas and nuclear for energy generation, making up approximately 98 percent of net energy for load. FPL plans that renewable energy will provide over 14 percent of its generation by 2028. FPL is projected to have the second highest percentage of renewable energy generation in 2028 of the TYSP Utilities.

**Table 12: FPL Energy Consumption by Fuel Type**

| Fuel Type | Net Energy for Load | | | |
|---|---|---|---|---|
| | 2018 | | 2028 | |
| | GWh | % | GWh | % |
| **Natural Gas** | 91,213 | **74.5%** | 76,202 | **59.6%** |
| **Coal** | 2,586 | **2.1%** | 1,819 | **1.4%** |
| **Nuclear** | 28,176 | **23.0%** | 29,675 | **23.2%** |
| **Oil** | 377 | **0.3%** | 5 | **0.0%** |
| **Renewable** | 1,887 | **1.5%** | 18,609 | **14.5%** |
| **Interchange** | 0 | **0.0%** | 0 | **0.0%** |
| **Other** | -1,793 | **-1.5%** | 1,631 | **1.3%** |
| **Total** | **122,447** | | **127,941** | |

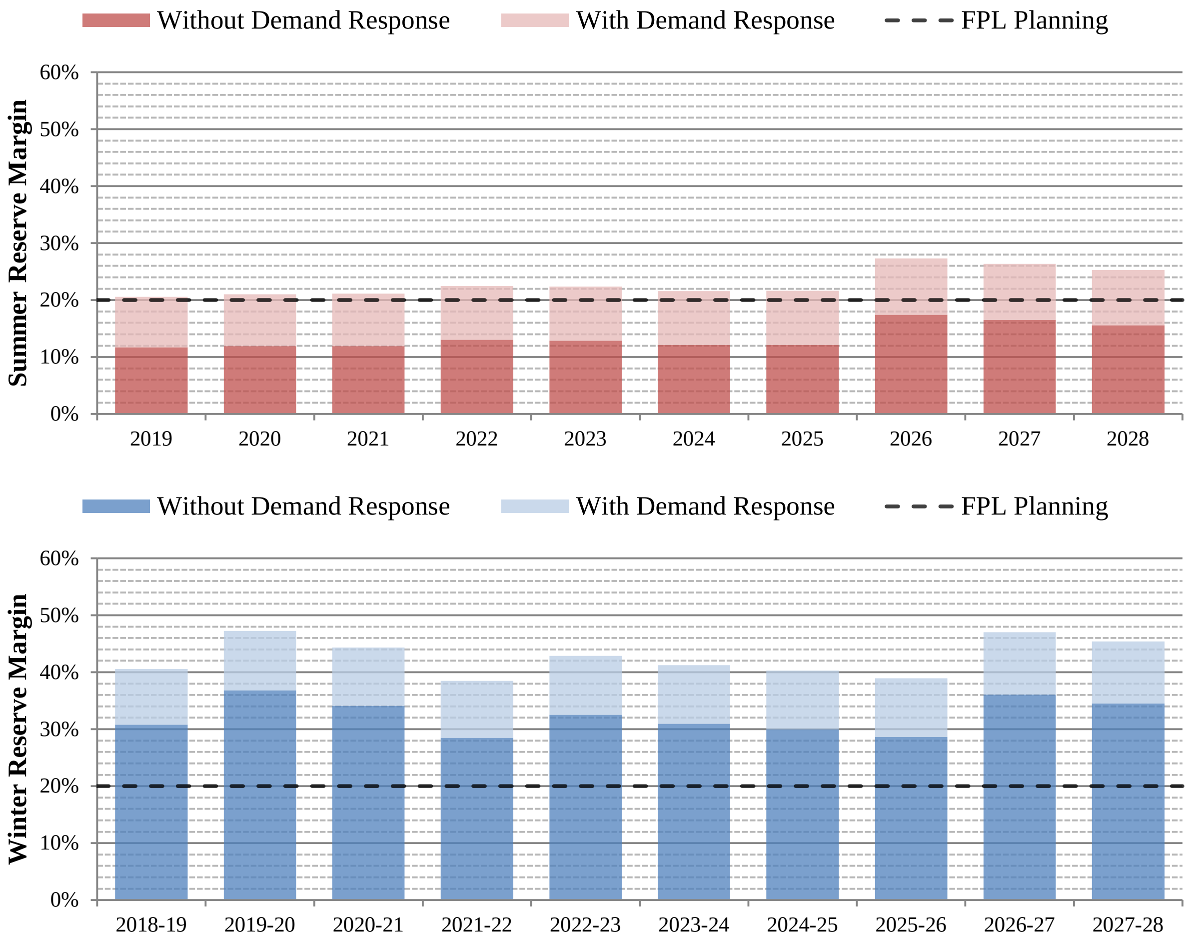
Source: 2019 Ten-Year Site Plan

## Reliability Requirements

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

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

**Figure 20: FPL Reserve Margin Forecast**




Source: 2019 Ten-Year Site Plan

In addition to LOLP and the reserve margin, FPL utilizes a third reliability criterion which it refers to as its 10 percent generation-only reserve margin. This criterion requires that available firm capacity be 10 percent greater than the sum of customer seasonal demand, without consideration of incremental energy efficiency and all existing and incremental demand response resources. Currently, no other utility utilizes this same metric. FPL's generation-only reserve margin is not the controlling factor for any planned unit additions. However, it does provide useful information regarding the assurance that the projected 20 percent reserve margin will be realized.

While FPL does not include incremental energy efficiency resources and cumulative demand response in its resource planning for the generation-only reserve margin criterion, the Utility would remain subject to FEECA and the conservation goals established by the Commission. FPL would continue paying rebates and other incentives to participants, which are collected from all ratepayers through the Energy Conservation Cost Recovery Clause, but would not consider the potential capacity reductions of any future participation in energy efficiency or demand response programs during the 10-year planning period for planning purposes only when using this reliability criterion.

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

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

## Generation Resources

FPL plans two unit retirements and multiple unit additions during the planning period, as described in Table 13. FPL plans to retire Manatee Units 1 & 2 in 2021 due to the significant annual capital and operation and maintenance (O&M) costs required to keep these relatively fuel-inefficient units operational. As FPL's generation system becomes more fuel-efficient, these units' already low capacity factors (approximately 11% in 2018) are projected to trend even lower in the coming years. Originally set for retirement in 2028, the 2021 retirement of these units is projected to save FPL customers approximately $101 million, net of projected generation and transmission costs needed to offset the loss of 1,618 MW of firm capacity.

The projected in-service dates of FPL's planned nuclear units are outside the 10-year planning period. On September 3, 2015, FPL filed a need determination with the Commission for the Okeechobee Clean Energy Center, a natural gas-fired combined cycle unit, which was granted on January 19, 2016.[16] The unit is expected to go into service in 2019. FPL filed another need determination with the Commission on October 20, 2017, this time for the Dania Beach Clean Energy Center, another natural gas-fired combined cycle unit, which was granted on March 19, 2018.[17] The unit is expected to be in-service by 2022.

FPL has included 7,152 MW of planned solar additions outside of the 894 MW of SoBRA additions approved in the Fuel and Purchased Power Cost Recovery Clause docket.[18,19] Another

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[16]Order No. PSC-16-0032-FOF-EI, issued January 19, 2016, in Docket No. 20150196-EI, *In re: Petition for determination of need for Okeechobee Clean Energy Center Unit 1, by Florida Power & Light Company.*
[17]Order No. PSC-2018-0150-FOF-EI, issued March 19, 2018, in Docket No. 20170225-EI, *In re: Petition for determination of need for Dania Beach Clean Energy Center Unit 7, by Florida Power & Light Company.*
[18]Order No. PSC-2018-0028-FOF-EI, issued January 8, 2018, in Docket No. 20180001-EI, *In re: Fuel and purchased power cost recovery clause with generating performance incentive factor.*
[19]Order No. PSC-2018-0610-FOF-EI, issued December 26, 2018, in Docket No. 20180001-EI, *In re: Fuel and purchased power cost recovery clause with generating performance incentive factor.*

298 MW of SoBRA additions are the subject of an active Commission docket.[20] The in-service dates of 447 MW and the construction of another 596 MW of non-SoBRA solar additions are dependent on the outcome of another active Commission docket regarding FPL's SolarTogether Program.[21] FPL plans to conduct further economic analysis before reaching a decision to proceed with these additions. All planned solar additions make up approximately 59 percent of FPL's planned future units.

FPL has proposed adding 469 MW of battery storage in late 2021 or early 2022. Approximately 409 MW of this capacity will be located in Manatee County and will partially offset the loss of generation from the retirement of Manatee Units 1 & 2. FPL expects that the battery will, in part, be charged by solar energy. In addition, FPL plans five pilot projects totaling 28 MW. The batteries being deployed in these projects will expand the number of storage applications and configurations that FPL will be able to test, as well as making the scale of deployment more meaningful, given the large size of FPL's system.

[20]Document No. 01342-2019, issued March 1, 2019, in Docket No. 20190001-EI, *In re: Fuel and purchased power cost recovery clause with generating performance incentive factor.*
[21]Document No. 03066-2019, issued March 13, 2019, in Docket No. 20190061-EI, *In re: Petition for approval of FPL SolarTogether program and tariff, by Florida Power & Light Company.*

## Table 13: FPL Generation Resource Changes

| Year | Plant Name & Unit Number | Unit Type | Net Capacity (MW) | Solar Firm Capacity (Summer) | Notes |
|---|---|---|---|---|---|
| | | | Sum | Sum | |
| **Retiring Units** | | | | | |
| 2021 | Manatee 1 & 2 | NG – ST | 1,618 | N/A | |
| **Total Retirements** | | | **1,618** | | |
| **New Units** | | | | | |
| 2019 | Interstate Solar Energy Center | PV | 75 | 41 | These SoBRA units received Commission approval in Docket No. 20180001-EI. |
| 2019 | Miami-Dade Solar | PV | 75 | 41 | |
| 2019 | Pioneer Trail Solar Energy Center | PV | 75 | 41 | |
| 2019 | Sunshine Gateway Solar | PV | 75 | 41 | |
| 2019 | Okeechobee Clean Energy Center | NG – CC | 1,778 | N/A | Docket No. 20150196-EI. |
| 2020 | Hibiscus | PV | 75 | 41 | These SoBRA units are the subject of an active Commission docket, Docket No. 20190001-EI. |
| 2020 | Southfork | PV | 75 | 41 | |
| 2020 | Echo River | PV | 75 | 41 | |
| 2020 | Okeechobee | PV | 75 | 41 | |
| 2020 | Northern Preserve | PV | 75 | 41 | These non-SoBRA units are the subject of an active Commission docket, Docket No. 20190061-EI. |
| 2020 | Twin Lakes | PV | 75 | 41 | |
| 2020 | Cattle Ranch | PV | 75 | 41 | |
| 2020 | Sweetbay | PV | 75 | 41 | |
| 2020 | Babcock Preserve | PV | 75 | 41 | |
| 2020 | Blue Heron | PV | 75 | 41 | |
| 2021 | Egret | PV | 75 | 41 | |
| 2021 | Lakeside | PV | 75 | 41 | |
| 2021 | Magnolia Springs | PV | 75 | 41 | |
| 2021 | Pelican | PV | 75 | 41 | |
| 2021 | Rodeo | PV | 75 | 41 | |
| 2021 | Discovery | PV | 75 | 41 | |
| 2021 | Manatee County Site | PV | 75 | 37 | |
| 2021 | Nassau | PV | 75 | 37 | |
| 2021 | Orange Blossom | PV | 75 | 37 | |
| 2021 | Palm Bay | PV | 75 | 37 | |
| 2021 | Putnam County Site | PV | 75 | 37 | |
| 2021 | Sabal Palm | PV | 75 | 37 | |
| 2021 | Trailside | PV | 75 | 37 | |
| 2021 | Union Springs | PV | 75 | 37 | |
| 2021/22 | Battery Storage | BS | 469 | N/A | |
| 2022 | Dania Beach Clean Energy Center | NG – CC | 1,163 | N/A | Docket No. 20170225-EI |
| 2022-28 | Unsited Solar | PV | 5,662 | 2,158 | |
| 2026 | Unsited Combined Cycle | NG – CC | 1,886 | N/A | |
| **Total New Units** | | | **13,044** | **3,275** | |
| **Percentage of Solar Units Planned of Total New Units** | | | **59%** | | |
| **Net Additions** | | | **11,426** | | |

Source: 2019 Ten-Year Site Plan

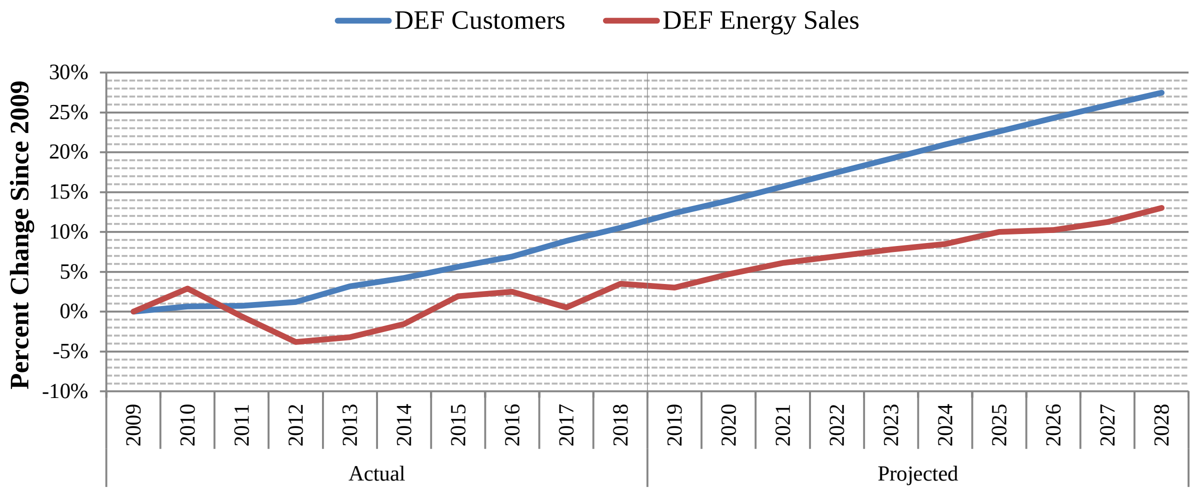
# Duke Energy Florida, LLC (DEF)

DEF is an investor-owned utility and Florida’s second largest electric utility. The Utility’s service territory is within the FRCC region and is primarily in central and west central Florida. As an investor-owned utility, the Commission has regulatory authority over all aspects of operations, including rates, reliability, and safety. Pursuant to Section 186.801(2), F.S., the Commission finds DEF’s 2019 Ten-Year Site Plan suitable for planning purposes.

## Load & Energy Forecasts

In 2018, DEF had approximately 1,801,564 customers and annual retail energy sales of 39,144 GWh or approximately 17.0 percent of Florida’s annual retail energy sales. Figure 21 illustrates the Utility’s historic and forecast number of customers and retail energy sales, in terms of percentage growth from 2009. Over the last 10 years, DEF’s customer base has increased by 10.51 percent, while retail sales have grown by 3.49 percent.

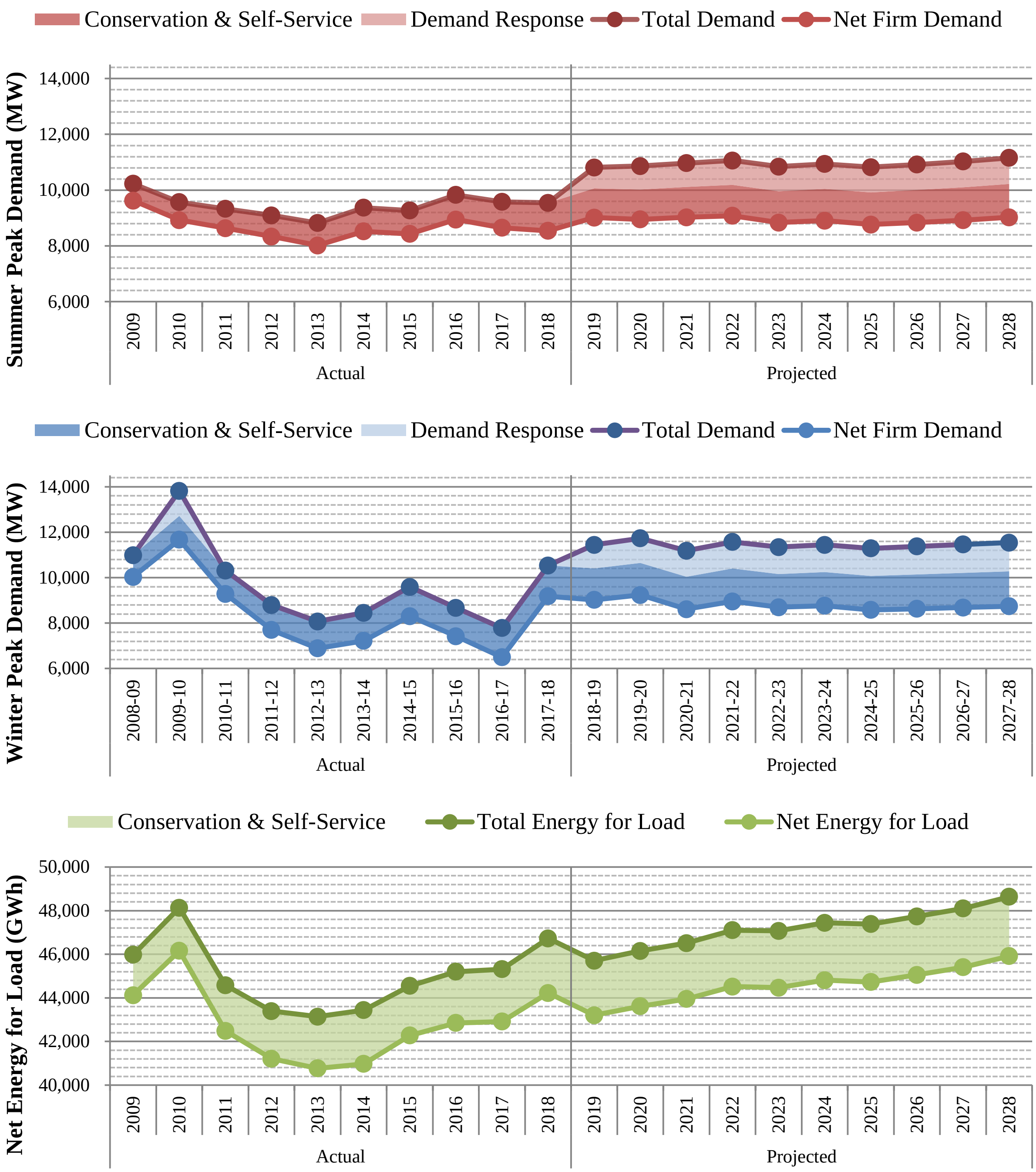
**Figure 21: DEF Growth**




Source: 2019 Ten-Year Site Plan

The three graphs in Figure 22 show DEF’s seasonal peak demand and net energy for load for the historic years of 2009 through 2018 and forecast years 2019 through 2028. These graphs include the full impact of demand-side management and assume that all available demand response resources will be activated during the seasonal peak. Historically, demand response has not been activated during seasonal peak demand, excluding extreme weather events. As an investor-owned utility, DEF is subject to FEECA, and currently offers energy efficiency and demand response programs to customers to reduce peak demand and annual energy consumption. The Utility’s 2019 Ten-Year Site Plan reflects the revised demand-side management goals established by the Commission in December 2014.

**Figure 22: DEF Demand and Energy Forecasts**




Source: 2019 Ten-Year Site Plan and Data Responses

## Fuel Diversity

Table 14 shows DEF's actual net energy for load by fuel type as of 2018 and the projected fuel mix for 2028. DEF relies primarily upon natural gas and coal for energy generation, making up approximately 84 percent of net energy for load. DEF plans to reduce coal usage over the planning period, and to increase renewable energy generation, making natural gas and renewable energy DEF's primary sources of generation by 2028. DEF projects the third highest percentage of renewable energy generation in 2028 of the TYSP Utilities.

**Table 14: DEF Energy Consumption by Fuel Type**

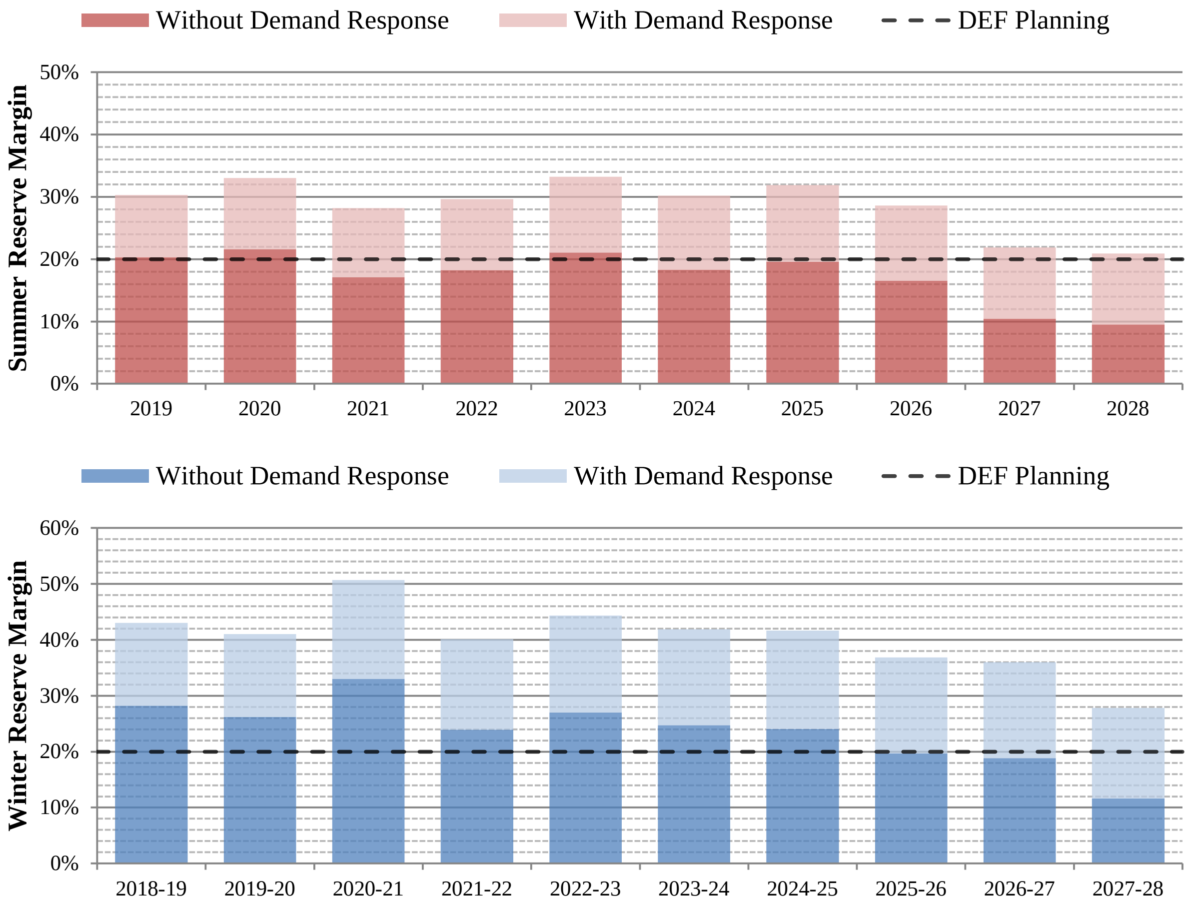
| Fuel Type | Net Energy for Load | | | |
|---|---|---|---|---|
| | 2018 | | 2028 | |
| | GWh | % | GWh | % |
| **Natural Gas** | 28,687 | **64.9%** | 35,377 | **77.0%** |
| **Coal** | 8,422 | **19.0%** | 3,930 | **8.6%** |
| **Nuclear** | 0 | **0.0%** | 0 | **0.0%** |
| **Oil** | 90 | **0.2%** | 63 | **0.1%** |
| **Renewable** | 1,270 | **2.9%** | 6,489 | **14.1%** |
| **Interchange** | 2,244 | **5.1%** | 56 | **0.1%** |
| **NUG & Other** | 3,511 | **7.9%** | 2 | **0.0%** |
| **Total** | **44,224** | | **45,917** | |

Source: 2019 Ten-Year Site Plan and Data Responses

## Reliability Requirements

Since 1999, DEF has utilized a 20 percent planning reserve margin criterion. Figure 23 displays the forecast planning reserve margin for DEF through the planning period for both seasons, with and without the use of demand response. As shown in the figure, DEF's generation needs are controlled by its summer peaking throughout the planning period.

**Figure 23: DEF Reserve Margin Forecast**




Source: 2019 Ten-Year Site Plan

## Generation Resources

DEF projects multiple unit retirements and additions during the planning period, as described in Table 15. DEF plans to retire several gas-fired units at multiple power plant sites. DEF's adding two combustion turbines at an undesignated site(s) in 2027.

DEF has included 750 MW of planned solar additions outside of the 344 MW of SoBRA additions approved by the Commission.[22,23] As a result of forecasts that show the continued reduction in the cost of solar PV technology, DEF has incorporated this energy source as a supply-side resource in both its near-term and long-term generation plans. The solar additions make up approximately 76 percent of DEF's planned future units.

DEF has announced three Li-ion battery storage projects, totaling 22 MW. These projects consist of an 11 MW facility in Gilchrist County, a 5.5 MW facility in Gulf County, and a 5.5 MW in

[22]Order No. PSC-2019-0159-FOF-EI, issued April 30, 2019, in Docket No. 20180149-EI, *In re: Petition for a limited proceeding to approve first solar base rate adjustment, by Duke Energy Florida, LLC.*
[23]Order No. PSC-2019-0292-FOF-EI, issued July 22, 2019, in Docket No. 20190072-EI, *In re: Petition for a limited proceeding to approve second solar base rate adjustment, by Duke Energy Florida, LLC.*

Hamilton County. DEF intends to complete the three projects by the end of 2020. DEF stated these facilities will enhance grid operations, increase efficiencies, improve overall reliability, and provide backup generation during outages.

**Table 15: DEF Generation Resource Changes**

| Year | Plant Name & Unit Number | Unit Type | Net Capacity (MW) Sum | Solar Firm Capacity (Summer) Sum | Notes |
|---|---|---|---|---|---|
| **Retiring Units** | | | | | |
| 2020 | Avon Park P1 | NG – CT | 24 | N/A | |
| 2020 | Avon Park P2 | DFO – GT | 24 | N/A | |
| 2020 | Higgins P1 – P4 | NG – CT | 107 | N/A | |
| 2025 | Bayboro P1 – P4 | DFO – GT | 172 | N/A | |
| 2027 | Debary P2 – P6 | DFO – GT | 249 | N/A | |
| 2027 | Bartow P1 & P3 | DFO – GT | 82 | N/A | |
| **Total Retirements** | | | **658** | | |
| **New Units** | | | | | |
| 2019 | St Petersburg Pier | PV | 0.4 | 0.4 | |
| 2019 | Trenton[1] | PV | 75 | 43 | These SoBRA units received Commission approval in Docket No. 20190072-EI. |
| 2019 | Lake Placid[1] | PV | 45 | 26 | |
| 2020 | Debray[1] | PV | 75 | 34 | |
| 2020 | Columbia[2] | PV | 75 | 43 | This SoBRA unit received Commission approval in Docket No. 20180149-EI. |
| 2020 | Solar 10 & 11 | PV | 150 | 85 | |
| 2021 | Solar 12 – 14 | PV | 205 | 117 | |
| 2022 | Solar 15 & 16 | PV | 150 | 85 | |
| 2023 | Solar 17 | PV | 75 | 43 | |
| 2024 | Solar 18 & 19 | PV | 150 | 85 | |
| 2025 | Solar 20 & 21 | PV | 150 | 85 | |
| 2026 | Solar 22 | PV | 75 | 43 | |
| 2027 | Unknown 1 & 2 | NG – CT | 436 | N/A | |
| 2027 | Solar 23 | PV | 75 | 43 | |
| 2028 | Solar 24 | PV | 75 | 43 | |
| **Total New Units** | | | **1,811** | **775** | |
| **Percentage of Solar Units Planned of Total New Units** | | | **76%** | | |
| **Net Additions** | | | **1,153** | | |

Source: 2019 Ten-Year Site Plan

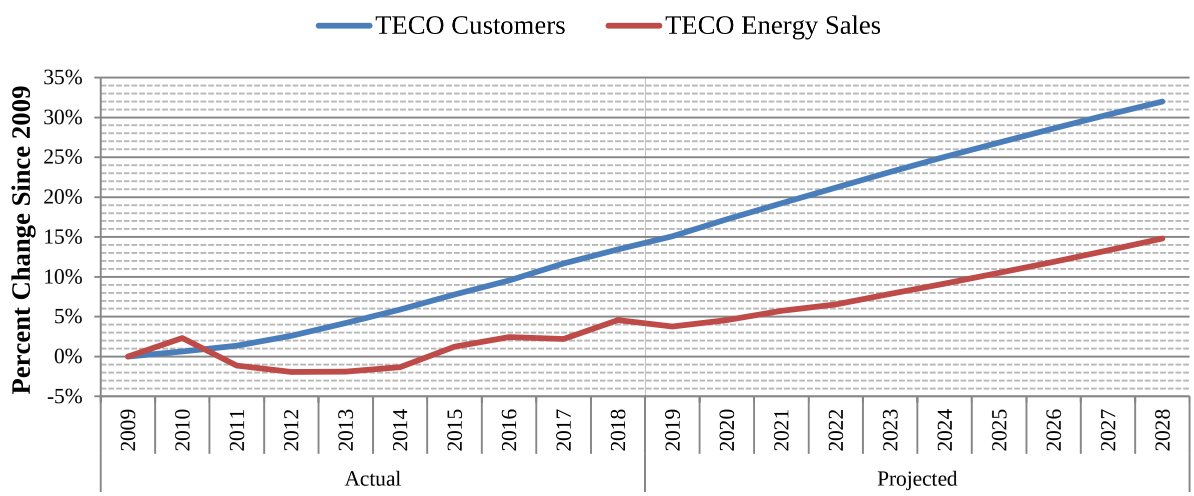
# Tampa Electric Company (TECO)

TECO is an investor-owned utility and Florida's third largest electric utility. The Utility's service territory is within the FRCC region and consists primarily of the Tampa metropolitan area. As an investor-owned utility, the Commission has regulatory authority over all aspects of operations, including rates, reliability, and safety. Pursuant to Section 186.801(2), F.S., the Commission finds TECO's 2019 Ten-Year Site Plan suitable for planning purposes.

## Load & Energy Forecasts

In 2018, TECO had approximately 756,254 customers and annual retail energy sales of 19,631 GWh or approximately 8.5 percent of Florida's annual retail energy sales. Figure 24 illustrates the Utility's historic and forecast number of customers and retail energy sales, in terms of percentage growth from 2009. Over the last 10 years, TECO's customer base has increased by 13.42 percent, while retail sales have increased by 4.56 percent.

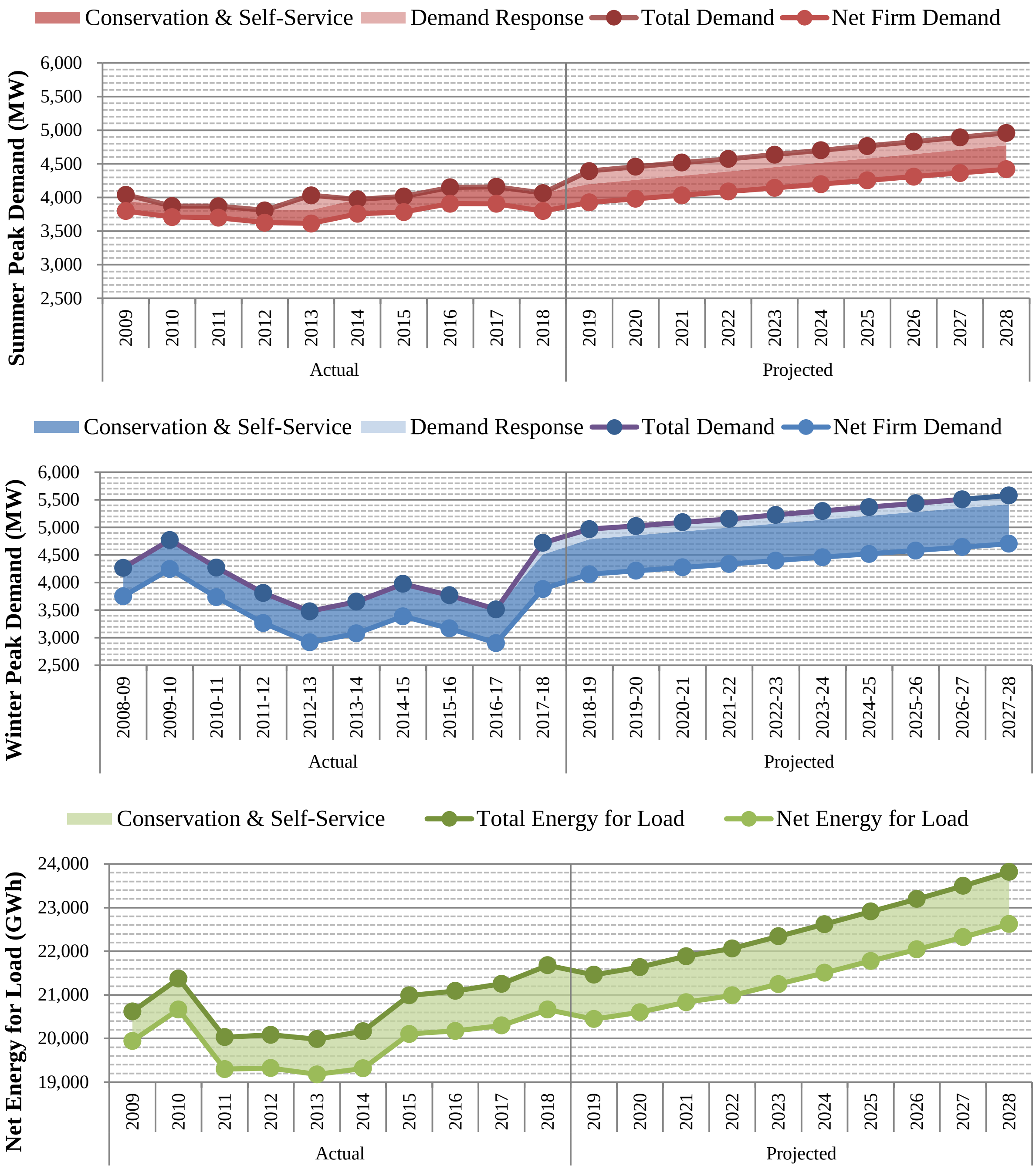
**Figure 24: TECO Growth**




Source: 2019 Ten-Year Site Plan

The three graphs in Figure 25 show TECO's seasonal peak demand and net energy for load for the historic years of 2009 through 2018 and forecast years 2019 through 2028. These graphs include the full impact of demand-side management, and assume that all available demand response resources will be activated during the seasonal peak. Historically, demand response has not been activated during seasonal peak demand excluding extreme weather events.

**Figure 25: TECO Demand and Energy Forecasts**




Source: 2019 Ten-Year Site Plan and Data Responses

As an investor-owned utility, TECO is subject to FEECA and currently offers energy efficiency and demand response programs to customers to reduce peak demand and annual energy consumption. The Utility's 2019 Ten-Year Site Plan reflects the revised demand-side management goals established by the Commission in December 2014.

## Fuel Diversity

Table 16 shows TECO's actual net energy for load by fuel type as of 2018 and the projected fuel mix for 2028. Based on its 2019 Ten-Year Site Plan, natural gas is used for the majority of TECO's energy generation. Natural gas accounts for approximately 78 percent of net energy for load. In the future, TECO projects that energy from coal will slightly decrease and energy from natural gas will increase. TECO projects that renewable energy will increase from 0.6 percent to 6.6 percent by 2028. TECO projects the sixth highest percentage of renewable energy generation in 2028 of the TYSP Utilities.

**Table 16: TECO Energy Consumption by Fuel Type**

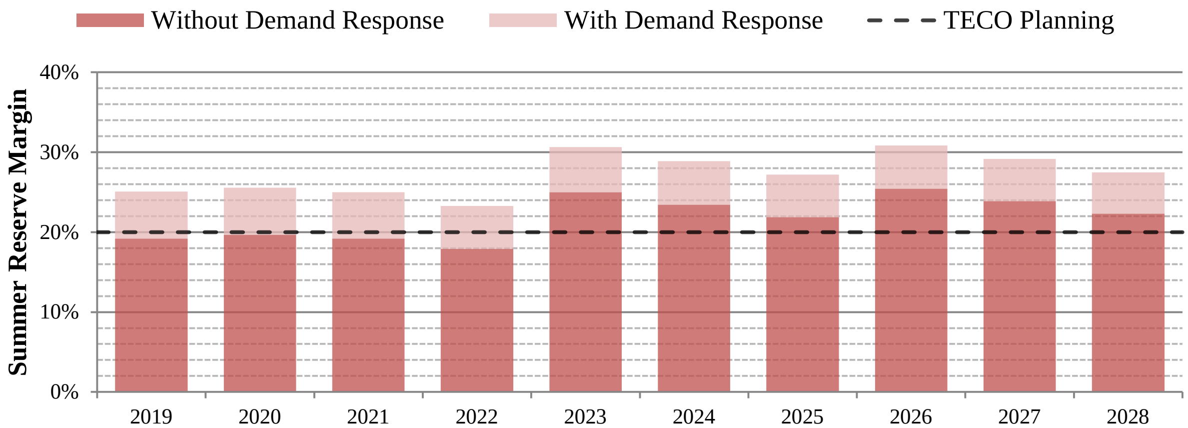
| Fuel Type | Net Energy for Load | | | |
|---|---|---|---|---|
| | 2018 | | 2028 | |
| | GWh | % | GWh | % |
| **Natural Gas** | 16,097 | **77.9%** | 17,729 | **78.4%** |
| **Coal** | 2,982 | **14.4%** | 2,836 | **12.5%** |
| **Nuclear** | 0 | **0.0%** | 0 | **0.0%** |
| **Oil** | 0 | **0.0%** | 0 | **0.0%** |
| **Renewable** | 118 | **0.6%** | 1,491 | **6.6%** |
| **Interchange** | 89 | **0.4%** | 0 | **0.0%** |
| **NUG & Other** | 1,376 | **6.7%** | 566 | **2.5%** |
| **Total** | **20,662** | | **22,622** | |

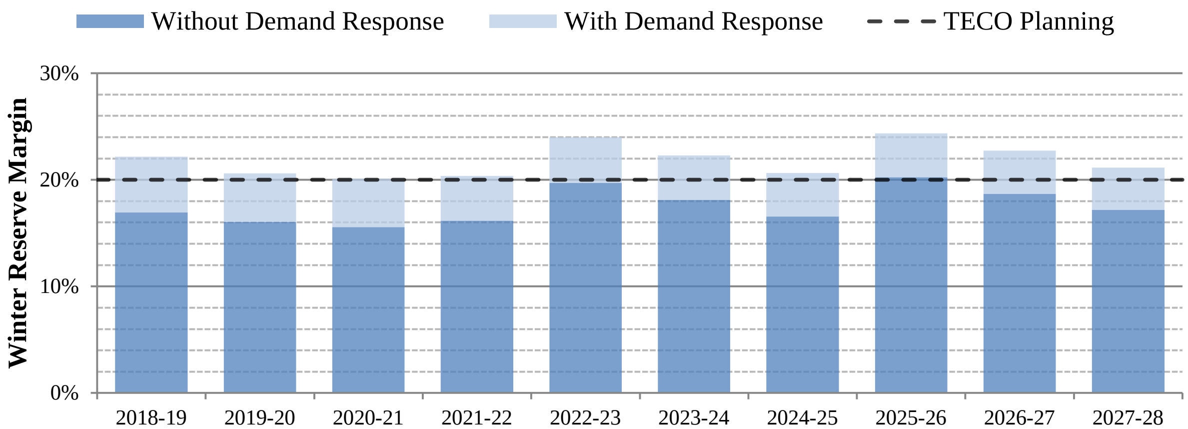
Source: 2019 Ten-Year Site Plan and Data Responses

## Reliability Requirements

Since 1999, TECO has utilized a 20 percent planning reserve margin criterion. TECO also elects to maintain a minimum supply-side reserve margin of 7 percent. Figure 26 displays the forecast planning reserve margin for TECO through the planning period for both seasons, with and without the use of demand response. As shown in the figure, TECO's generation needs are controlled by its summer peak throughout the planning period. TECO's 7 percent supply-side only reserve margin is not the controlling factor for any planned unit additions. However, it does provide useful information regarding the assurance that the projected 20 percent reserve margin will be realized.

**Figure 26: TECO Reserve Margin Forecast**




Source: 2019 Ten-Year Site Plan

## Generation Resources

TECO plans a unit retirement and multiple unit additions during the planning period, as described in Table 17. TECO anticipates retiring its coal-fired Big Bend Unit 2 in 2021. TECO also plans to convert its coal-fired Big Bend Unit 1 steam turbine into a natural gas-fired combined cycle unit by 2023. The Florida Department of Environmental Protection has determined that a determination of need is not necessary for this conversion. TECO also plans the addition of two natural gas-fired combustion turbine peaking units in 2023 and 2026, and anticipates increasing the amount of planned solar projects over the planning period.

TECO has included 84.5 MW of planned solar additions outside of its SoBRA units, 405 MW of which are already Commission-approved.[24,25] Another 149 MW of SoBRA additions are the subject of an active Commission docket.[26] All planned solar additions make up approximately 30 percent of TECO's planned future units.

TECO is installing a 12.6 MW Li-ion storage system at its Big Bend Solar site in Hillsborough County in 2019. This facility will be interconnected with the solar array and will add 5.6 MW of firm capacity. The expected project benefits include firming of the solar output during peak times and contribution to contingency reserves. TECO will continue to analyze storage technology and its applications with the objective to integrate these resources into our portfolio.

[24]Order No. PSC-2018-0288-FOF-EI, issued June 5, 2018, in Docket No. 20170260-EI, *In re: Petition for limited proceeding to approve first solar base rate adjustment (SoBRA), effective September 1, 2018, by Tampa Electric Company*.

[25]Order No. PSC-2018-0571-FOF-EI, issued December 07, 2018, in Docket No. 20180133-EI, *In re: Petition for limited proceeding to approve second solar base rate adjustment (SoBRA), effective January 1, 2019, by Tampa Electric Company*.

[26]Document No. 05259-2019, filed June 28, 2019, in Docket No. 20190136-EI, *In re: Petition for a limited proceeding to approve third SoBRA, by Tampa Electric Company*.

**Table 17: TECO Generation Resource Changes**

| Year | Plant Name & Unit Number | Unit Type | Net Capacity (MW) Sum | Solar Firm Capacity (Summer) Sum | Notes |
|---|---|---|---|---|---|
| **Retiring Units** | | | | | |
| 2021 | Big Bend 2 | BIT – ST | 385 | N/A | |
| **Total Retirements** | | | **385** | | |
| **New Units** | | | | | |
| 2019 | Bonnie Mine Solar[1] | PV | 38 | 18 | These SoBRA units received Commission approval in Docket No. 20180133-EI. Only 18 MW of the Lake Hancock project where approved. |
| 2019 | Grange Hall Solar[1] | PV | 61 | 33 | |
| 2019 | Lithia Solar[1] | PV | 75 | 39 | |
| 2019 | Peace Creek Solar[1] | PV | 55 | 31 | |
| 2019 | Lake Hancock[1] | PV | 50 | 26 | |
| 2020 | Little Manatee River[2] | PV | 75 | 39 | These SoBRA units are the subject of an active Commission docket, Docket No. 20190136-EI. |
| 2020 | Wimauma Solar[2] | PV | 75 | 43 | |
| 2021 | Big Bend 5 & 6 | NG – CT | 660 | N/A | |
| 2021 | Mountain View | PV | 53 | 30 | |
| 2023 | Future CT 1 | NG – CT | 229 | N/A | |
| 2026 | Future CT 2 | NG – CT | 229 | N/A | |
| **Total New Units** | | | **1,597** | **259** | |
| **Percentage of Solar Units Planned of Total New Units** | | | **30%** | | |
| **Net Additions** | | | **1,212** | | |

Source: 2019 Ten-Year Site Plan

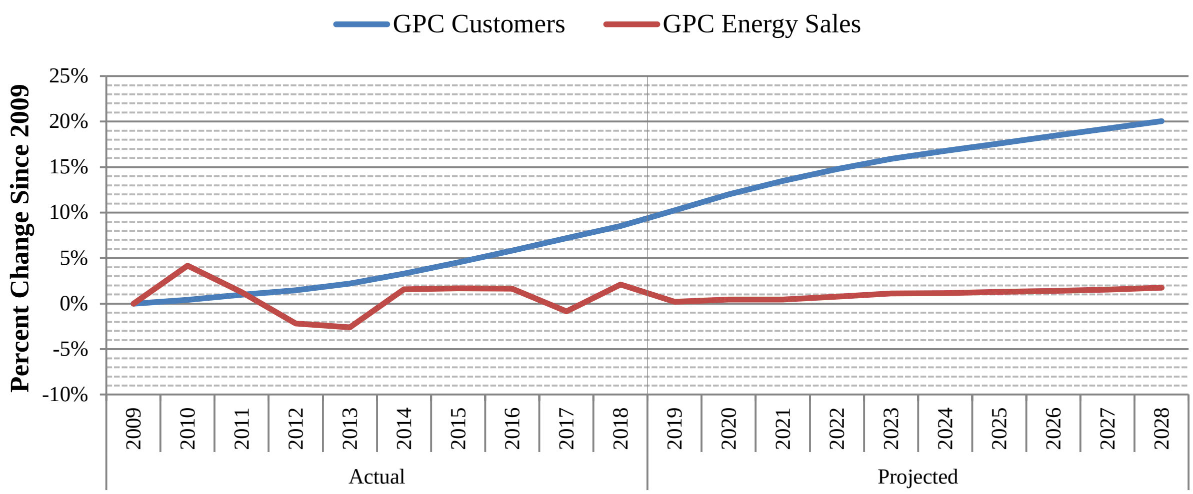
# Gulf Power Company (GPC)

GPC is an investor owned utility, and is Florida's sixth largest electric utility. It represents the smallest of the generating investor-owned utilities, and the only one inside the Southern Company electric system. As GPC plans and operates its system in conjunction with the other Southern Company utilities, not all of the energy generated by GPC is consumed within Florida. NextEra Energy Inc., FPL's parent company, has recently acquired GPC through a purchase that closed during the first half of 2019. Starting in 2020, Gulf's planning services will be performed by the resource planning group at FPL, and Gulf's 2020 Ten-Year Site Plan will reflect the results of these analyses. As an investor-owned utility, the Commission has regulatory authority over all aspects of operations, including rates, reliability, and safety. Pursuant to Section 186.801(2), F.S., the Commission finds GPC's 2019 Ten-Year Site Plan suitable for planning purposes.

## Load & Energy Forecasts

In 2018, GPC had approximately 464,682 customers and annual retail energy sales of 11,132 GWh or approximately 4.8 percent of Florida's annual retail energy sales. Figure 27 illustrates the Utility's historic and forecast number of customers and retail energy sales, in terms of percentage growth from 2009. Over the last 10 years, GPC's customer base has increased by 8.52 percent, while retail sales have increased by 2.11 percent. As illustrated, Gulf's retail energy sales are not anticipated to exceed its historic 2010 peak during the planning period.

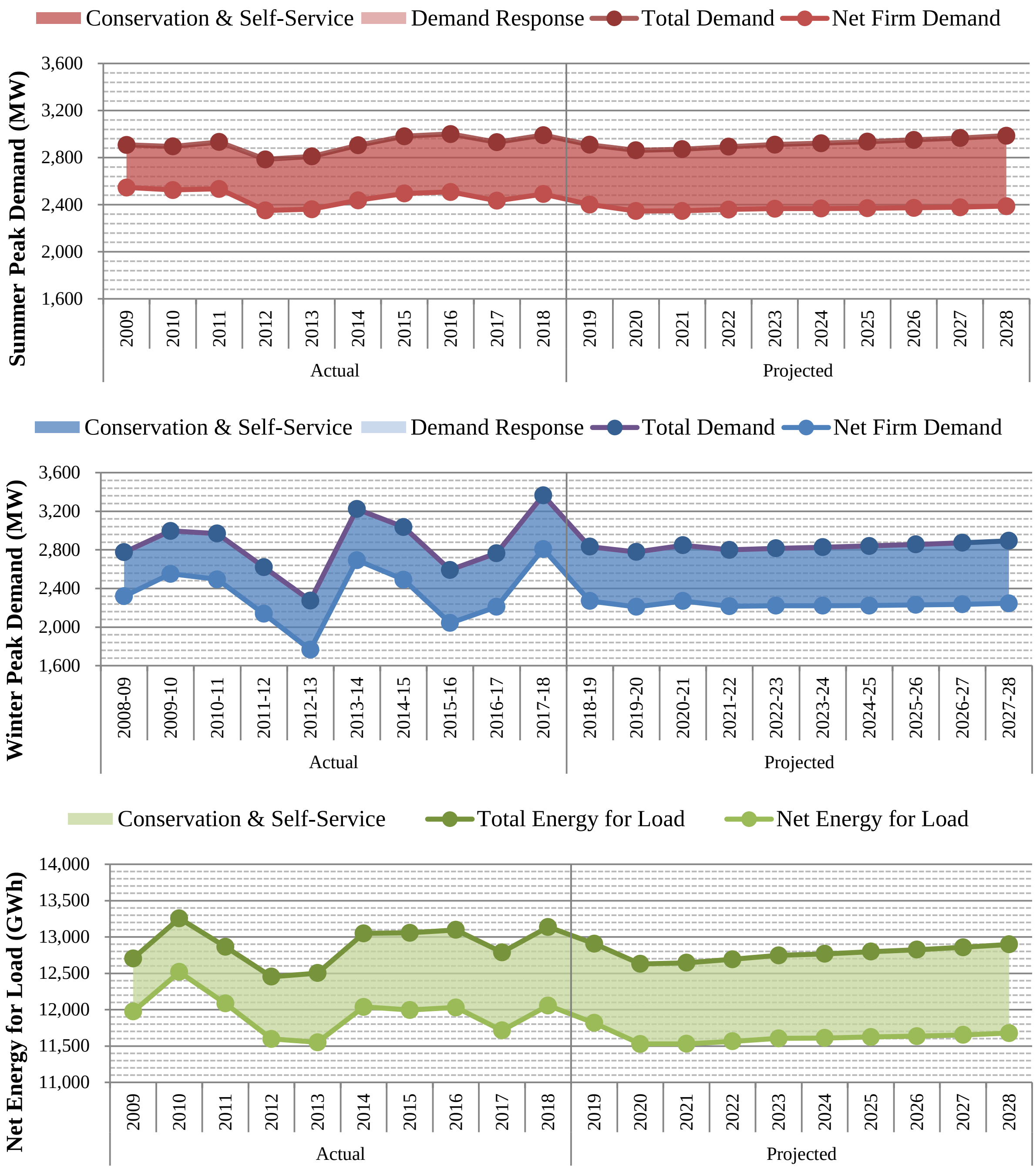
**Figure 27: GPC Growth**




Source: 2019 Ten-Year Site Plan

As an investor-owned utility, GPC is subject to FEECA and currently offers energy efficiency and demand response programs to customers to reduce peak demand and annual energy consumption. The Utility's 2019 Ten-Year Site Plan effects the revised demand-side management goals established by the Commission in December 2014. The three graphs in Figure 28 shows GPC's seasonal peak demand and net energy for load for the historic years of 2009 through 2018 and forecast years 2019 through 2028. These graphs include the full impact of demand-side management.

**Figure 28: GPC Demand and Energy Forecasts**




Source: 2019 Ten-Year Site Plan and Data Responses

## Fuel Diversity

Table 18 shows GPC's actual net energy for load by fuel type as of 2018, and the projected fuel mix for 2028. GPC is an energy exporter, producing approximately 26 percent more energy than it requires for native load. While natural gas was the dominant fuel source in 2018, coal was the second most utilized fuel source. By 2028, GPC's 2019 TYSP projects an increase in energy exports of 31 percent of native load. GPC projects energy from coal will increase to approximately 57 percent of system energy by the year 2028, the highest percentage of energy consumption from coal in 2028 of the TYSP Utilities. GPC projects the fourth highest percentage of renewable energy generation in 2028 of the TYSP Utilities.

**Table 18: GPC Energy Consumption by Fuel Type**

| Fuel Type | Net Energy for Load | | | |
|---|---|---|---|---|
| | 2018 | | 2028 | |
| | GWh | % | GWh | % |
| **Natural Gas** | 8,150 | **67.6%** | 7,237 | **62.0%** |
| **Coal** | 5,526 | **45.8%** | 6,637 | **56.8%** |
| **Nuclear** | 0 | **0.0%** | 0 | **0.0%** |
| **Oil** | 1 | **0.0%** | 0 | **0.0%** |
| **Renewable** | 1,327 | **11.0%** | 1,273 | **10.9%** |
| **Interchange** | -3,095 | **-25.7%** | -3,624 | **-31.0%** |
| **NUG & Other** | 148 | **1.2%** | 155 | **1.3%** |
| **Total** | **12,057** | | **11,678** | |

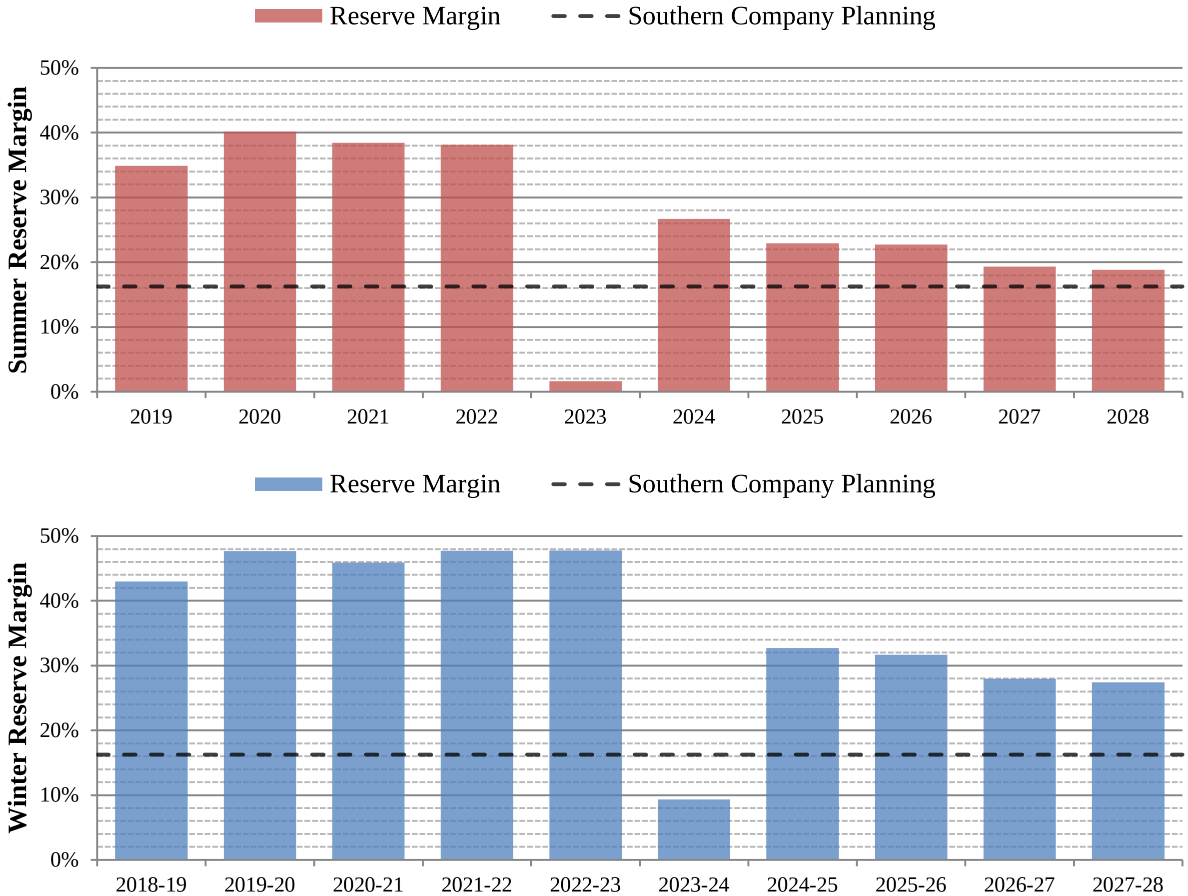
Source: 2019 Ten-Year Site Plan and Data Responses

## Reliability Requirements

As previously noted, GPC is the only TYSP utility outside of the FRCC region. As part of Southern Company's electric system, GPC plans to maintain a 16.25 percent summer reserve margin for the year 2022 and beyond. Figure 29 displays the forecast planning reserve margin for GPC through the planning period for both seasons, including the impact of energy efficiency programs.

As shown in Figure 29, GPC is reporting a 1.6 percent reserve margin for summer 2023 and a 9.3 percent reserve margin for winter 2023-24. This is due to the expiration of a purchased power agreement with Shell Energy North America (Shell PPA) for 885 MW of firm capacity in May 2023. GPC currently anticipates replacing a portion of this lost capacity with a 595 MW 1x1 combined cycle unit in June 2024. GPC expects to manage its reserve margin requirements in the interim, between the expiration of the Shell PPA and the in-service date of its anticipated new combined cycle unit, with short-term arrangements that are available through the Intercompany Interchange Contract's reserve sharing mechanism or through capacity purchases from the market. The Intercompany Interchange Contract's reserve sharing mechanism is a benefit afforded to GPC from its association with the Southern electric system. However, while GPC expects that these purchases will serve to meet its reserve margin requirements, it has not included any contributed capacity from the purchases into its reserve margin projections due to their nature as market purchases. The FRCC's reserve margin is projected to be 30 percent in 2023 at the time of summer peak, and is projected to be 41 percent in 2023/24 at the time of winter peak. As shown below, GPC's generation needs are typically determined by its summer peak.

**Figure 29: GPC Reserve Margin Forecast**




Source: 2019 Ten-Year Site Plan

## Generation Resources

GPC plans a few unit retirements and additions during the planning period, as described in Table 19. Pea Ridge natural gas-fired combustion turbines 1-3 are scheduled to be retired in 2025. GPC has also indicated that the coal-fired units Crist 4 & 5 are tentatively scheduled for retirement in 2024 and 2026, respectively. GPC has indicated these retirement dates borrow from end-of-life depreciation calculations and do not represent results from an operational evaluation of the units.

Based on its 2019 Ten-Year Site Plan, GPC plans to add a natural gas-fired combined cycle unit in 2024 after the expiration of the Shell PPA. The planned combined cycle addition will require a determination of need from the Commission.

**Table 19: GPC Generation Resource Changes**

| Year | Plant Name & Unit Number | Unit Type | Net Capacity (MW) Sum | Notes |
|---|---|---|---|---|
| **Retiring Units** | | | | |
| 2024 | Crist 4 | BIT – ST | 75 | |
| 2025 | Pea Ridge 1 – 3 | NG – CT | 12 | |
| 2026 | Crist 5 | BIT – ST | 75 | |
| **Total Retirements** | | | **162** | |
| **New Units** | | | | |
| 2024 | Combined Cycle 2[1] | NG – CC | 595 | This unit requires a determination of need by the Commission. |
| **Total New Units** | | | **595** | |
| **Net Additions** | | | **433** | |

Source: 2019 Ten-Year Site Plan

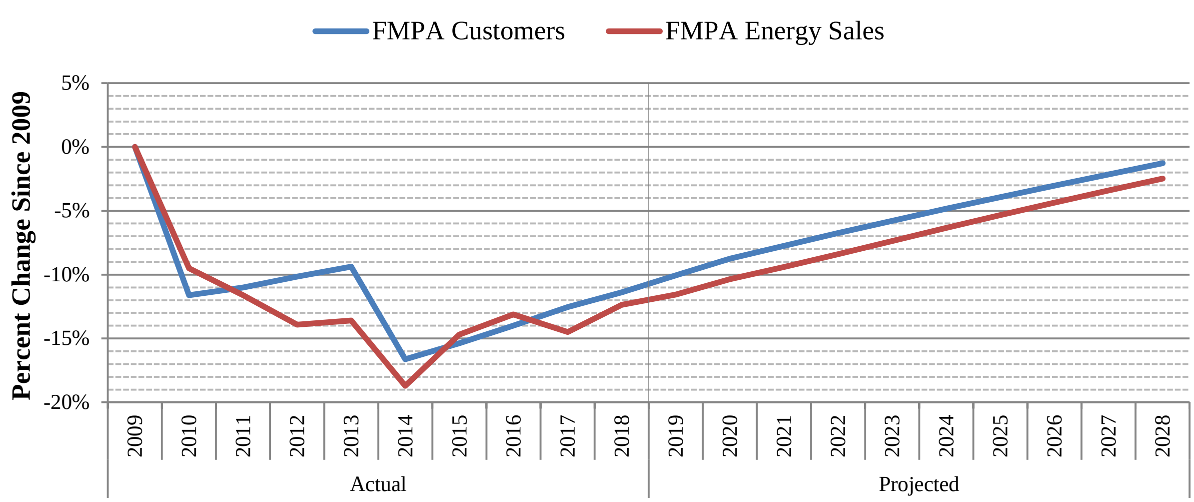
# Florida Municipal Power Agency (FMPA)

FMPA is a governmental wholesale power company owned by several Florida municipal utilities throughout Florida. Collectively, FMPA is Florida's eighth largest electric utility and third largest municipal electric utility. While FMPA has 31 member systems, only those members who are participants in the All-Requirements Power Supply Project (ARP) are addressed in the Utility's Ten-Year Site Plan. FMPA is responsible for planning activities associated with ARP member systems. As a municipal utility, the Commission's regulatory authority is limited to safety, rate structure, territorial boundaries, bulk power supply, operations, and planning. Pursuant to Section 186.801(2), F.S., the Commission finds FMPA's 2019 Ten-Year Site Plan suitable for planning purposes.

### Load & Energy Forecasts

In 2018, FMPA had approximately 261,147 customers and annual retail energy sales of 5,771 GWh or approximately 2.5 percent of Florida's annual retail energy sales. Figure 30 illustrates the Utility's historic and forecast number of customers and retail energy sales in terms of percentage growth from 2009. Over the last 10 years, FMPA's customer base has decreased by 11.38 percent, while retail sales have decreased by 12.36 percent. As illustrated, FMPA's retail energy sales are not anticipated to exceed its historic 2009 peak during the planning period. The reduction in sales is associated with several ARP member systems modifying their contractual agreements with FMPA, such that FMPA no longer provides for the system's capacity and energy needs. Those member systems modifying agreements include the City of Vero Beach in 2010, the City of Lake Worth in 2014, the City of Fort Meade in 2015, and the City of Green Cove Springs in 2019.

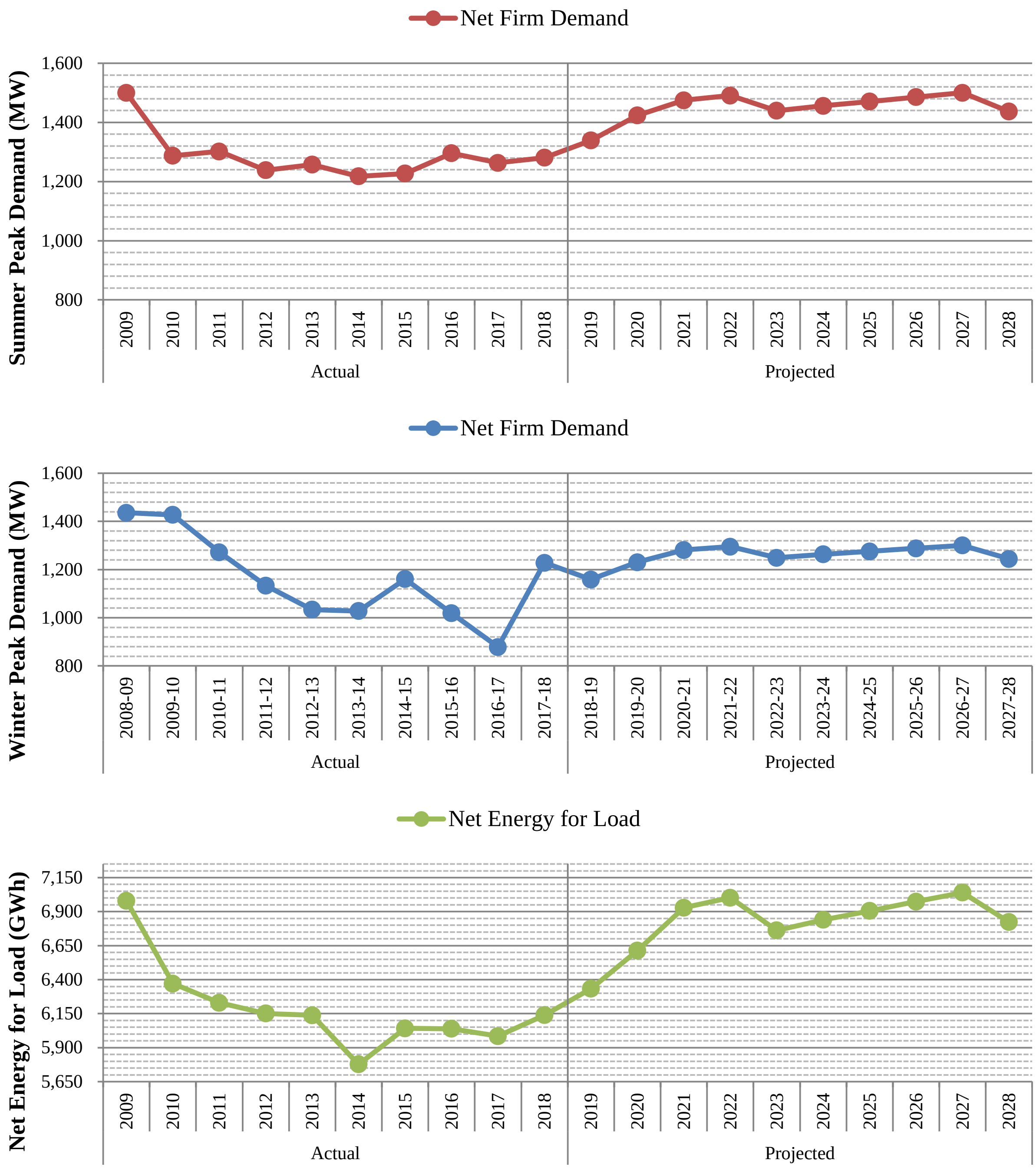
**Figure 30: FMPA Growth**




Source: 2019 Ten-Year Site Plan

The three graphs in Figure 31 show FMPA's seasonal peak demand and net energy for load for the historic years of 2009 through 2018 and forecast years 2019 through 2028. As FMPA is a wholesale power company, it does not directly engage in energy efficiency or demand response programs. ARP member systems do offer demand-side management programs, the impacts of which are included in the graphs.

**Figure 31: FMPA Demand and Energy Forecasts**




Source: 2019 Ten-Year Site Plan and Data Responses

## Fuel Diversity

Table 20 shows FMPA's actual net energy for load by fuel type as of 2018 and the projected fuel mix for 2028. FMPA uses natural gas as its primary fuel, supplemented by coal and nuclear generation. FMPA projects a decrease in energy generation from coal in 2028, but approximately 88.3 percent of energy would still be sourced from natural gas and nuclear.

**Table 20: FMPA Energy Consumption by Fuel Type**

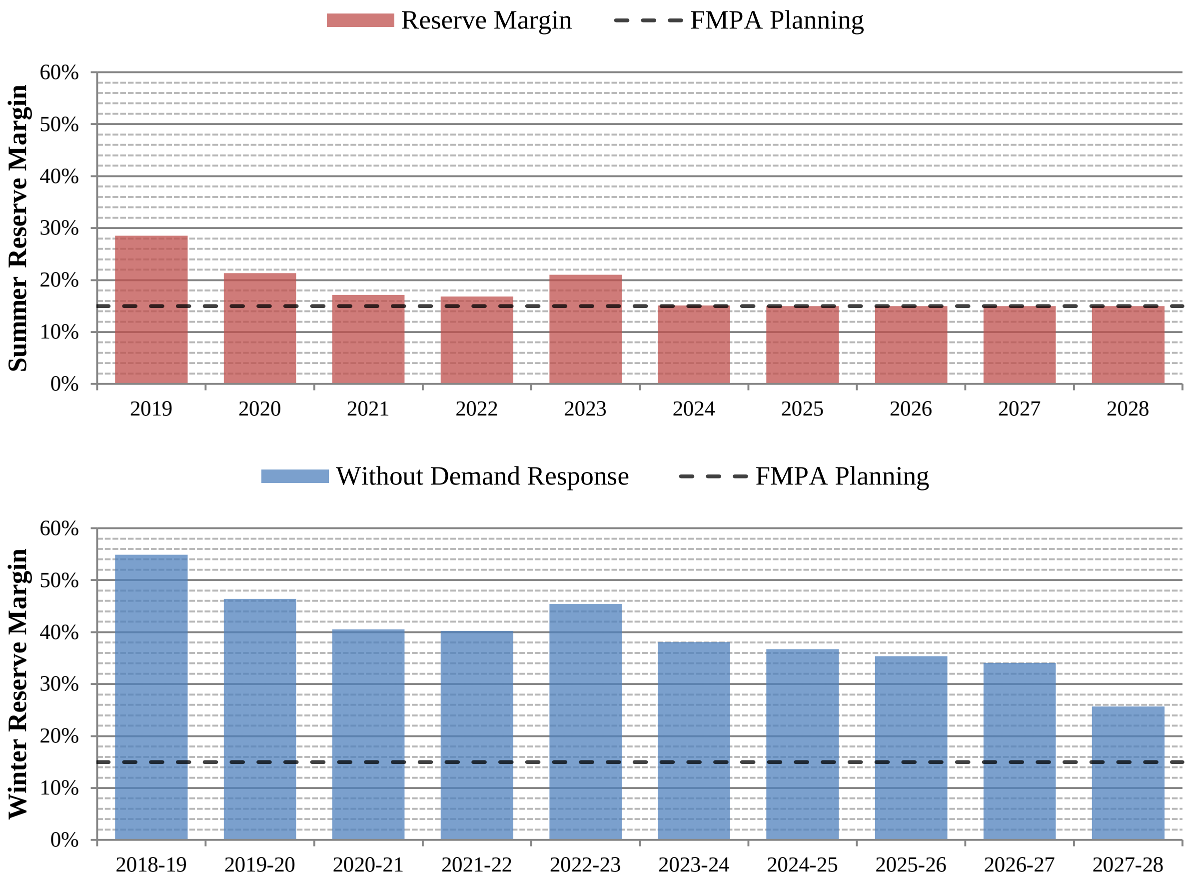
| Fuel Type | Net Energy for Load | | | |
|---|---|---|---|---|
| | 2018 | | 2028 | |
| | GWh | % | GWh | % |
| **Natural Gas** | 4,851 | **79.0%** | 5,635 | **82.6%** |
| **Coal** | 968 | **15.8%** | 529 | **7.7%** |
| **Nuclear** | 279 | **4.5%** | 391 | **5.7%** |
| **Oil** | 2 | **0.0%** | 0 | **0.0%** |
| **Renewable** | 39 | **0.6%** | 269 | **3.9%** |
| **Interchange** | 0 | **0.0%** | 0 | **0.0%** |
| **NUG & Other** | 0 | **0.0%** | 0 | **0.0%** |
| **Total** | **6,138** | | **6,824** | |

Source: 2019 Ten-Year Site Plan and Data Responses

## Reliability Requirements

FMPA utilizes a 15 percent planning reserve margin criterion. Figure 32 displays the forecast planning reserve margin for FMPA through the planning period for both seasons, with the impact of energy efficiency programs. As shown in the figure, FMPA's generation needs are controlled by its summer peak throughout the planning period.

**Figure 32: FMPA Reserve Margin Forecast**




Source: 2019 Ten-Year Site Plan

## Generation Resources

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

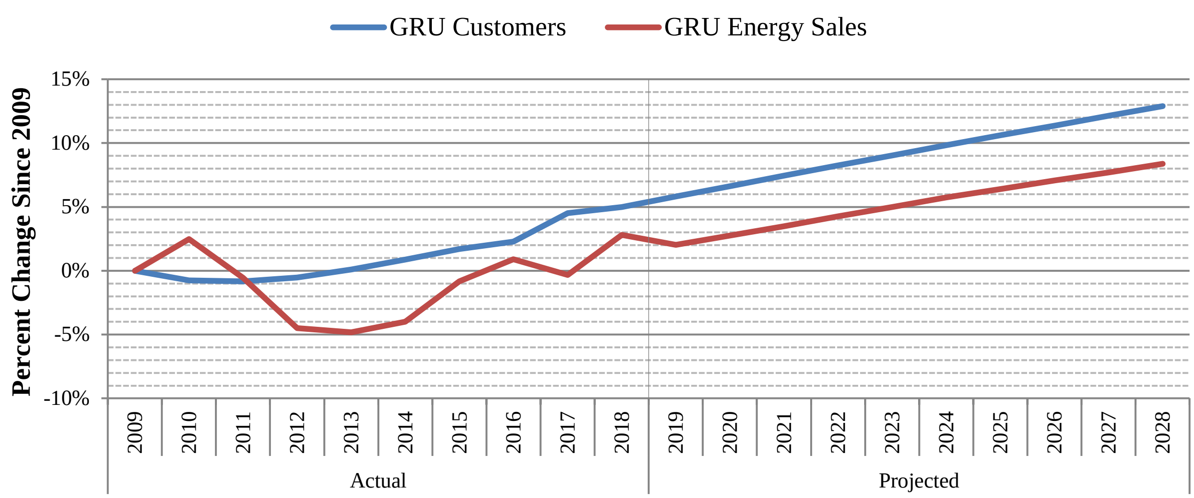
# Gainesville Regional Utilities (GRU)

GRU is a municipal utility and the smallest electric utility required to file a Ten-Year Site Plan. The Utility's service territory is within the FRCC region and consists of the City of Gainesville and its surrounding area. GRU also provides wholesale power to the City of Alachua and Clay Electric Cooperative. As a municipal utility, the Commission's regulatory authority is limited to safety, rate structure, territorial boundaries, bulk power supply, operations, and planning. Pursuant to Section 186.801(2), F.S., the Commission finds GRU's 2019 Ten-Year Site Plan suitable for planning purposes.

## Load & Energy Forecasts

In 2018, GRU had approximately 97,681 customers and annual retail energy sales of 1,830 GWh or approximately 0.8 percent of Florida's annual retail energy sales. Figure 33 illustrates the Utility's historic and forecast number of customers and retail energy sales, in terms of percentage growth from 2009. Over the last 10 years, GRU's customer base has increased by 4.98 percent, while retail sales have increased by 2.81 percent.

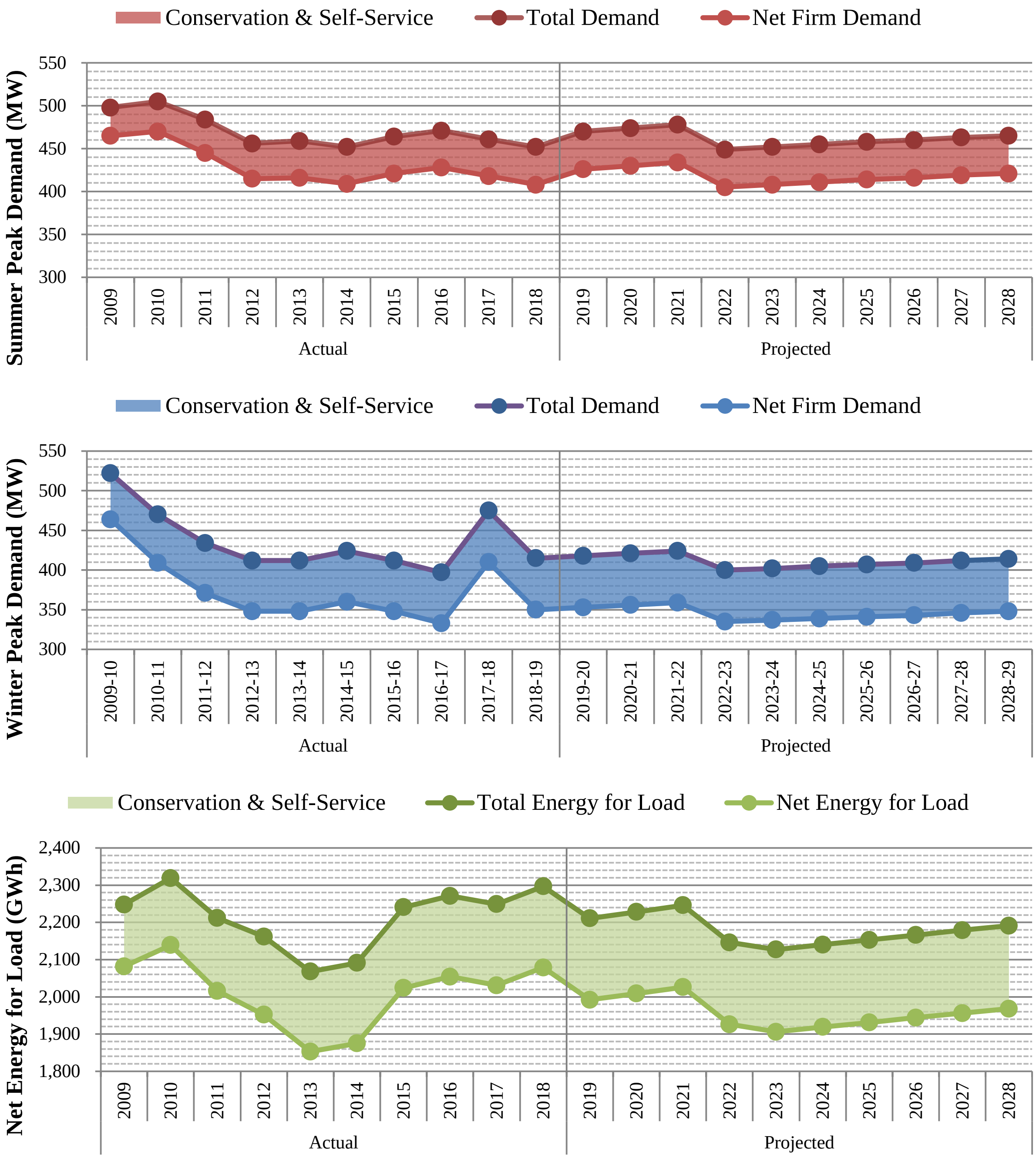
**Figure 33: GRU Growth**




Source: 2019 Ten-Year Site Plan

The three graphs in Figure 34 show GRU's seasonal peak demand and net energy for load for the historic years of 2009 through 2018 and forecast years 2019 through 2028. GRU engages in multiple energy efficiency programs to reduce customer peak demand and annual energy for load. The graphs in Figure 34 include the impact of these demand-side management programs.

## Figure 34: GRU Demand and Energy Forecasts




Source: 2019 Ten-Year Site Plan and Data Responses

## Fuel Diversity

Table 21 shows GRU's actual net energy for load by fuel type as of 2018 and the projected fuel mix for 2028. In 2018, natural gas was the primary fuel followed by renewables and coal respectively. By the year 2028, natural gas and renewables are expected to drop in usage while the energy obtained by burning coal is expected to increase.

**Table 21: GRU Energy Consumption by Fuel Type**

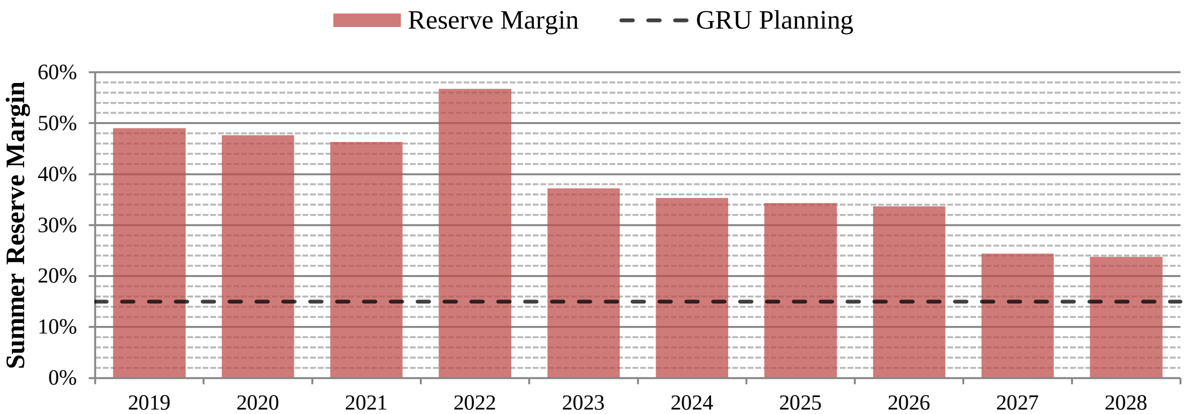
| Fuel Type | Net Energy for Load | | | |
|---|---|---|---|---|
| | 2018 | | 2028 | |
| | GWh | % | GWh | % |
| **Natural Gas** | 1,016 | **48.9%** | 903 | **45.9%** |
| **Coal** | 460 | **22.1%** | 720 | **36.6%** |
| **Nuclear** | 0 | **0.0%** | 0 | **0.0%** |
| **Oil** | 1 | **0.0%** | 0 | **0.0%** |
| **Renewable** | 595 | **28.6%** | 300 | **15.2%** |
| **Interchange** | 7 | **0.3%** | 45 | **2.3%** |
| **NUG & Other** | 0 | **0.0%** | 0 | **0.0%** |
| **Total** | **2,079** | | **1,968** | |

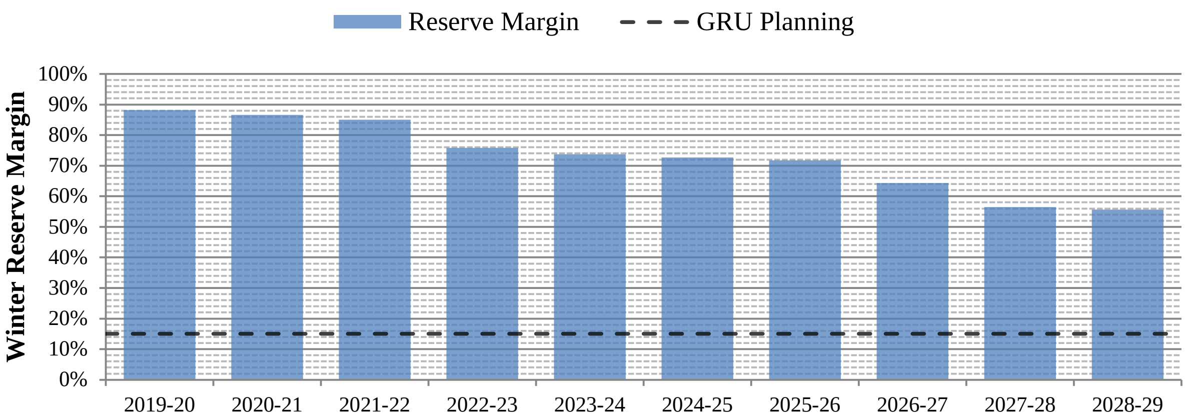
Source: 2019 Ten-Year Site Plan and Data Responses

## Reliability Requirements

GRU utilizes a 15 percent planning reserve margin criterion for seasonal peak demand. Figure 35 displays the forecast planning reserve margin for GRU through the planning period for both seasons, including the impacts of demand-side management. As shown in the figure, GRU's generation needs are controlled by its summer peak throughout the planning period. As a smaller utility, the reserve margin is an imperfect measure of reliability due to the relatively large impact a single unit may have on reserve margin. For example, GRU's largest single unit, Deerhaven 2, a coal-fired steam unit, represented 55.9 percent of its summer net firm peak demand in 2018.

**Figure 35: GRU Reserve Margin Forecast**




Source: 2019 Ten-Year Site Plan

## Generation Resources

GRU currently plans to retire a natural gas-fired steam unit in 2022, and two natural gas-fired combustion turbines in 2026, as described in Table 22. As a smaller utility, single units can have a large impact upon reserve margin.

**Table 22: GRU Generation Resource Changes**

| Year | Plant Name & Unit Number | Unit Type | Net Capacity (MW) Sum |
|---|---|---|---|
| **Retiring Units** | | | |
| 2022 | Deerhaven FS01 | NG – ST | 75 |
| 2026 | Deerhaven GT01 & GT02 | NG – GT | 35 |
| **Total Retirements** | | | **110** |
| **Net Additions** | | | **(110)** |

Source: 2019 Ten-Year Site Plan

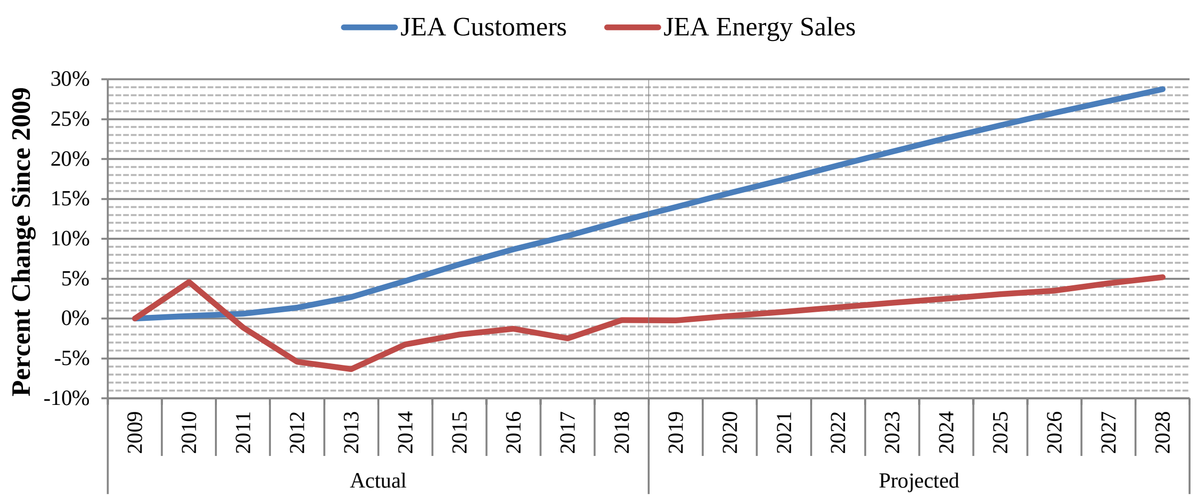
# JEA

JEA, formerly known as Jacksonville Electric Authority, is Florida's largest municipal utility and fifth largest electric utility. JEA's service territory is within the FRCC region, and includes all of Duval County as well as portions of Clay and St. Johns Counties. As a municipal utility, the Commission's regulatory authority is limited to safety, rate structure, territorial boundaries, bulk power supply, operations, and planning. Pursuant to Section 186.801(2), F.S., the Commission finds JEA's 2019 Ten-Year Site Plan suitable for planning purposes.

## Load & Energy Forecasts

In 2018, JEA had approximately 464,793 customers and annual retail energy sales of 12,085 GWh or approximately 5.3 percent of Florida's annual retail energy sales. Figure 36 illustrates the Utility's historic and forecast number of customers and retail energy sales, in terms of percentage growth from 2009. Over the last 10 years, JEA's customer base has increased by 12.25 percent, while retail sales have decreased by 0.17 percent. As illustrated, JEA's retail energy sales are not anticipated to exceed its historic 2010 peak until 2028.

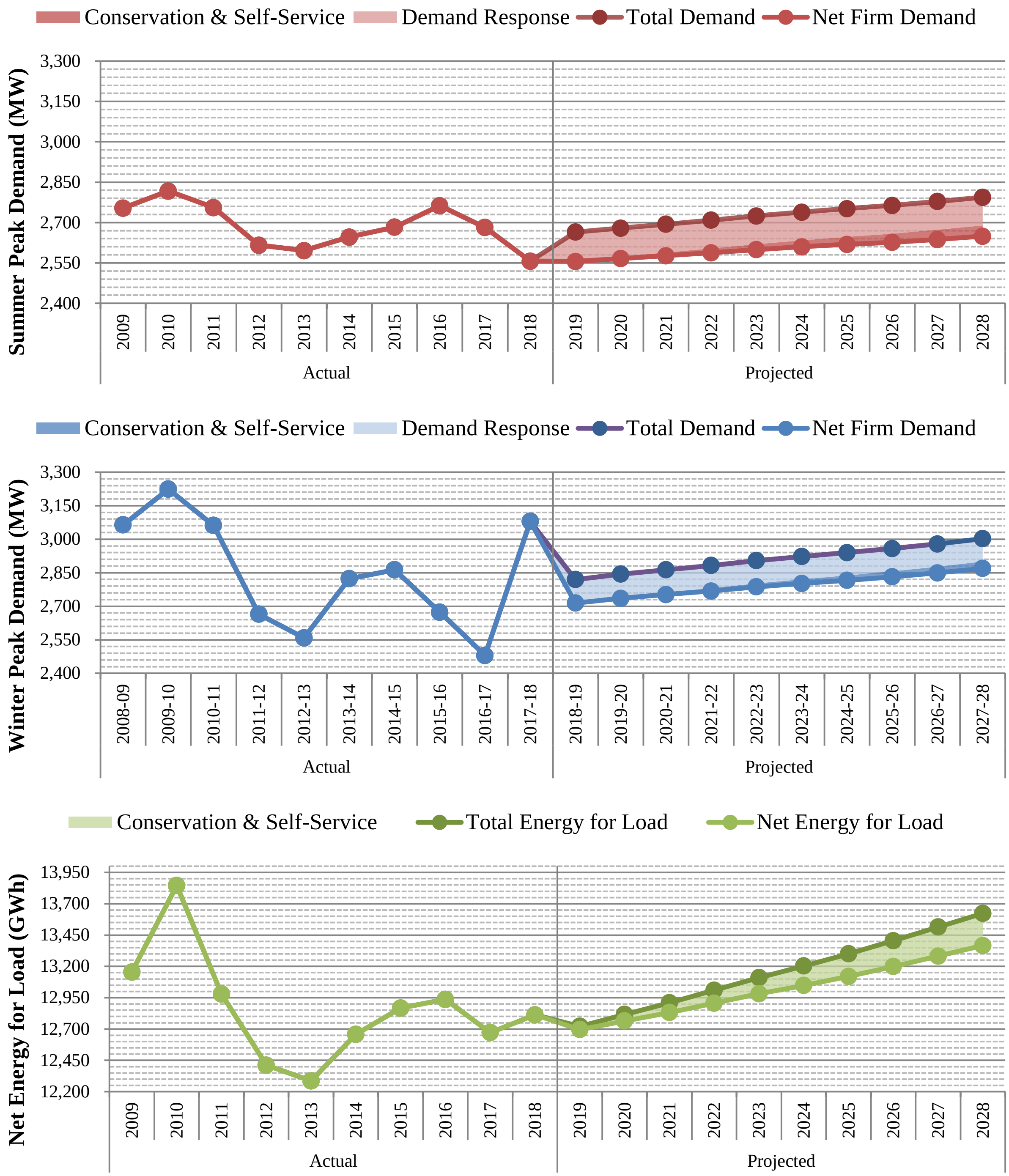
**Figure 36: JEA Growth**




Source: 2019 Ten-Year Site Plan

The three graphs in Figure 37 show JEA's seasonal peak demand and net energy for load for the historic years of 2009 through 2018 and forecast years 2019 through 2028. These graphs include the full impact of demand-side management, and assume that all available demand response resources will be activated during the seasonal peak.

**Figure 37: JEA Demand and Energy Forecasts**




Source: 2019 Ten-Year Site Plan and Data Responses

While a municipal utility, JEA is subject to FEECA and currently offers energy efficiency and demand response programs to customers to reduce peak demand and annual energy consumption. The Utility's 2019 Ten-Year Site Plan reflects the revised demand-side management goals established by the Commission in December 2014.

### Fuel Diversity

Table 23 shows JEA's actual net energy for load by fuel type as of 2018 and the projected fuel mix for 2028. While natural gas was the dominant fuel source in 2018, coal was JEA's second most utilized fuel source. JEA's 2019 Ten-Year Site plan projects that a majority of JEA's net energy for load will continue to come from natural gas and coal in 2028. JEA projects the third highest percentage of energy consumption from coal in 2028 of the TYSP Utilities.

**Table 23: JEA Energy Consumption by Fuel Type**

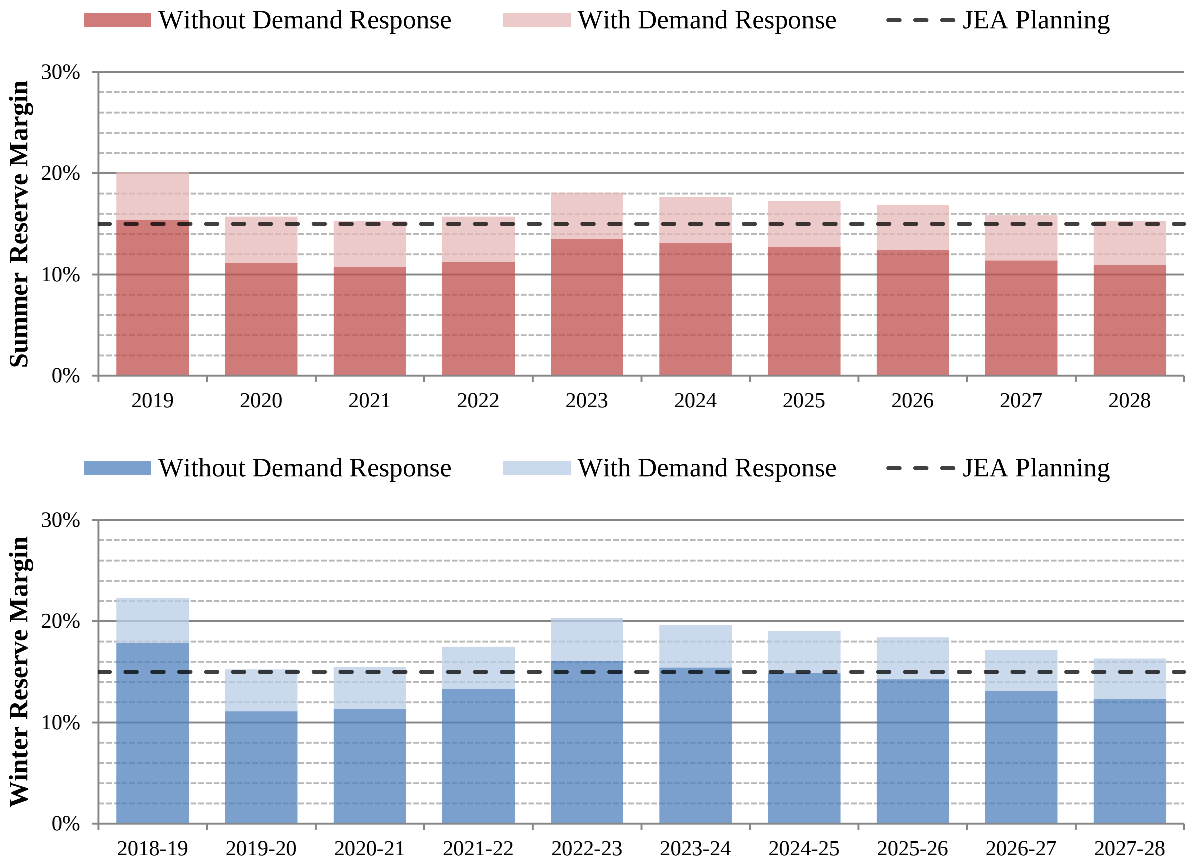
| Fuel Type | Net Energy for Load | | | |
|---|---|---|---|---|
| | 2018 | | 2028 | |
| | GWh | % | GWh | % |
| **Natural Gas** | 6,590 | **51.4%** | 6,275 | **46.9%** |
| **Coal** | 3,558 | **27.8%** | 4,808 | **36.0%** |
| **Nuclear** | 0 | **0.0%** | 0 | **0.0%** |
| **Oil** | 30 | **0.2%** | 1 | **0.0%** |
| **Renewable** | 149 | **1.2%** | 668 | **5.0%** |
| **Interchange** | 2,485 | **19.4%** | 1,615 | **12.1%** |
| **NUG & Other** | 0 | **0.0%** | 0 | **0.0%** |
| **Total** | **12,813** | | **13,366** | |

Source: 2019 Ten-Year Site Plan and Data Responses

### Reliability Requirements

JEA utilizes a 15 percent planning reserve margin criterion for seasonal peak demand. Figure 38 displays the forecast planning reserve margin for JEA through the planning period for both seasons, with and without the use of demand response. As shown in the figure, JEA's generation needs are controlled by its summer peak throughout the planning period.

**Figure 38: JEA Reserve Margin Forecast**




Source: 2019 Ten-Year Site Plan

## Generation Resources

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

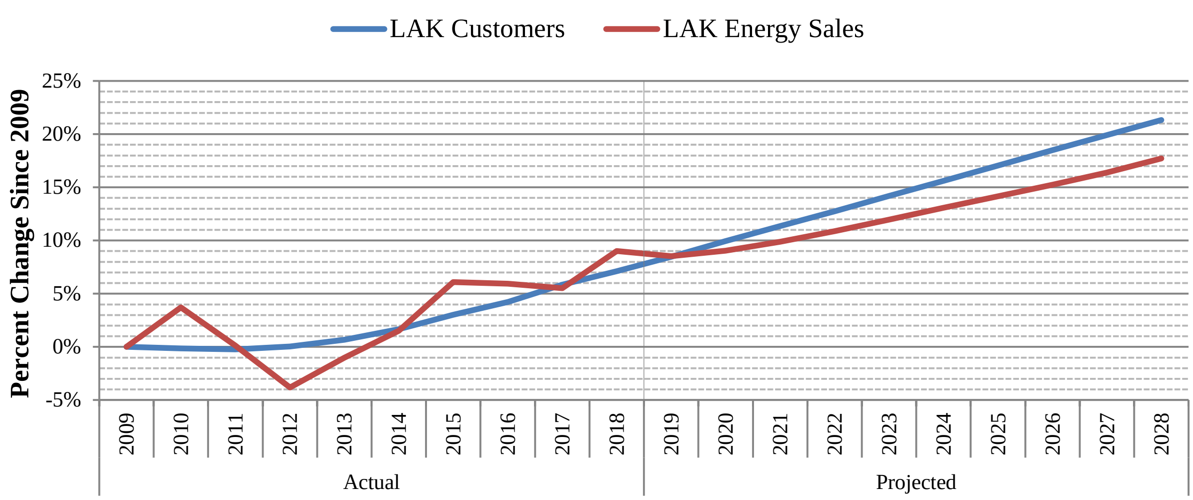
# Lakeland Electric (LAK)

LAK is a municipal utility and the state's third smallest electric utility required to file a Ten-Year Site Plan. The Utility's service territory is within the FRCC region and consists of the City of Lakeland and surrounding areas. As a municipal utility, the Commission's regulatory authority is limited to safety, rate structure, territorial boundaries, bulk power supply, operations, and planning. Pursuant to Section 186.801(2), F.S., the Commission finds LAK's 2019 Ten-Year Site Plan suitable for planning purposes.

### Load & Energy Forecasts

In 2018, LAK had approximately 130,657 customers and annual retail energy sales of 3,118 GWh or approximately 1.4 percent of Florida's annual retail energy sales. Figure 39 illustrates the Utility's historic and forecast number of customers and retail energy sales, in terms of percentage growth from 2009. Over the last 10 years, LAK's customer base has increased by 7.10 percent, while retail sales have grown by 9.02 percent.

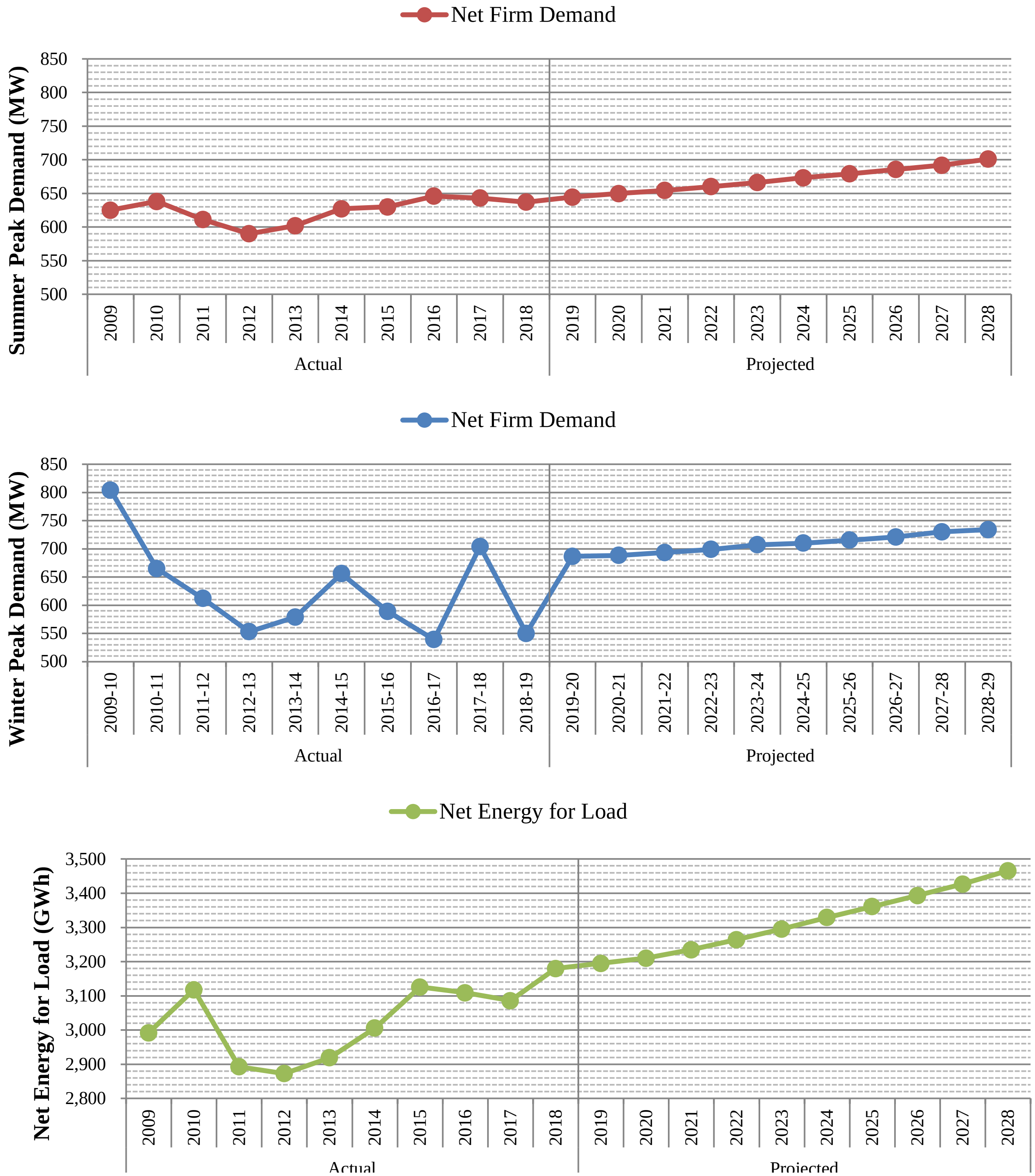
**Figure 39: LAK Growth**




Source: 2019 Ten-Year Site Plan

The three graphs in Figure 40 show LAK's seasonal peak demand and net energy for load for the historic years of 2009 through 2018 and forecast years 2019 through 2028. LAK offers energy efficiency programs, the impacts of which are included in the graphs.

**Figure 40: LAK Demand and Energy Forecasts**




Source: 2019 Ten-Year Site Plan and Data Responses

## Fuel Diversity

Table 24 shows LAK's actual net energy for load by fuel type as of 2018 and the projected fuel mix for 2028. LAK uses natural gas as its primary fuel type for energy, with coal representing about 30 percent net energy for load. While natural gas usage is anticipated to remain stable, coal is projected to decrease by 2028.

**Table 24: LAK Energy Consumption by Fuel Type**

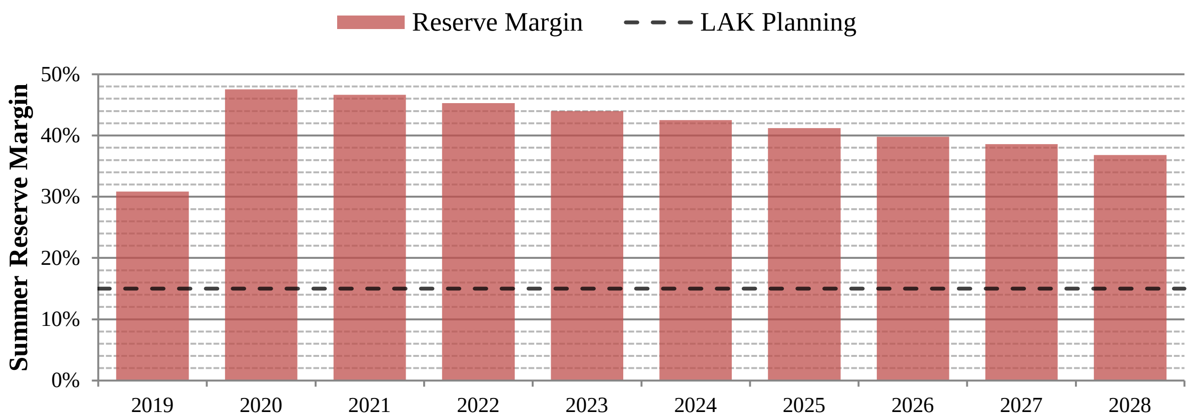
| Fuel Type | Net Energy for Load | | | |
|---|---|---|---|---|
| | 2018 | | 2028 | |
| | GWh | % | GWh | % |
| **Natural Gas** | 2,270 | **71.4%** | 2,471 | **71.3%** |
| **Coal** | 969 | **30.5%** | 508 | **14.7%** |
| **Nuclear** | 0 | **0.0%** | 0 | **0.0%** |
| **Oil** | 0 | **0.0%** | 1 | **0.0%** |
| **Renewable** | 26 | **0.8%** | 27 | **0.8%** |
| **Interchange** | -85 | **-2.7%** | 459 | **13.2%** |
| **NUG & Other** | 0 | **0.0%** | 0 | **0.0%** |
| **Total** | **3,180** | | **3,466** | |

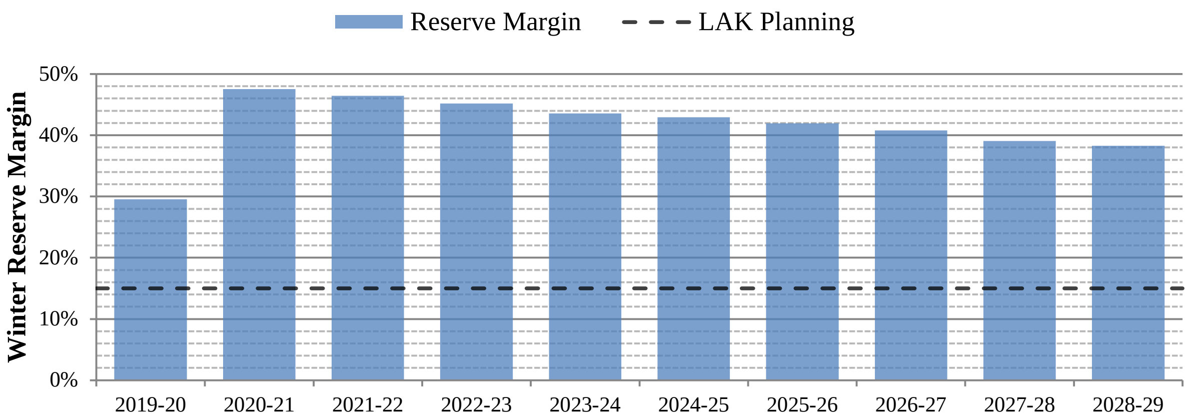
Source: 2019 Ten-Year Site Plan and Data Responses

## Reliability Requirements

LAK utilizes a 15 percent planning reserve margin criterion for seasonal peak demand. Figure 41 displays the forecast planning reserve margin for LAK through the planning period for both seasons, including the impacts of demand-side management. As a smaller utility, the reserve margin is an imperfect measure of reliability due to the relatively large impact a single unit may have on reserve margin. For example, LAK's largest single unit, McIntosh 5, a natural gas-fired combined cycle unit, represented 53.1 percent of summer net firm peak demand in 2018.

**Figure 41: LAK Reserve Margin Forecast**




Source: 2019 Ten-Year Site Plan

## Generation Resources

LAK plans on adding a single natural gas combustion turbine as shown in Table 25.

**Table 25: LAK Generation Resource Changes**

| Year | Plant Name & Unit Number | Unit Type | Net Capacity (MW) Sum |
|---|---|---|---|
| **New Units** | | | |
| 2020 | C.D. McIntosh 2 | NG – CT | 115 |
| **Net Additions** | | | **115** |

Source: 2019 Ten-Year Site Plan and Data Responses

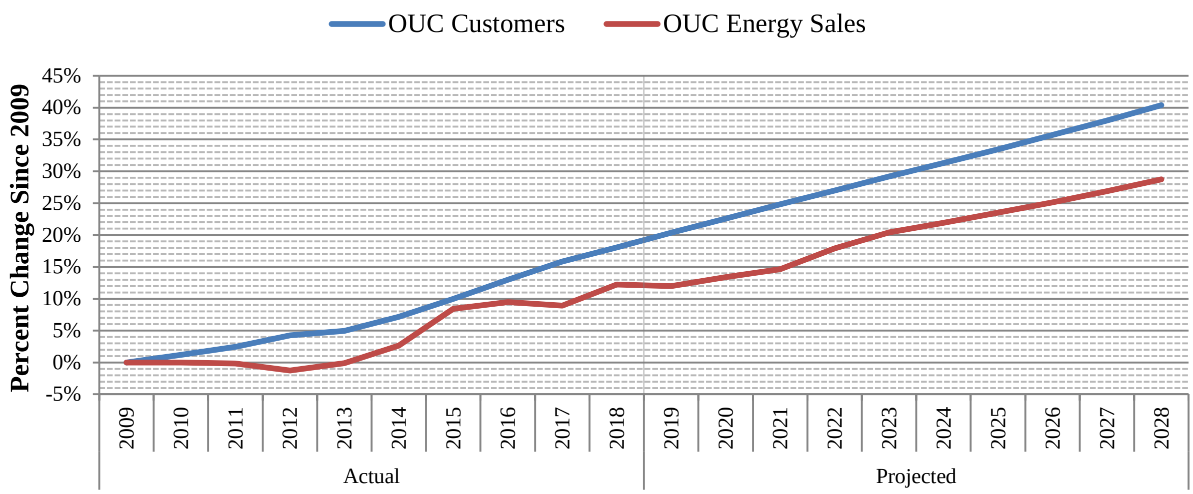
# Orlando Utilities Commission (OUC)

OUC is a municipal utility and Florida's seventh largest electric utility and second largest municipal utility. The Utility's service territory is within the FRCC region and primarily consists of the Orlando metropolitan area. As a municipal utility, the Commission's regulatory authority is limited to safety, rate structure, territorial boundaries, bulk power supply, operations, and planning. Pursuant to Section 186.801(2), F.S., the Commission finds OUC's 2019 Ten-Year Site Plan suitable for planning purposes.

### Load & Energy Forecasts

In 2018, OUC had approximately 241,628 customers and annual retail energy sales of 6,769 GWh or approximately 2.9 percent of Florida's annual retail energy sales. Figure 42 illustrates the Utility's historic and forecast number of customers and retail energy sales, in terms of percentage growth from 2009. Over the last 10 years, OUC's customer base has increased by 18.07 percent, while retail sales have grown by 12.25 percent.

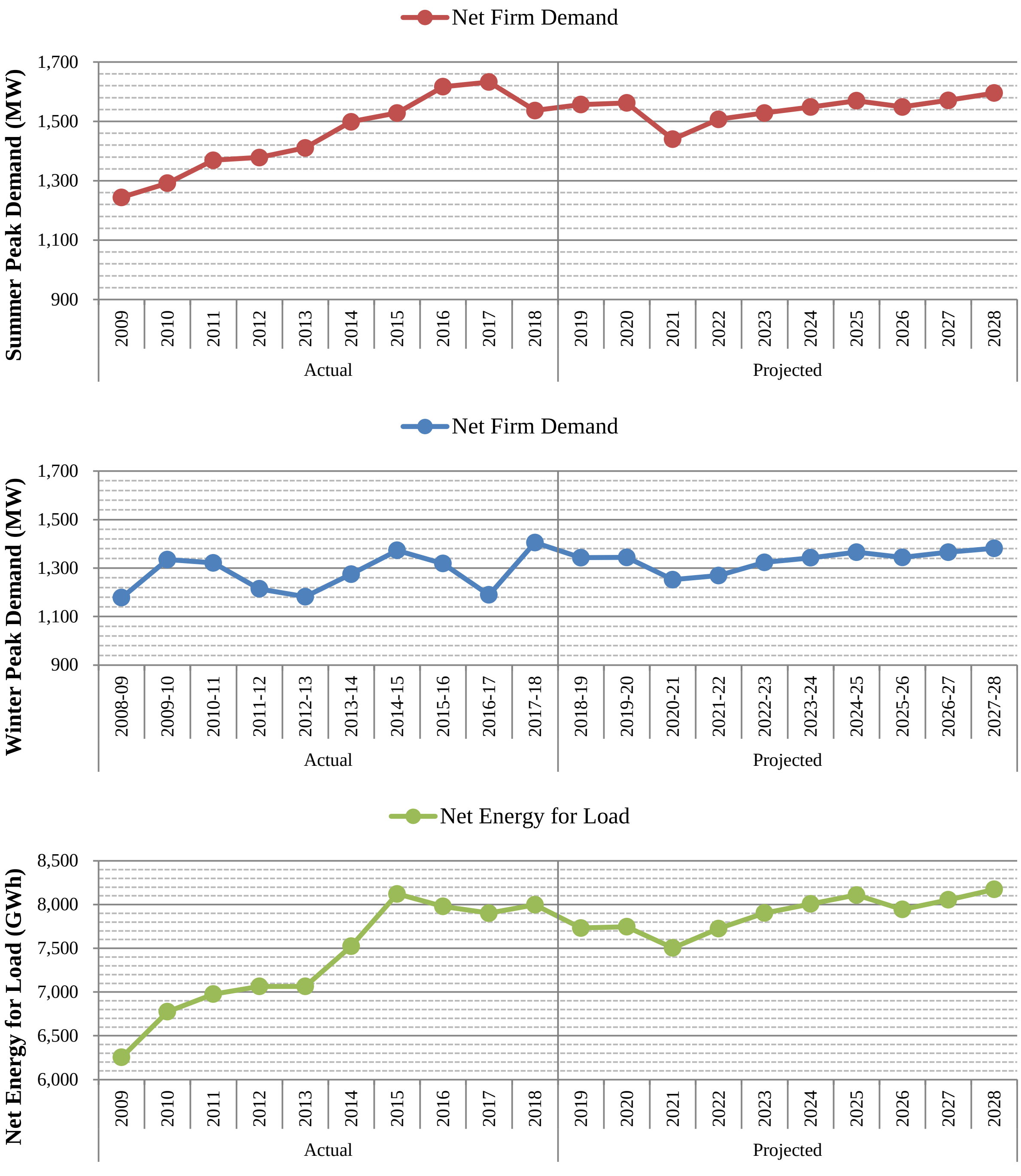
**Figure 42: OUC Growth**




Source: 2019 Ten-Year Site Plan

The three graphs in Figure 43 show OUC's seasonal peak demand and net energy for load for the historic years of 2009 through 2018 and forecast years 2019 through 2028. These graphs include the impact of the Utility's demand side management programs. While a municipal utility, OUC is subject to FEECA and currently offers energy efficiency programs to customers to reduce peak demand and annual energy consumption.

**Figure 43: OUC Demand and Energy Forecasts**




Source: 2019 Ten-Year Site Plan and Data Responses

## Fuel Diversity

Table 26 shows OUC's actual net energy for load by fuel type as of 2018 and the projected fuel mix for 2028. In 2018, approximately 53 percent of OUC's net energy for load was met with coal, while natural gas, the second most-used fuel, met 39 percent. By 2028, OUC projects to meet 62 percent of its net energy for load with natural gas, while coal use is expected to decrease to 24 percent.

**Table 26: OUC Energy Consumption by Fuel Type**

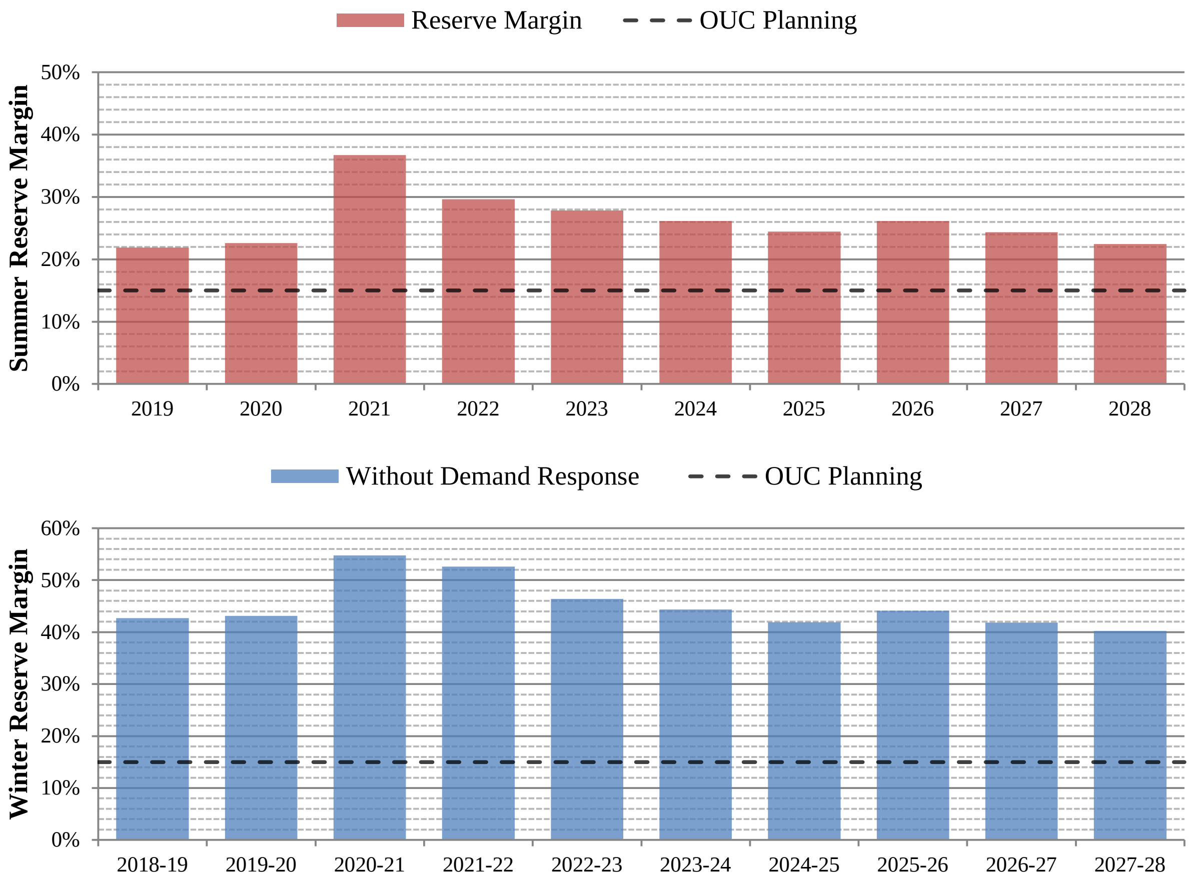
| Fuel Type | Net Energy for Load | | | |
|---|---|---|---|---|
| | 2018 | | 2028 | |
| | GWh | % | GWh | % |
| **Natural Gas** | 3,138 | **39.2%** | 5,037 | **61.6%** |
| **Coal** | 4,204 | **52.6%** | 1,964 | **24.0%** |
| **Nuclear** | 470 | **5.9%** | 561 | **6.9%** |
| **Oil** | 0 | **0.0%** | 0 | **0.0%** |
| **Renewable** | 185 | **2.3%** | 611 | **7.5%** |
| **Interchange** | 0 | **0.0%** | 0 | **0.0%** |
| **NUG & Other** | 0 | **0.0%** | 0 | **0.0%** |
| **Total** | **7,997** | | **8,173** | |

Source: 2019 Ten-Year Site Plan and Data Responses

## Reliability Requirements

OUC utilizes a 15 percent planning reserve margin criterion for seasonal peak demand. Figure 44 displays the forecast planning reserve margin for OUC through the planning period for both seasons, including the impact of demand-side management programs. As shown in the figure, OUC's generation needs are controlled by its summer peak demand throughout the planning period.

**Figure 44: OUC Reserve Margin Forecast**




Source: 2019 Ten-Year Site Plan

## Generation Resources

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

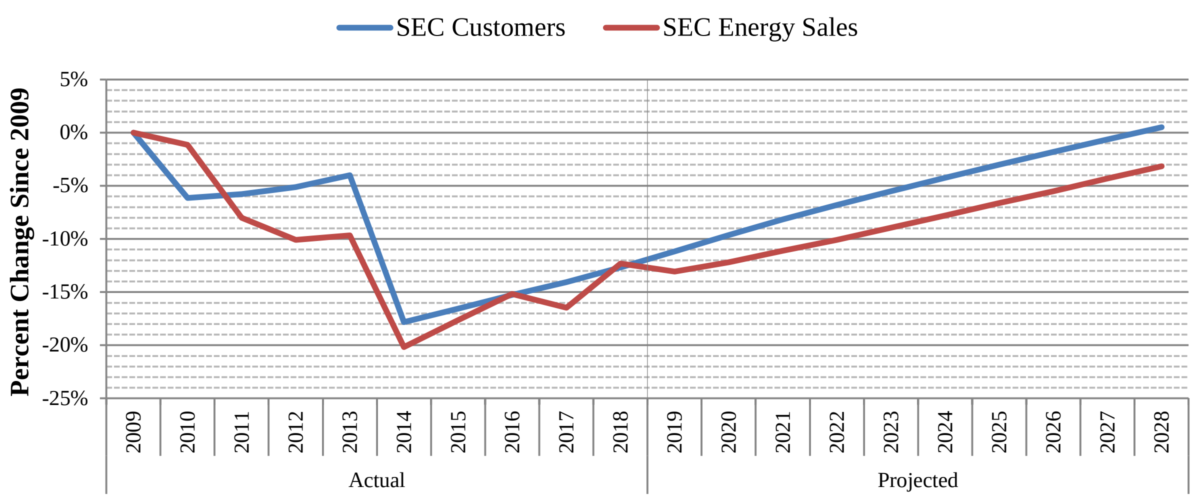
## Seminole Electric Cooperative (SEC)

SEC is a generation and transmission rural electric cooperative that serves its member cooperatives, and is collectively Florida's fourth largest utility. SEC's generation and member cooperatives are within the FRCC region, with member cooperatives located in central and north Florida. As a rural electric cooperative, the Commission's regulatory authority is limited to safety, rate structure, territorial boundaries, bulk power supply, operations, and planning. Pursuant to Section 186.801(2), F.S., the Commission finds SEC's 2019 Ten-Year Site Plan suitable for planning purposes.

### Load & Energy Forecasts

In 2018, SEC member cooperatives had approximately 787,055 customers and annual retail energy sales of 14,235 GWh or approximately 6.2 percent of Florida's annual retail energy sales. Figure 45 illustrates the Utility's historic and forecast number of customers and retail energy sales, in terms of percentage growth from 2009. Over the last 10 years, SEC's customer base has decreased by 12.66 percent, and retail sales have decreased 12.32 percent. As illustrated, SEC's retail energy sales are not anticipated to exceed its historic 2009 peak during this planning period. The decline shown in 2014 is associated with one member cooperative, Lee County Electric Cooperative, electing to end its membership with SEC.

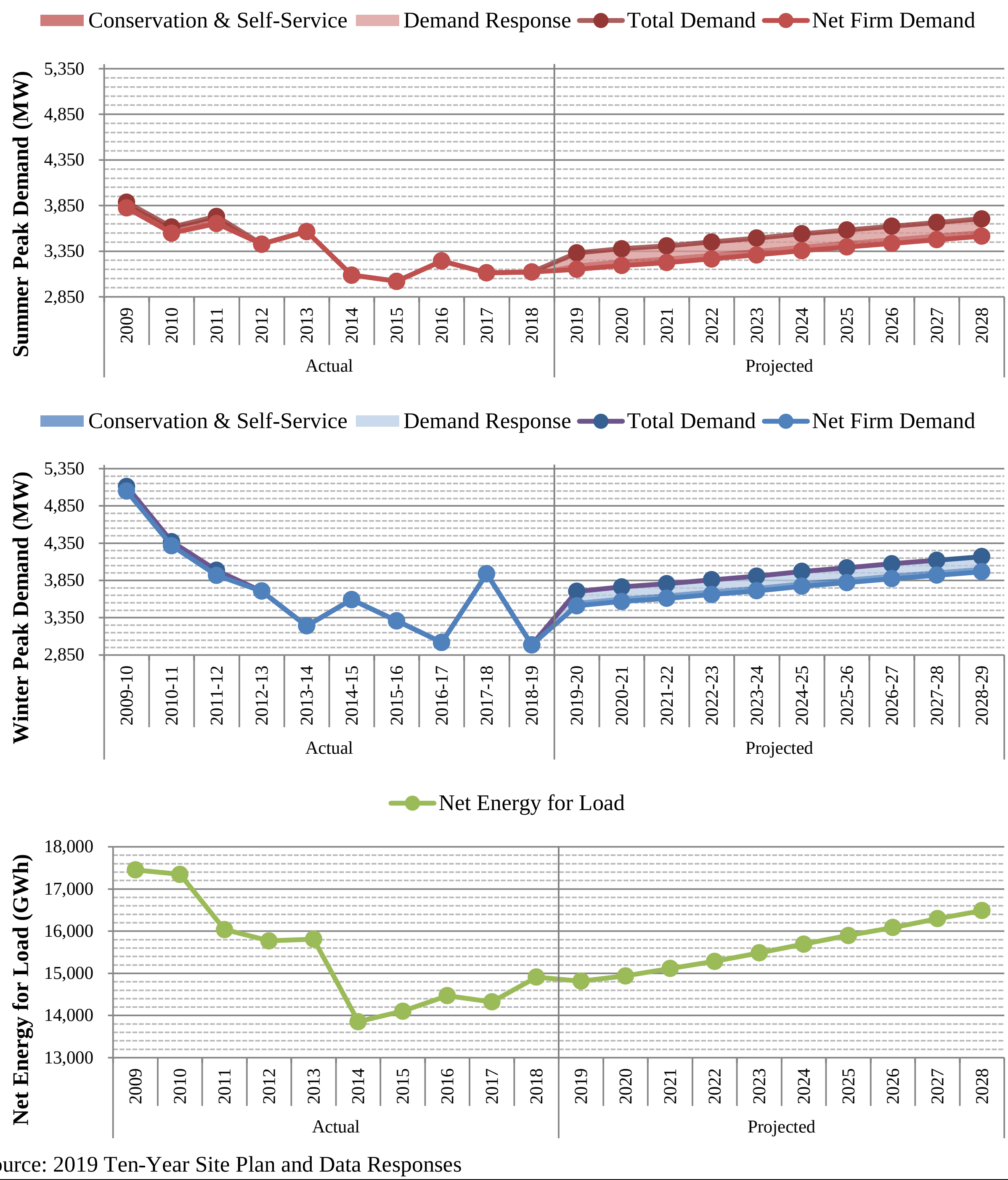
**Figure 45: SEC Growth**




Source: 2019 Ten-Year Site Plan

The three graphs in Figure 46 show SEC's seasonal peak demand and net energy for load for the historic years of 2009 through 2018 and forecast years 2019 through 2028. As SEC is a generation and transmission company, it does not directly engage in energy efficiency or demand response programs. Member cooperatives do offer demand-side management programs, the impacts of which are included in Figure 46.

**Figure 46: SEC Demand and Energy Forecasts**




Source: 2019 Ten-Year Site Plan and Data Responses

## Fuel Diversity

Table 27 shows SEC's actual net energy for load by fuel type as of 2018 and the projected fuel mix for 2028. In 2018, SEC used coal as its primary source of fuel, while natural gas was the second most used fuel. By 2028 natural gas usage is expected to become the primary fuel source.

**Table 27: SEC Energy Consumption by Fuel Type**

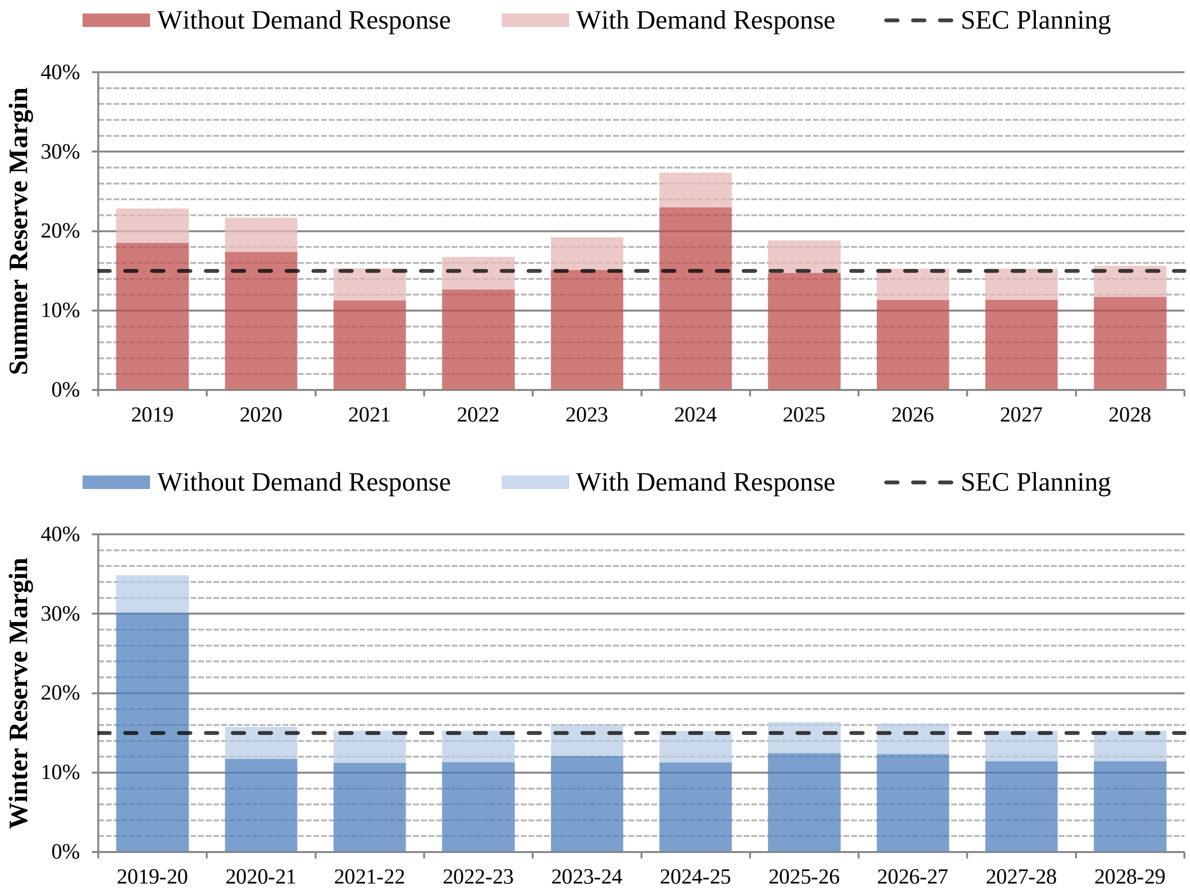
| Fuel Type | Net Energy for Load | | | |
|---|---|---|---|---|
| | 2018 | | 2028 | |
| | GWh | % | GWh | % |
| **Natural Gas** | 3,619 | **24.3%** | 9,603 | **58.2%** |
| **Coal** | 7,599 | **51.0%** | 2,839 | **17.2%** |
| **Nuclear** | 0 | **0.0%** | 0 | **0.0%** |
| **Oil** | 20 | **0.1%** | 10 | **0.1%** |
| **Renewable** | 610 | **4.1%** | 111 | **0.7%** |
| **Interchange** | 0 | **0.0%** | 0 | **0.0%** |
| **NUG & Other** | 3,064 | **20.5%** | 3,926 | **23.8%** |
| **Total** | **14,912** | | **16,489** | |

Source: 2019 Ten-Year Site Plan and Data Responses

## Reliability Requirements

SEC utilizes a 15 percent planning reserve margin criterion for seasonal peak demand. Figure 47 displays the forecast planning reserve margin for SEC through the planning period for both seasons, with and without the use of demand response. Member cooperatives allow SEC to coordinate demand response resources to maintain reliability. As shown in the figure, SEC's generation needs are determined by winter peak demand more often than summer peak demand during the planning period.

**Figure 47: SEC Reserve Margin Forecast**




Source: 2019 Ten-Year Site Plan

## Generation Resources

SEC plans to retire one unit and add one unit during the planning period, as described in Table 28. On December 21, 2017, SEC filed a need determination with the Commission for the Seminole CC Facility which was granted on May 25, 2018.[27] Consistent with its need determination filing, SEC plans to retire one of its coal-fired SGS units in 2023, and the Seminole CC Facility is expected to be in-service by 2022.

**Table 28: SEC Generation Resource Changes**

| Year | Plant Name & Unit Number | Unit Type | Net Capacity (MW) Sum | Notes |
|---|---|---|---|---|
| **Retiring Units** | | | | |
| 2023 | SGS Unit 1 or 2 | BIT – ST | 634 | Unit choice for retirement pending. Larger MW shown. |
| **Total Retirements** | | | **634** | |
| **New Units** | | | | |
| 2022 | Seminole CC Facility | NG – CC | 1,108 | Docket No. 20170266-EC |
| **Total New Units** | | | **1,108** | |
| **Net Additions** | | | **478** | |

Source: 2019 Ten-Year Site Plan

[27] Order No. PSC-2018-0262-FOF-EC, issued May 25, 2018, in Docket No. 20170266-EC, *In re: Petition to determine need for Seminole combined cycle facility, by Seminole Electric Cooperative, Inc.*

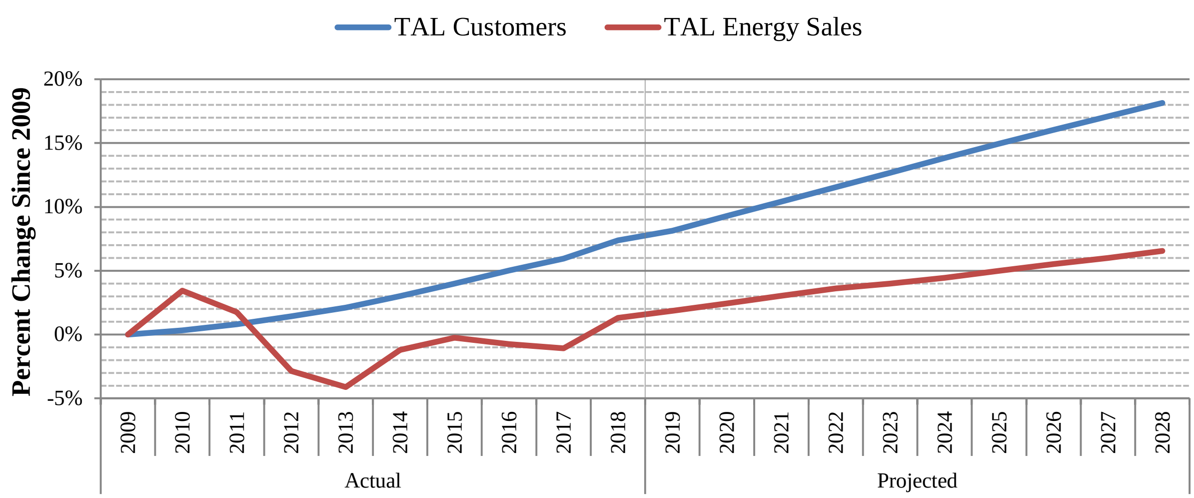
# City of Tallahassee Utilities (TAL)

TAL is a municipal utility and the second smallest electric utility which files a Ten-Year Site Plan. The Utility's service territory is within the FRCC region and primarily consists of the City of Tallahassee and surrounding areas. As a municipal utility, the Commission's regulatory authority is limited to safety, rate structure, territorial boundaries, bulk power supply, operations, and planning. Pursuant to Section 186.801(2), F.S., the Commission finds TAL's 2019 Ten-Year Site Plan suitable for planning purposes.

### Load & Energy Forecasts

In 2018, TAL had approximately 121,677 customers and annual retail energy sales of 2,698 GWh or approximately 1.2 percent of Florida's annual retail energy sales. Figure 48 illustrates the Utility's historic and forecast number of customers and retail energy sales, in terms of percentage growth from 2009. Over the last 10 years, TAL's customer base has increased by 7.39 percent, while retail sales have increased by 1.31 percent. As illustrated, TAL's retail energy sales are not anticipated to exceed its historic 2010 peak until 2022.

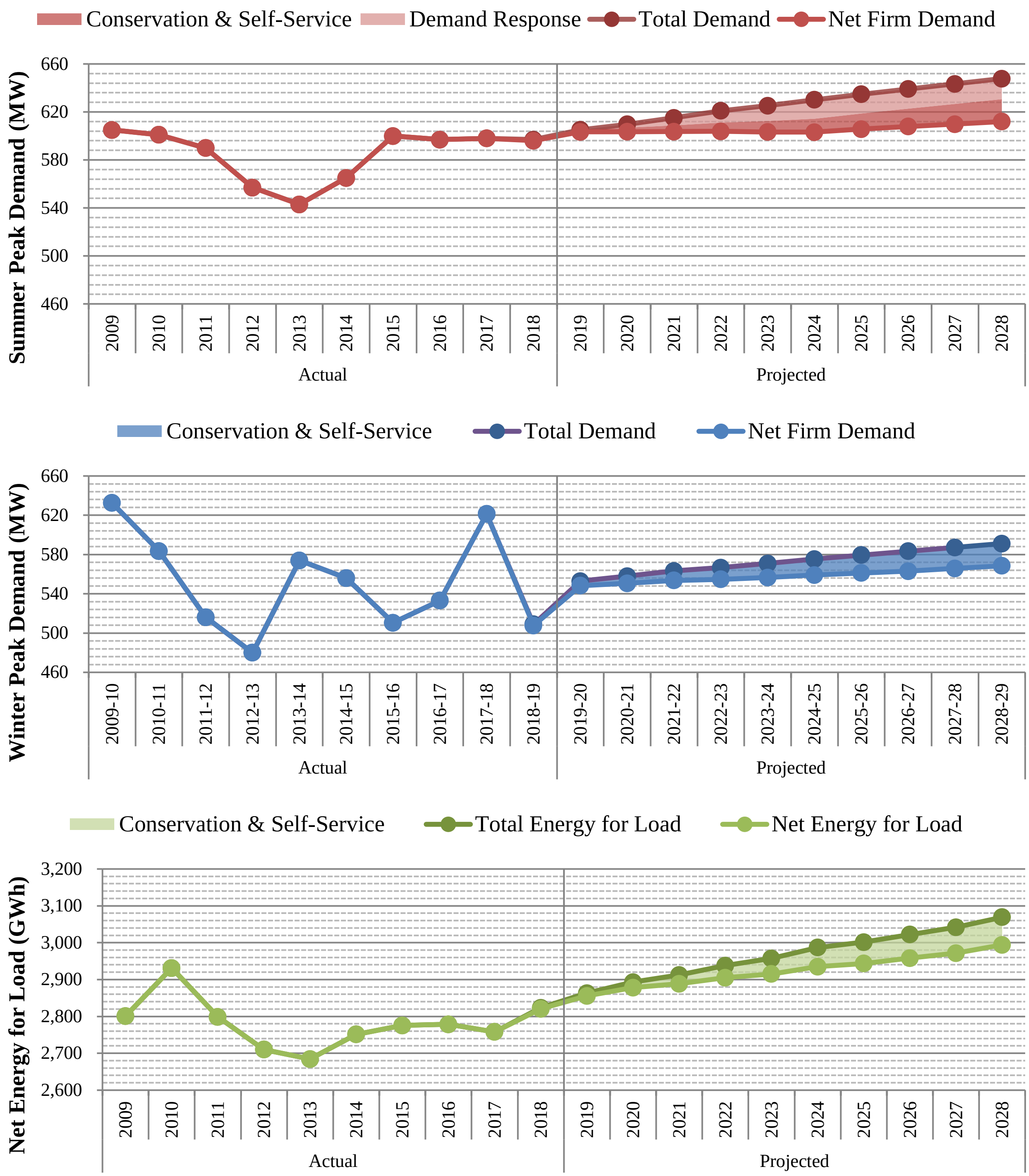
**Figure 48: TAL Growth**




Source: 2019 Ten-Year Site Plan

The three graphs in Figure 49 shows TAL's seasonal peak demand and net energy for load for the historic years of 2009 through 2018 and forecast years 2019 through 2028. These graphs include the impact of demand-side management, and for future years assume that all available demand response resources will be activated during the seasonal peak. TAL offers energy efficiency and demand response programs to customers to reduce peak demand and annual energy consumption. Currently TAL only offers demand response programs targeting appliances that contribute to summer peak, and therefore have no effect upon winter peak.

**Figure 49: TAL Demand and Energy Forecasts**




Source: 2019 Ten-Year Site Plan and Data Responses

## Fuel Diversity

Table 29 shows TAL's actual net energy for load by fuel type as of 2018 and the projected fuel mix for 2028. TAL relies almost exclusively on natural gas for its generation, excluding some purchases from other utilities and qualifying facilities and the use of oil as a backup fuel. Natural gas is anticipated to remain the primary fuel source on the system.

**Table 29: TAL Energy Consumption by Fuel Type**

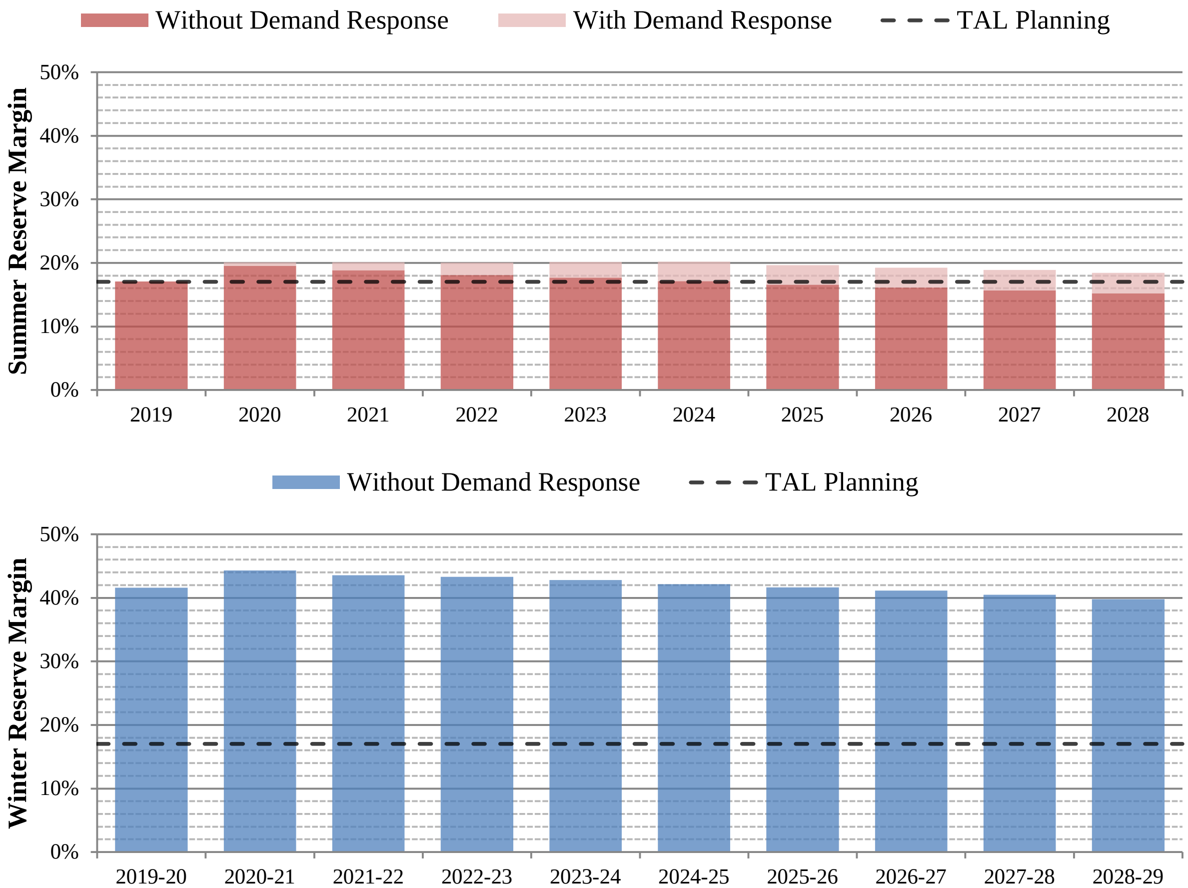
| Fuel Type | Net Energy for Load | | | |
|---|---|---|---|---|
| | 2018 | | 2028 | |
| | GWh | % | GWh | % |
| **Natural Gas** | 2,808 | **99.6%** | 2,889 | **96.5%** |
| **Coal** | 0 | **0.0%** | 0 | **0.0%** |
| **Nuclear** | 0 | **0.0%** | 0 | **0.0%** |
| **Oil** | 1 | **0.0%** | 0 | **0.0%** |
| **Renewable** | 59 | **2.1%** | 118 | **3.9%** |
| **Interchange** | -48 | **-1.7%** | -13 | **-0.4%** |
| **NUG & Other** | 0 | **0.0%** | 0 | **0.0%** |
| **Total** | **2,820** | | **2,994** | |

Source: 2019 Ten-Year Site Plan and Data Responses

## Reliability Requirements

TAL utilizes a 17 percent planning reserve margin criterion for seasonal peak demand. Figure 50 displays the forecast planning reserve margin for TAL through the planning period for both seasons, with and without the use of demand response. As discussed above, TAL only offers demand response programs applicable to the summer peak. As shown in the figure, TAL's generation needs are controlled by its summer peak throughout the planning period.

**Figure 50: TAL Reserve Margin Forecast**




Source: 2019 Ten-Year Site Plan

## Generation Resources

Table 30 shows TAL's additions and retirements over the 2019-2028 planning period. TAL plans on retiring the Corn Hydroelectric station in early 2019. On June 5, 2017, TAL filed an Application for Surrender of License for the hydroelectric station with the Federal Energy Regulatory Commission. In this filing, TAL explains its primary motivation for retiring the plant is to reduce cost and risk, the benefits from the plant's as-available energy not outweighing the costs of operation and maintenance. TAL also plans to add several natural gas-fired internal combustion units to its system from 2019-2020.

**Table 30: TAL Generation Resource Changes**

| Year | Plant Name & Unit Number | Unit Type | Net Capacity (MW) Sum |
|---|---|---|---|
| **Retiring Units** | | | |
| 2019 | Corn Hydro 1 – 3 | HY | 12 |
| **Total Retirements** | | | **12** |
| **New Units** | | | |
| 2019 | Hopkins 1 – 4 | NG – IC | 74 |
| 2020 | Hopkins 5 | NG – IC | 18 |
| **Total New Units** | | | **92** |
| **Net Additions** | | | **80** |

Source: 2019 Ten-Year Site Plan

# II. Outside Persons Who Wish to Address the Commission at Internal Affairs

**Note**: The records reflect that no outside persons addressed the Commission at this Internal Affairs meeting.

# III. Supplemental Materials for Internal Affairs

<u>**Note**</u>: The records reflect that there were no supplemental materials provided to the Commission during this Internal Affairs meeting.

# IV. Transcript

BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

PROCEEDINGS: INTERNAL AFFAIRS

COMMISSIONERS
PARTICIPATING: CHAIRMAN ART GRAHAM
COMMISSIONER JULIE I. BROWN
COMMISSIONER DONALD J. POLMANN
COMMISSIONER GARY F. CLARK
COMMISSIONER ANDREW GILES FAY

DATE: OCTOBER 17, 2019

TIME: Commenced: 9:30 a.m.
Concluded: 10:36 a.m.

PLACE: Gerald L. Gunter Building
Room 105
2540 Shumard Oak Boulevard
Tallahassee, Florida

REPORTED BY: DANA W. REEVES
Court Reporter and
Notary Public in and for
the State of Florida at Large

PREMIER REPORTING
114 W. 5TH AVENUE
TALLAHASSEE, FLORIDA
(850) 894-0828

P R O C E E D I N G S

CHAIRMAN GRAHAM: Good morning. Let the record show it is Thursday, October 17th. It is 9:30 and this is our internal affairs meeting.

Once again, we all know that it's breast cancer awareness week, which is for the most part just cancer awareness week and it's great seeing the pink shirts and ties and dresses and all that stuff out there in the audience.

It's interesting that we talk about cancer awareness. On a sad note, I didn't mention it at the last agenda because it hadn't happened at the time, but we had lost an employee of ours, Toni McCoy. She lost her battle with cancer and I wanted to give some time for the Executive Director to say a few words about her.

MR. BAEZ: Thank you, Mr. Chairman. As you said, we did lose a valued member of our family on September 19th. Actually, it had just happened after a long battle with cancer. Most of you knew Toni. She was a long-time staffer here. She joined in 1998. Over 20 years of service to the State and to this Commission. Most recently, she was with the Division of Economics. Among her many responsibilities, but the most notable is that Toni was the person that brought home the bacon for us. I mean, she was a one-woman collection agency and she did it with a great attitude. I think if you spoke to many of our smaller utilities, they would speak very, very highly of her. I want to use the word compassion, but let's say understanding and willingness to work with these small companies in order that they stay in compliance as concerns their responsibilities to the Commission.

So she always had a wonderful attitude and she did a lot of good work for us. And her positive outlook -- she came to work every day even though she was battling this. And that's an amazing and sometimes, I wish it was unnecessary, thing to be doing. She was dedicated to her work, as well as to her family. She left two children, Ian and Eve. And I just ask that you all, you know, keep her and her family in your thoughts. We will miss her. Thanks.

CHAIRMAN GRAHAM: Thank you. I know sometimes I sound like a broken record, and I thank my colleagues for giving me the latitude to take this time of personal privilege, but that's how strongly I feel about the whole issue of cancer. And, once again, let me get on my soapbox and say, this is the time we need to have these conversations. We need to talk to our families. We need to make sure we're checking ourselves out, making sure we're doing.

Okay. Let's go on to the agenda. Item No. 1, the Draft 2019 Regulatory Plan.

MS. COWDERY: Good morning, Commissioners. Staff is seeking approval of the 2019 Regulatory Plan, which reports on rulemaking in upcoming year, ending July 1st of 2020. Section 120.74 of the Florida Statutes requires the Commission to prepare this plan and submit it to the Joint Administrative Procedures Committee by October 1st of each year, publish the plan on the Commission's website and publish a notice in the Florida Administrative Register. This item had been scheduled originally for September 5th. That IA was canceled due to Hurricane Dorian. So in order to meet the requirements, the statutory requirements of filing this by October 1st, the plan was submitted to JAPC under the signatures of the Chairman and the general counsel. It was put on our website and it was published in the Florida Administrative Register. Nonetheless, staff is seeking approval of the plan. And if the Commission has any changes to make, we can file an amended plan with JAPC and publish it on our website and publish notice in the Florida Administrative Register. So, staff is available for any questions.

CHAIRMAN GRAHAM: Thank you, staff. Commissioners, you know this to be a very rare thing for myself to sign something without your approval, at least your nod, but because we are under a state of emergency and we weren't having a meeting, general counsel informed me that this is something that we can do and I, number one, didn't mean to overstep, but number two, hopefully this letter meets your approval.

MR. HETRICK: Mr. Chairman, if I could add, we viewed the filing as a formality to comply with the statute, but I certainly would like the Commission to realize that our goal here is that whatever you choose to do today is whatever you choose to do and that is equivalent of having your full voice and being able to change this plan and file a new plan, an amended plan, whatever you'd like to do we're willing and we can do under the law. So we would never otherwise have taken that extraordinary step, even in that event, had we not had any equally viable alternative to give you the full policy discretion that you exercise with regard to this regulatory plan.

CHAIRMAN GRAHAM: That all being said, any comments, questions or concerns?

COMMISSIONER FAY: And I appreciate that. I don't have any issues with the plan. The only thing I was going to ask, and this is a very small thing, is maybe you can collate them so when you go through the plans, this is upside down here when you're reading through them. I just thought that was something that maybe could be an easy change, but that shows you how good your report was. That's the thing I could find --

(Laughter.)

COMMISSIONER FAY: I mean, I appreciate it. Thank you.

MR. HETRICK: Actually, a very good point. I never saw it this way.

CHAIRMAN GRAHAM: Commissioner Brown.

COMMISSIONER BROWN: I was going to wait to give deference to the rulemaking guru over here, but with that, if there are no other comments or questions, I would move approval of the plan as submitted.

COMMISSIONER CLARK: Second the motion.

CHAIRMAN GRAHAM: It's been moved and seconded. Any further discussion? Commissioner Polmann.

COMMISSIONER POLMANN: Thank you, Mr. Chairman. I thank you, Commission Clark. You were quick out of the gate there. I was going to second.

I certainly support the procedure that was followed. I have no issue with that. I do understand under the circumstances that was appropriate to meet the deadline and I support the action that was taken. And I'm not criticizing what was done. There may have been an opportunity for this to be circulated. That would be my only comment, that that may have been an alternative, but, nonetheless, I think meeting the then-deadline was certainly the appropriate thing to do at the time.

I also have no comments with this. I think what was submitted was appropriate. So I certainly support the action that was taken. Thank you, Mr. Chairman.

COMMISSIONER GRAHAM: Okay. Any further discussion?

(No comments made.)

CHAIRMAN GRAHAM: Seeing none, all in favor say, aye.

(Chorus of ayes.)

CHAIRMAN GRAHAM: Any opposed?

(No comments made.)

CHAIRMAN GRAHAM: By your action you've approved that motion. Thank you very much.

Okay. Review of the 10-year site plan. Item No. 2.

MR. WRIGHT: Good afternoon, Commissioners. Doug Wright with Commission staff. Item No. 2 is a draft review of the 2019 10-year site plan. The review is similar in format and content to last year's review with the exception of the newly-added energy storage outlook. While projections show natural gas will continue to provide a majority share of natural -- of net energy for load through 2028, renewable resources show the largest projected growth and capacity over the next ten years, with a net increase of approximately 11,000 megawatts.

Staff would like to note three scrivener's errors in the draft before you today. On page 18, Tables 2 and 3, JEA's and GRU's column titles have been reversed. And again in Table 2, the total number of electric vehicles for the year 2019 should read 50,269 instead of 49,639. That was Table 2's year 2019 total.

At this time, staff seeks the Commission's approval of the draft review of the 2019 10-year site plan, which would find each utility's plan suitable for planning purposes and administrative leave to correct the scrivener's errors and other non-material changes prior to publication of the final version. If the Commission approves the draft, the review and attached comments will be provided to the Department of Environmental Protection for consideration of future-need determination procedures.

Staff is available for any questions.

CHAIRMAN GRAHAM: I've got a quick question. Tell me the scrivener's errors again, on page 18.

MR. WRIGHT: On page 18, Tables 2 and 3. JEA's and GRU's column title have been reversed.

CHAIRMAN GRAHAM: Okay.

MR. WRIGHT: And the third one is in Table 2. The total number of electric vehicles for the year 2019 should read 50,269 instead of the 49,639. 50,269.

CHAIRMAN GRAHAM: Okay. Number one, I want to, again, thank you guys for this report. Every year it gets better, or maybe it's just easier for me to read, the more of these things I go through, but I do appreciate the time and effort I know that goes into this. And this stuff is always very helpful because we all get questions all the time about what's going on in the State of Florida and usages of -- our IOU's and what we're doing, what we're not doing. So this is almost one of those quick go-to references and I always manage to have one in my office here and one at the house, because you can never have enough copies of this thing.

Commissioners, any questions or comments to staff about this report? Commissioner Brown.

COMMISSIONER BROWN: Thank you. I agree. The more years that pass, the more juicy the details become and you get to see all the changes that are occurring throughout the state. And I do think that there are -- you said that there's just a notable change with the natural gas from last year's forecast in your opening comments, but there are numerous notable changes from last year's presentation.

So I have a few questions on those, with regard to the growth projections on page 14 in retail sales. So it states that Florida's retail sales are anticipated to grow at 8.83 percent per year, and that's an average of all of the utilities.

MR. WRIGHT: Of the 0.83 per year? Yeah, that's over all utilities. It's looking at Florida as a whole.

COMMISSIONER BROWN: Okay. And the important reason is for load growth?

MR. WRIGHT: Could you rephrase the question?

COMMISSIONER BROWN: I just wanted to see why the increase. Is there a single factor that you can attribute that average growth? Because looking at the details in -- of each of the utilities, some have projected increases, others have declined.

MR. WRIGHT: I'm sure there's a number of factors. I guess I can defer to the forecasting expert here, Jenny.

MS. WU: Yeah, there are lots of factors to use by the utility looking at the forecast growth, including the potential weather conditions and economics, energy price and energy-efficient codes and standards.

COMMISSIONER BROWN: Do you think in this particular paragraph, because it's an average of all of the utilities -- and as I noted some show a decline while others show an increase -- do you think it would be helpful to point out the reasons for that -- that growth factor?

MS. WU: Yes.

COMMISSIONER BROWN: It's not mentioned in this paragraph.

MS. WU: Yes. In my opinion, one is triggered by -- like previous years, if we're looking at a forecast error, we present later on, on the report, the utility tend to over-forecast. And now they're kind of adjusting that. The only reason the energy efficiency -- historically they're not much embedded in the model, which leading to the over-forecast now, they realize they resolved. They kind of tend to reduce the forecast growth, which affected by more stringent-efficiency standard and customer awareness of energy saving.

COMMISSIONER BROWN: Okay. It may be helpful for staff to maybe -- because this is, you know, a provision that kind of gives a summary of the statewide perspective, to at least a few factors for that --

MR. WRIGHT: In the future we'll include the major driving factors for the --

COMMISSIONER BROWN: Yeah. Thank you.
MR. BAEZ: Commissioner, I'm sorry to interrupt. Are you looking for language similar to the top of the load forecasting section, just a sort of listing, a reminder of --
COMMISSIONER BROWN: Sure.
MR. BAEZ: -- of the various factors, something along those lines?
COMMISSIONER BROWN: Yes. Yes. Definitely. To attribute to that increase in retail sales. I mean, it's notable in Florida that there's an increase.
MR. BAEZ: There's puts-and-takes to it is really the point, but to sort of --
CHAIRMAN GRAHAM: Braulio, can I get you to turn your mic on?
MR. BAEZ: I'm sorry.
CHAIRMAN GRAHAM: That's all right.
MR. BAEZ: But sort of language along those lines --
COMMISSIONER BROWN: Yes.
MR. BAEZ: -- of the contributors?
COMMISSIONER BROWN: Yes. Absolutely. Like our Chairman was saying, having this reference handy and being able to go to that section is --

it's very, very helpful, not just now but throughout the year.

Just a few more questions. On the EV side, and I appreciate you updating us with the most accurate figures, too, is there coordination efforts being done with other state agencies on reporting? So you have a figure here of about 506,495. It's on page 17. It talks about that anticipated growth in EV's. First of all, is that number from the DMV or is that just from the IOU's?

MR. WRIGHT: So we asked directly the IOU's to report their figures, but a lot of them note that their data sources are looking at a registration of electric vehicles with Department of Motor Vehicles. So that's their data source, so kind of indirectly.

COMMISSIONER BROWN: Do we track the infrastructure that has been implemented throughout the state?

MR. WRIGHT: In terms of charging points and stuff?

COMMISSIONER BROWN: Uh-huh.

MR. WRIGHT: Yeah, we have -- that is part of the data request, but some utilities don't charge -- some utilities don't track, others do, and their projection methodologies kind of differ. So if we want our future reports, we could emphasize that, please make efforts to project and better track the charging points, but, as it is now, and as it's projected to be in 2028, penetration of electric vehicles is still pretty low in terms of the energy for load. So in terms of -- I can understand why utilities aren't prioritizing tracking.

COMMISSIONER BROWN: However, once the pilot projects expire, which some of them are set to do, I imagine that we are going to see some requests for revenue for electric vehicle infrastructure. So I think that that would be a relevant factor, at least to have a baseline of where we are in our state in terms of infrastructure.

MR. WRIGHT: Kind of like to preempt the request to get a good -- yeah, I agree. We'll include that in the future reports.

COMMISSIONER BROWN: And then the question about coordinating efforts with our other state agencies; how do we interact with the Department of Motor Vehicles on this measure?

MR. WRIGHT: Presently it's limited. We don't -- for in the efforts of this report, specifically in prior years, we haven't directly interacted with the Department of Motor Vehicles. It's mostly been a proxy through the reporting of the utilities. But, again, we can reach out to them and see if we can get a --

COMMISSIONER BROWN: How can we harness the best information for the state with the information that we have and with the information that the DMV has?

MR. WRIGHT: As of right now, I don't have a direct answer, but we can think of the methodology to kind of incorporate the reporting from the IOU's and the other municipals and then combine that with our own data collection from the DMV, and we'll get more robust projections moving forward.

COMMISSIONER BROWN: Sorry guys, just a few more. And then with regard to those pilot projects programs that have been approved by this Commission over the years, what forum will the Commission be receiving the data from those projects? Is it supposed to be here in the 10-year site plan or is it supposed to be -- looks like Mark has an answer.

MR. FUTRELL: Commissioner, certainly Duke Energy is filing -- the utilities are filing reports with us and Duke files a report with us.

We've also got some information that Gulf has filed annually with us on their activities. So there's a way to monitor that, pursuant to the rate settlement agreements that had reporting requirements. So we're looking at that.

COMMISSIONER BROWN: Can you present it to the Commission so that we know how these pilot projects are being implemented?

MR. FUTRELL: Yeah, we can provide that to you, to each office.

COMMISSIONER BROWN: Thank you. Two more questions. Sorry. So I think one of the most notable things in the 10-year site plan is the solar aspect of utility-owned renewable generation. Traditionally, the Commission has considered solar resources non-firm for planning purposes due to its intermittent nature. Can you explain why 601 megawatts now of existing utility-owned solar is considered firm in this 10-year site plan?

MR. WRIGHT: Sure. Originally when solar was first coming on the system, there was hesitation to attributing firm -- firm capacity to those units because, from an operational perspective, and it wasn't a full understanding of how they coincide with summer peak, but now since we're getting a more robust rollout of solar and the operational considerations for solar are being more understood, some utilities are now attributing a fraction of their gross capacity as firm. So it's about 27, 28 percent, all things included.

COMMISSIONER BROWN: Would the battery storage projects that you are being implemented, will that number increase once those are rolled out?

MR. WRIGHT: That is what -- we're anticipating that to be the case, but, again, they're using batteries in the different use cases. There are a lot of operational constraints in terms of if you include one 100-megawatt battery here for 74.5 megawatt solar, depending on the transmission around it and the interplay in the system and the specific utility it might not be the same, like if FPL were to include a battery or if JEA or Duke were -- you might see different firming of the solar, but definitely in some respects, we should see firming of solar with battery.

COMMISSIONER BROWN: So I think this is very notable and I think we should include that in our summary at least, because it is the first time that we're seeing it in our state for planning purposes. So I think solar being proposed for firm capacity should be highlighted, underscored in the summary. Just my opinion.

And then, finally, in the summary -- again, this is a great resource. Thank you so much for your work. The last thing. On page five, you talk about future concerns. And you only highlight one EPA rule. There are -- in the body you reference six EPA rules that affect -- that could potentially affect electric generation. I didn't know if you wanted to expand and just -- because you're just focusing on one, the ECE rule, but also if there are other future concerns, they should probably also be highlighted in that section. You've really only highlighted one. So -- and I know you say it in other places throughout the body, but that doesn't really summarize what the document says.

MR. BAEZ: Commissioner, perhaps a footnote listing?

COMMISSIONER BROWN: And probably rewording. I think it's a little sparse compared to the rest of the body. And then the -- lastly -- okay. Sorry. I had one more. The other point I think that should be underscored, at least in the letter that goes to DEP, is the renewable capacity editions that -- and you say it on page four, but I think this is very notable. Renewable capacity editions make up the majority of the projected net increase in generation capacity. That is probably the highlight of the whole package here. So I think that should be at least underscored in the letter to DEP.

MR. WRIGHT: Okay.

COMMISSIONER BROWN: Those are my comments, Mr. Chairman. Thank you guys so much for the latitude.

CHAIRMAN GRAHAM: Okay. Commissioner Polmann. Hold on a second. Do you have a comment about --

MR. BALLINGER: I just want to clarify real quick, Commissioner Brown. Several years now we haven't done formal letters to DEP and DACS. We've given them a link to our website through staff. I just wanted to -- if you all want to do a letter, we can a formal transmittal, but we haven't in the past.

I'd also like to correct Doug. I think the firm solar, this is not the first time that we've seen utilities planning for solar. It's been included -- it's roughly 50 percent of the gross rating has been a firm thing and I believe it's been going on for a couple years now.

COMMISSIONER BROWN: So it says it in -- pardon me. It does say that it's the first time on -- page 29. It does say that it's the first time that it's been deemed firm.

MR. BALLINGER: Where are you looking at? I'm sorry.

COMMISSIONER BROWN: I'll find it with all my highlights. I'll find it in a second.

CHAIRMAN GRAHAM: It's about halfway down under utility-owned renewable generation. I believe it's the fourth line.

COMMISSIONER BROWN: Capacity from these facilities have previously been considered non-firm.

MR. BALLINGER: Right. And they have in the past, but this is not the first time that they're firm. I guess maybe that's not clear in this.

COMMISSIONER BROWN: There is another spot in the document somewhere.

MR. BALLINGER: Okay. We'll look at that, but I wanted to clear that up. I think it's been two or three years now we've had -- this came about mainly from FPL's pilot programs, the first solar facilities that were installed several years ago. And the reporting of those is where we got actual data to see the coincidence with peak, where it came out to be about 50 percent. So now it's become more commonplace for utilities to include that level as a firm level.

COMMISSIONER BROWN: In the last year's 10-year site plan, we didn't have that noted.

MR. BALLINGER: I believe we did, but I'll check. I will check on that, but I wanted to -- so let us know if you want to do a letter or do it the way we've been doing, which is a transmittal, a link to the website.

COMMISSIONER BROWN: I don't have a preference. I just think that the comment that I made earlier should be underscored that -- about the increase in capacity is attributed to renewables.

CHAIRMAN GRAHAM: And also it has to be noted that capacity is only for summer peak and so you have some utilities that are winter-peak utilities and so that does not change their absolute peak, because, as we all know, there is no sunshine at six o'clock in the morning in the wintertime.

COMMISSIONER BROWN: Commissioners, Mr. Chairman, I would love to have a letter and a hard copy be delivered to DEP and any other agency that is appropriate, with your signature.

CHAIRMAN GRAHAM: Okay.

MR. BALLINGER: The two from statutes that are required are DEP and Department of Community Affairs, the energy office over there.

(Multiple speakers.)

MR. BALLINGER: Whoever the recipient is, it's changed a little bit. I think it's still Holly Burke over there, but we will do that. We can do a letter, too, if you want.

COMMISSIONER BROWN: That would be great.

CHAIRMAN GRAHAM: Commission Polmann.

COMMISSIONER POLMANN: Thank you, Mr. Chairman. With regard to that last point, I want to look over here at Commissioner Clark, since we engaged on the last item on a different point. With regard to the communication aspect of this and writing a letter, I think -- and I want to recognize Commissioner Brown's yeoman's effort here on the comments. Very extensive and I'm appreciative of that. But, given those comments and the significance of some of the items that were brought up, I think it would be appropriate to have a letter and, in fact, maybe a more extensive letter than we may have done in the past, because I know if I see a brief letter, just a transmittal letter with reference to a link, I'm not particularly inclined to look at that link unless it's something I'm -- subject matter very specifically interested in. And I think having a transmittal letter with bulleted highlights, or something else, is much more effective, and I think there is substantive material in here that is important. But you're the communications expert, or at least I deem you to be so.

COMMISSIONER CLARK: Thank you.

COMMISSIONER POLMANN: Chairman, I do have a couple of questions, but I think this is worth just one or two minutes on this issue of how do we communicate the substance of this and some of the highlights. Again, thank you, Commissioner Brown, for bringing some of these points forward. I think there are some significant points. If we can just spend a moment on mine.

COMMISSIONER CLARK: If I may, Mr. Chairman, I agree wholeheartedly. Thank you for the recommendation. I think we should definitely send a direct letter to all and I think we should probably send one to some more agencies, just as they -- there are a lot of other agencies that are taking an interest right now, especially in the renewable side, and I specifically wanted it highlighted for kind of the opposite reason, it's -- I made my feelings known in terms of solar versus -- and firm capacity. Commissioner Brown's excited that we've got to 50 percent. I'm disappointed we've only got to 50 percent. So it's the exact same information and it is good information. I think your point's right on target.

CHAIRMAN GRAHAM: Commissioner Polmann.

COMMISSIONER POLMANN: Thank you. To follow on to Commissioner Brown's comments here on growth projection statewide, if we look at page 14, 15 and both the text on the growth projections and the reference to figure seven, I'm struck by the -- we can look at either numbers or the graph -- indicates here in the text in the middle of that paragraph on page 14 on the bottom of growth projections, the current divide between customers and retail sales anticipated to be similar. And then it highlights the difference of 1.23 percent, the customers, and then the .83 percent annual. And then looking at the graph, it just jumps out at me we've got different slopes between the blue line and the red line, the number of customers growing faster than the retail sales.

And so, I immediately question, well, why is that? And does that mean that customers are becoming more energy efficient? And so if you'll look at your forecast, there's something in the forecast that suggests going forward, there's some parameter in the model is suggesting different behavior, different energy use pattern. And we don't need to go into the details today, but is there a point here in the explanation? Is there some appropriate additional explanation? Is that in the body here that I missed that maybe could be in the summary section that just says a little bit more in this section about a key point? Well, why is this? Because it's not evident in the data to date, but when you look in the forecast and say, well, those lines are divergent. So what is different going forward? So just a comment.

And then the point being, is there something else that should be said right here, just in the sentence? So I want -- like to hear what your thoughts are.

MS. WU: Yes, because from the right -- right in this report and view on this section, we do not write this. We summarize the forecast methodology and explain the forecast. And we see these portions, taking the detail we made into an explanation that you can incorporate those. Need more detail. It's our explanation why this growth rate forecast like this, into this section and --

MR. MCNULTY: Commissioner, if I could add this -- something in regards to this, this is not a new trend. This has been going on for years. And what we've seen is a considerable change in use-per-customer across classes, but specifically mostly with the residential class and mostly having to do with changes in codes and standards. That's had a big impact and building efficiency, as well. These things have been in place for years and we have been noting that for years, the change in use-per-customer and that's what you're seeing when you see that -- those diverging trend lines on the ground.

COMMISSIONER POLMANN: That's always in the forecast, but that's necessarily what we see in the actual data. I mean, if we look at the vertical line here in terms of current time, we look back as opposed to looking forward. So I'm just questioning, is that worth noting? I understand what you're saying, and that's a typical forecast.

So is that, in fact, being realized? Has it been realized as opposed to -- the projection suggests that what you said --

MR. MCNULTY: It is in the history, as well.

COMMISSIONER POLMANN: Okay.

MR. MCNULTY: It is in the history. We have seen that as codes and standards continue to change. The whole story from, you know, the change and the type of light bulbs and so forth, use-per-customer in the household has changed. And so even though we have continued customer growth, it's significant, not as great as it was prior to the 2008 -- you still have significant customer growth -- use per customer has not kept up and it's actually declined. And so that's why you have that divergence of the two lines for customers versus retail energy sales.

MS. WU: Commissioner Polmann, let my explain it here. Those trends are effect of codes and standards. While Bill just said, already experienced a notice by utilities. However, they may not necessarily embedded in the bulk of the model they use. The forecast model that they develop based on historical data over 20 or 30 years. During that years it's very --

COMMISSIONER POLMANN: Uh-huh. Sure.
MS. WU: -- lower level of codes and standards. So when the utility doing forecast use the models, they entered into the forecast variable of these so-called independent variable. That means the future potential of energy efficiency values. And then they run the model, a forecast of the future energy sales. So that means previously you may not see the forecast of the reduction of energy use in --
COMMISSIONER POLMANN: Okay. Okay.
MS. WU: -- by the model. Now made more and more show up.
COMMISSIONER POLMANN: Sure. I just want to make sure that the point that Bill is making is adequately addressed here. You're satisfied that it is. I'm --
MR. MCNULTY: We can certainly expand that point and happy to do so.
COMMISSIONER POLMANN: Yeah. Okay. And the distinction you're making, I understand that. The forecast is based on fitting the hind-cast and then bringing that forward. It doesn't necessarily take into account an estimate of this energy efficiency issue and that's fine. You're not -- you're not

fitting that into the future. It's two separate points. I'm good with that. Thank you. Thank you, Mr. Chairman.

CHAIRMAN GRAHAM: Commissioner Clark.

COMMISSIONER CLARK: Commissioner Polmann's right on target with a couple of these -- with a couple of the points, but there's a few things that go back and make up this. If you go back and look at the '70s, '80s and '90s, you want to look at historical data, and I think some of this -- it would probably be helpful to include. You look at the historical trends of how we increase the number of just appliances inside of a home. We also, we're seeing an increase in the average square footage of homes through the '70s, '80s and '90s. That trend reversed. Once we filled the homes up, let's just say the mid-'90s, we had a television in every room in the house basically. You had a dishwasher, washer, dryer, all of the modern conveniences and then you began to actually see in the early 2000's that trend kind of started reversing itself. I mean, the minimalist movement has kind of taken over and you start -- do what?

COMMISSIONER BROWN: Tiny house.

COMMISSIONER CLARK: Tiny house. The tiny house, because people are actually looking at smaller houses, less construction. You don't have the -- everybody's going to a smart device, which doesn't require the amount of power that, you know, a television in every house. Appliances become more -- all of those things combining together to begin to reduce what we were seeing as an increase, all the way probably up to 2007, an increase in KWH consumption per household. It took that massive drop from probably '08 to '10 and then started on a climb back up again, but the increase is now at a much, much smaller rate than it had been growing historically.

But the other trend that I don't see in here is one that I talked about last week, or I guess it was when we did the first review on this, was the difference in the growth rate between energy and demand. And that's probably where I see a little bit bigger concern. We're seeing an increase, the demand component is increasing at a faster rate than the energy component is. What that means is that we are -- our load factor is getting worse, which will increase the average cost per kilowatt hour that is being produced. And that's where we need to be addressing that part of the efficiency scale somewhere in the plans. Just my comments.

CHAIRMAN GRAHAM: Comments?

MR. ELLIS: To my understanding, with regard to load factor, it's usually associated with a higher residential component in Florida. And with customer choices and customer usage, it can influence that peak. I don't believe we've discussed that specifically, the growth factor here, but we do have some information about what those are. Like, we've got some charts on page 22 where it looks at both the customer -- the total amount that is the total demand of customers, as well as the contribution to demand response and conservation of that.

CHAIRMAN GRAHAM: Further questions, comments, discussions? Commissioner Fay.

COMMISSIONER FAY: Thank you, Mr. Chairman. I have a quick -- I'm probably the opposite of Chairman Graham and Commissioner Brown. The more I read this, the more questions I have. So on page four, there is a -- figure three shows the current and projected installed capacity. And so I recognize this is just speaking to the changes in the capacity, but if I'm looking at it right, it looks like at some point within the 10-year site plans that the renewable capacity will pass and exceed what the coal capacity is; is that correct?

MR. PHILLIPS: Yes, sir. That will -- according to the current plan in the 10-year site plan should happen in 2023.

COMMISSIONER FAY: That's great. Okay. Thanks. That was going to be my next question. Okay. I think that's all I had for that one.

I had another question on page 38, or something, I had marked. I am, once again -- I might be the only one who had this opinion, but when I looked at the different generating units to be retired, which I think are significant components to include in the report, when I read through the unit types, I had a lot of questions, probably not -- Commissioner Clark probably did not have these questions, but I had a question like, what bituminous or BIT is, in that chart.

So I thought maybe -- if there was some sort of legend or something that would just lay out -- because I think what's significant when you look at these different plans are, you know, natural gas or coal or whatever it may be and this seems to be getting, what these abbreviations without a legend, and the content before it doesn't really explain it either, that it just might help to include something like that in here.

Because it's -- I think it's already been said, but this gets submitted to DEP, which I presume understand and know what these are, but then also, I think, by statute goes to the Department of Agriculture and Consumer Services and others may be using this report to, you know, inform themselves, and I think the Chair and Commissioner Clark, Brown and Commissioner Polmann all said, we think this is helpful. So if it's being distributed to others, I just want to make sure it's in a format that's digestible to some people who may see stuff like that every day. Would that be feasible just to add something --

MR. PHILLIPS: We have a table prepared with the technologies, which are on the right side. For example, Table 9, we have an acronym table ready with the technologies and different fuel types. We can easily incorporate that earlier in the report. There was an acronym table for all the utilities who are -- we can incorporate a table under that one that lists all of the technology.

COMMISSIONER FAY: And that might be the easiest place to put it, because I think -- you know, you do the same thing for the utilities. It wouldn't hurt to have it there in that section and maybe even footnote or refer it back on that page so then someone can go back to it. Because I don't think you need to move all the content around to do that. I just think it would be good to have if somebody looked down there and decided they didn't know what bituminous is -- am I saying that right? Bituminous. If they didn't know what that was, they could at least flip back to it and get an explanation of it. And that's all I had. Appreciate it. Thank you.

CHAIRMAN GRAHAM: Commissioner Brown.

COMMISSIONER BROWN: Just one last question I found in my notes here that I wrote.

COMMISSIONER POLMANN: You're out of questions.

COMMISSIONER BROWN: I have a hundred more and I'm totally trying to curtail some of them. The hydro generation that's occurring in Florida, where is that occurring and which utility is generating that?

MR. WRIGHT: There -- so off the top of my head I know Tallahassee historically had hydro, but they recently forfeited that, had a plant, corn

hydro plant because it --
MR. ELLIS: They have a small facility --
COMMISSIONER BROWN: 12 megawatts.
MR. ELLIS: They're not considering that as firm capacity and that's at Lake Talquin. The other facility is at the border of Florida and Georgia. It is owned by the U.S. Army Corp of Engineers and I think it's a 50 mega -- or 45 megawatt facility.
CHAIRMAN GRAHAM: I thought we had no --
COMMISSIONER CLARK: City of Chattahoochee.
MR. ELLIS: It's a very small facility, so -- and those are the only two hydro facilities, my understanding, in the state.
COMMISSIONER BROWN: And none planned on the immediate 10-year horizon?
MR. ELLIS: No.
COMMISSIONER POLMANN: TECO had hydro 115 years ago on the Hillsborough River. Just in case you needed to know that.
COMMISSIONER BROWN: A point I will keep in my head forever. Thank you.
CHAIRMAN GRAHAM: Doc was here back then.
(Laughter.)
COMMISSIONER POLMANN: Just wanted to point

that out.

COMMISSIONER BROWN: Were you?

COMMISSIONER POLMANN: Where the water withdraw is now.

CHAIRMAN GRAHAM: Any further questions --

COMMISSIONER POLMANN: Nine feet ahead.

CHAIRMAN GRAHAM: -- concerns, comments about this 10-year report? Commissioner Brown.

COMMISSIONER BROWN: Mr. Chairman, I would move approval of the report with inclusion of the changes that have been suggested here today and give staff administrative approval to incorporate those changes, as well as give you administrative -- or executive approval of the letter that summarizes the points that were highlighted here today.

CHAIRMAN GRAHAM: Now, some of the things that were suggested today were for reports coming out in future years, not necessarily this year, but the ones that they can change in this year are the ones you're speaking of?

COMMISSIONER BROWN: Yes, sir. And also give you approval to submit the final document to whatever agencies, additional agencies, that you see fit.

CHAIRMAN GRAHAM: Okay.

COMMISSIONER POLMANN: Second.

CHAIRMAN GRAHAM: It's been moved and seconded. Any further discussion?

(No comments made.)

CHAIRMAN GRAHAM: Seeing none, all those in favor say, aye.

(Chorus of ayes.)

CHAIRMAN GRAHAM: Any opposed?

(No comments made.)

CHAIRMAN GRAHAM: By your action you've approved that motion. Thank you very much.

Legislative update. And as Adam is making his way up to the table, one of the things I wanted to tell everybody today is our Inspector General, Steve Stolting, is leaving at the end of the month. By the way, I like the shirt. He's been working in state agencies for years and years and years. He's only been here for 17 of those years, but he's going to be doing this and I specifically want to acknowledge this before the General Counsel and Executive Director spoke, because I'm sure they may have a couple words to say, as well.

Inspector General does specifically work for the Chairman, so I can tell you that he's been in and out of my office many, many, many times and a lot of times Jim is the one that kind of pushes him back out the door, but you will be missed for the work you've being doing for us and I want to say, they can stay out a year for about a year before they come back again?

MR. BAEZ: That's not going to work with me. Believe me, I tried for selfish reasons.

CHAIRMAN GRAHAM: And, actually, so whichever one of you guys is going to be chair next, I have already hired his replacement, because I thought it was important for the replacement to spend some time with Steve before Steve left, because he's a wealth of knowledge and trying to go back and read some of his old reports, you're going to miss out on some of this stuff. So I did take that leap forward and hopefully -- the person we hired was Ashley Clark from the DOT and hopefully she's going to be able to step up and fill your shoes --

COMMISSIONER BROWN: Not Gary's sister.

(Laughter.)

CHAIRMAN GRAHAM: No relation. But, Steve, you're going to be duly missed and thank you for your service.

(Applause.)

CHAIRMAN GRAHAM: Adam.

MR. POTTS: Good morning, everyone. It's getting to be that time of year, that time again. Session is early this upcoming year. It starts on January 14th. So it will be nice and cool during session. We won't have to sweat so much.

This week was the second of six committee weeks. There was one in September. There's two in October with next week also being a committee meeting -- committee week and then in November there's two and December is one. We're early in the process. So far around 600 bills have been filed. We've had bill analysis requests from the legislature that staff is working on right as we speak.

Yesterday in the House, Government Operations and Technology Appropriations Committee, Braulio presented our LBR and our plan 8B2 to the committee and did a great job. And this --

CHAIRMAN GRAHAM: Did he pay you to say that?

(Laughter.)

MR. BAEZ: I did that for free.

MR. POTTS: And then next Wednesday, just what's coming up next week so far, the committee weeks have been pretty light. A lot of our committees have not been meeting. Next week energy and utilities in the House meets for the first time and they're going to have a discussion on advanced energy technologies, and that's all they have listed, so. Yeah. We're starting to gear up. You'll hear more from us soon.

CHAIRMAN GRAHAM: Any questions, comments to add? Commissioner Fay.

COMMISSIONER FAY: Just one quick question. I watched our Executive Director present so eloquently the other day and there was a question about our budget that was presented and the vehicles that were going to be replaced, and I think they were asking about communication about maybe shared with other agencies, or how that works with DMS. I thought maybe for internal that would -- this would be a good time to just kind of ask you about that.

MR. BAEZ: Yes, Commissioner. And that question crops up every now and again, because the conversations have been going on for years in terms of a shared pool of vehicles for all the state agencies. And the question was put to us. I'm trying to remember whether it was Representative Duggan that asked the question.

COMMISSIONER FAY: Was it Dondre?

MR. BAEZ: It may have been. It may have been. They were sitting next to each other. So we've gotten that question before, the question being whether we're involved in that discussion and sort of indirectly eliciting what we thought about it. You know, my response, you know, trying to be candid with the committee, you know, we are involved in those conversations constantly. We cooperate with DMS and whatever plans they're considering and give our faithful thoughts on the matter. My opinion on it was that our usage profile for our fleet is perhaps not the -- not best lent to a shared scenario. We -- most of our vehicles are involved in carrying out our inspection function, or safety function. So they are, you know, they're down south, they're throughout the state and we do put a lot of miles on them and they're not an occasional usage by any means. They're solid. They're everyday. So I'm not sure that a shared vehicle framework would work for us specifically. There may be pieces of it that might fit, but that's a conversation that goes on regularly.

COMMISSIONER FAY: And most of that is because we have the federal mandates for the gas pipelines is now a lot of what it's --

MR. BAEZ: Well, I can't tell you now with full knowledge how that -- how that scenario might affect our responsibilities or our relationship with PHMSA. That's something that we would have to look at and obviously would come up in conversation. I mean, that could act as a limitation and I'm willing to bet that it would in realtime, but the direct answer to your question, I think, it doesn't -- there's nothing that I know of that says you can't participate on it and at this point the discussions have always been, well, is this something that might work for you.

And, like I said, that's a conversation that's persistent, that has persisted over the years on the part of DMS and other agencies. Nothing at this point has come of it and there hasn't been a meaningful step forward in making that actually a reality. At this point it's really just conversations among the agencies.

COMMISSIONER FAY: Great. That answers the question. And all joking aside, I thought you did a good job.

MR. BAEZ: Well thanks. I tried.

CHAIRMAN GRAHAM: Commissioner Clark.

COMMISSIONER CLARK: Adam, can you give us any update on the proposed 2040 energy studies? Is it taking any legs?

MR. POTTS: It has not. There's been no movement yet. It was referred to committees, but that's -- we haven't seen an agenda. The committee that it will go to first has not held a meeting yet so far. So we're in the process of working on the analysis for that. And the 2040 bill is 144 and it's a 20-year look ahead at electricity in the state and efficient ways to get it just to kind of mapping it forward, and it was filed two years ago by Senator Brandes and was never heard in committee, and they filed it again this year. So we're not sure how it's going to go.

COMMISSIONER CLARK: What is -- in the proposed bill, what is our role? Where does the PSC play a roll in the proposed bill?

MR. POTTS: It is housed within -- it's housed within the PSC and -- I can pull it up. We do have -- I believe that the OPC is the chair of the committee and the vice-chair would be appointed by -- it would be the executive director or his appointee.

CHAIRMAN GRAHAM: What is the bill?

MR. POTTS: It's Senate Bill 144. It's 2040 task force. Task force consists of the Public Counsel and his or her designee who shall serve as Chair of the Executive Director of the Public Service Commission or designee. The Chair of the Florida Energy Systems Consortium, the Chief Executive Officer of the Florida Reliability Coordinating Council, and two members of the senate and two members of the House appointed by the President and Senate -- by the President of the Senate and the House Speaker.

But the role of it is to -- is to project the state's energy needs over the next 20 years and determine how best to meet those needs in an efficient affordable and reliable manner while increasing competition and consumer choice and ensuring adequate electric reserves.

COMMISSIONER CLARK: Just wanted to make sure everyone was aware of it.

CHAIRMAN GRAHAM: Well, I have a question. I know that our secretary of agriculture had been making some comments about energy efficiency and I know other people have. Has anything been filed yet, that we know of?

MR. POTTS: No, sir, nothing has been filed and I've yet to see or hear of any language floating around.

CHAIRMAN GRAHAM: Okay. Anything else for Adam while he's here? Thanks, Adam. Thanks for your time and your report.

Okay. General Counsel report.

MR. HETRICK: Thank you, Mr. Chair, I really don't have much to report, except I would like to note that we're losing one of our attorneys. Today is her last day. Lauren Davis is leaving us. She's going back to Boston to practice, where she came from. She's been a tremendous asset to our group for the past year-and-a-half that she's been here, and we're going to miss her greatly, but I think she misses Boston and her family and friends up there and will go back to Boston to practice. Why she'd want to go to the snow country, I'm not sure but --

MR. BAEZ: Just in time for the winter.

MR. HETRICK: Yeah, just in time for the winter, but we're going to miss her greatly. So I wanted to let the Commission know that.

CHAIRMAN GRAHAM: She's probably a Patriots fan.

(Laughter.)

MR. HETRICK: You had invited me to make a few comments about Steve. I hadn't really planned to, but if I could just -- give me a minute or so. I've come to know Steve over the past couple years. I haven't personally gotten to know Steve as well as other general counsels probably have. It seems like every morning I walk in here, I have a ton of stuff and things to do to make your lives easier, but I interact with Steve, as we all do frequently, and I've come to learn the importance of the auditing and research function that he performs for this agency.

And I guess I could say that when I look at Steve, I look at someone who's extremely thorough, someone who's knowledgable, someone who's very practical in his analysis, too. He really takes the common-sense approach, as well as the theoretical. He's invaluable in a word. Often the audits he's performs are not necessarily the most exciting topics, if you will, the internal audits dealing with our internal operations, but they do lead to performance efficiency for this agencies in many years that we really don't see, but we do live it. They're also extremely fundamental to the efficient operations of this agency.

I would say Steve is fearless and ethically above reproach and also contributes enormously to the outside pristine perception and reputation of this organization, that being the Public Service Commission. Everything he does contributes to how we're viewed on the outside, because we are viewed as one of the most efficient operating agencies of any state agency.

So, you know, there's a lot that goes on behind the doors with Steve. And I can tell you, we're going to enormously miss Steve and his contribution. I hope Ashley can maybe not be able to stand in her shoes anymore than I could stand in any other general counsel shoes, but she'll continue on the legacy of high integrity and performance that Steve has made it his mission in his life here with the agency to undertake. So, Steve, thank you. And it's been a pleasure to know you and I wish you the best in your second life, because I know you're going to have a great one.

(Applause.)

CHAIRMAN GRAHAM: Keith, just look at this way, if he spent more time in your office, that means you're under suspicion.

(Laughter.)

CHAIRMAN GRAHAM: Executive Director's report.

MR. BAEZ: Well, getting business out of the way. Adam mentioned we presented our LBR and we fielded questions and I think everything went pretty smooth and we'll keep you up to date as our LBR moves through the process.

On a lighter and sadder note, I didn't know this was going to be roast Steve period, so I won't get into that, but I would echo many of the comments that were already made. To call Steve --

CHAIRMAN GRAHAM: Not to cut you off, but he doesn't leave for another two or three more weeks. We'll have an opportunity to roast him again.

MR. BAEZ: I was going to correct the record. You said the end of the month and he's leaving at the end of November and wouldn't -- meaning, he's not going to get off that easy. I won't -- I won't allow it. To say that he's just an Inspector General is short-changing everything that he's done for us, whether you know it or not as an agency, and for me personally. He is -- he has been our sanity check for many, many, many years. I am not the only one, I think, that can attest to that. And that's a great fortune for us and we're going to miss him greatly and I think the indignities will follow in due course, Steve, so be aware, but since we're going it now, I do want to extend a very public expression of gratitude for everything that you've done for this agency and I'm sure -- the one thing that I credit you most of anything is almost everything I know about the national parks I owe to that man. I owe to that man. It's not much, it's just that they exist. Right. But still, a great wealth of knowledge on all sorts of fronts. So thank you, Steve, and thank you Mr. Chairman.

CHAIRMAN GRAHAM: Yeah, I thought it was appropriate you bring it up today because his replacement's on the way in and I hate for people to sit back and say, who is that?

MR. BAEZ: We are looking forward to it. I'm very excited from executive management's perspective. Very -- as I said before, very sad to be losing a resource like Steve, but we are very pleased with your choice and we are very excited to have her on board and looking forward to working with her.

CHAIRMAN GRAHAM: Thank you. Yes. Commissioner Clark.

COMMISSIONER CLARK: For the record, who is this Steve? I've never had any meetings with the Inspector General's Office.

I did have one question for Braulio. Last year we got a generator. We had specifically requested a generator that got struck. What's the status? We were supposed to make some arrangement with DMS?

MR. BAEZ: And I've had conversations with several of you, perhaps not all of you and I apologize for that. That was an issue that we had moved forward with last budget cycle. Despite our best efforts and despite what we believe was a good solution at the time, it -- that issue ran into a little bit of static in terms of who was going to take responsibility over the funding that we were seeking. And so it got stopped. It got stuck in the mud, so to speak, last session.

The good news was that with all of that time, and because we got started so early on the issue, our fine folks in IT and the Administrative Division kept working on solutions that would achieve the goal that we were trying to achieve by pursuing the backup generation. It soon -- right around the time, as luck would have it, right around the time the budget issue got stuck, we were coming up with a technical fix that actually worked just as well and gave us our solution and probably at a much -- you know, at a fraction of the cost, to be frank. So I'm very thankful for that. So, you know, there's a sliver lining.

COMMISSIONER CLARK: The key being that we did not have access to our servers during that emergency time. So all that's been resolved?

MR. BAEZ: Yes, we believe so and we are on line, I think, as of now. So we were sort of rushing to make it so that we didn't have this persistent problem of connectivity. Most importantly, email connectivity for you, Commissioners, and the rest that needed at a time when we were, you know, taken out of the building. The last couple of years, we've lost work time or building time, let's call it, because the weather actually affected us directly. And it's those scenarios that we're trying to hedge against by pursuing this solution that ultimately didn't work out. We found a fix going through the shared resource center where we're co-locating our servers. It produces -- it keeps the connectivity so you all can check in, get email when there's communications that are maintained.

Our website us up and running putting out the reports and the information that you all have become used to seeing and the output that folks expect from us from the agency. So all of those things have been resolved without the need to be doing it on our own for our building, so -- and not to mention the added -- the added capabilities and the ease of capabilities for our folks that are in ESF12 at the time. So it was a complete solution that we're glad -- and I'm very thankful to our IT folks for keeping, you know, their nose in it and keep working for a solution and it's all worked. So thank you for the question.

COMMISSIONER CLARK: Thank you.

CHAIRMAN GRAHAM: Commissioner Brown.

COMMISSIONER BROWN: Thank you. Braulio, just one question. I know with -- we didn't have an IA in September due to Hurricane Dorian. Could you talk about some of the folks over that manned the EOC on the Commission that really worked overtime during that storm?

MR. BAEZ: Two names come to mind and the names are many. Right. And what we've tried to move, as you well know, Rick Moses leads our team there. Rick was conveniently on vacation during the time. He's starting to get the hang of this storm thing, you know.

COMMISSIONER BROWN: Any time between June 1st and November 30th.

(Laughter.)

MR. BAEZ: You know, keep an eye on that. Whenever Moses now declares a vacation time, we must all be on guard. But there is a lot of fine people who, if I start naming them, I'm going to leave somebody out.

COMMISSIONER BROWN: I just wanted to highlight, the thankless --

MR. BAEZ: They do wonderful work for us, Robert Graves and Laura King, the two point people.

COMMISSIONER BROWN: Commissioner Fay was there.

MR. BAEZ: Commissioner Fay does wonderful work.

COMMISSIONER BROWN: He does. He does.

MR. BAEZ: EOC, as well. Yes, mostly running non-interference.

COMMISSIONER BROWN: It's a very important role.

MR. BAEZ: So it's a collection of really good people, but not the least of which are utility representatives, as well. It's a group of people locked in a room, moving information left and right and facilitating restoration efforts when that's the goal and we do --

COMMISSIONER BROWN: We need to have a hot dog lunch in celebration of those folks.

MR. BAEZ: A hot dog lunch would be too little for, you know --

COMMISSIONER BROWN: Yes. Yes.

MR. BAEZ: -- not enough to show our gratitude.

COMMISSIONER BROWN: They're fantastic. I just want -- if we can recognize them a little bit more it would be great.

MR. BAEZ: Absolutely. And I vow to recognize them at every turn from here on out. Thanks again.

CHAIRMAN GRAHAM: I'm actually glad you brought that up because I wanted to thank both Commissioner Fay and Commissioner Clark because it's a lot easier for the Chairman not to have to drive over here from Jacksonville to go down to the EOC and to keep us all apprized and making decisions for the agency. I thank you both for your time.

Anything else on other matters?

(No comments made.)

CHAIRMAN GRAHAM: Okay. We are adjourned.

(Internal Affairs concluded at 10:36 a.m.)

CERTIFICATE OF REPORTER

STATE OF FLORIDA )
COUNTY OF LEON )

I, DANA W. REEVES, Professional Court Reporter, 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 28th day of October, 2019.

Dana Reeves

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DANA W. REEVES
NOTARY PUBLIC
COMMISSION #FF968527
EXPIRES MARCH 22, 2020