FILED 6/5/2024
DOCUMENT NO. 04609-2024
FPSC - COMMISSION CLERK

STONE MATTHEIS XENOPOULOS & BREW, PC

June 5, 2024

Mr. Adam Teitzman
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, Florida 32399-0850

Re: Docket No. 20240013-EG – In re: Commission review of numeric conservation goals by Duke Energy Florida, LLC

Dear Mr. Teitzman:

Please find enclosed for filing in the above-referenced docket the Direct Testimony and Exhibits of Tony Georgis on behalf of White Springs Agricultural Chemicals, Inc. d/b/a PCS Phosphate – Whtie Springs and Nucor Steel Florida, Inc. This filing is being made via the Florida Public Service Commission's Web Based Electronic Filing portal.

If you have any questions or concerns, please do not hesitate to contact me. Thank you for your assistance in this matter.

Sincerely,

/s/ James W. Brew

James W. Brew
Laura W. Baker
Sarah B. Newman
Stone Mattheis Xenopoulos & Brew, PC
1025 Thomas Jefferson St NW
Suite 800 West
Washington, D.C. 20007
(202) 342-0800
(202) 342-0807 (fax)
jbrew@smxblaw.com
lwb@smxblaw.com
sbn@smxblaw.com

Counsel for White Springs Agricultural Chemicals, Inc. d/b/a PCS Phosphate – Whtie Springs

Peter J. Mattheis
Michael K. Lavanga
Joseph R. Briscar
Stone Mattheis Xenopoulos & Brew,
PC 1025 Thomas Jefferson St NW
Suite 800 West
Washington, D.C. 20007
(202) 342-0800
(202) 342-0807 (fax)
pjm@smxblaw.com
mkl@smxblaw.com
jrb@smxblaw.com

Counsel for Nucor Steel Florida, Inc.

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a true and correct copy of the foregoing Direct Testimony and Exhibits of Tony Georgis has been furnished by electronic mail to the following parties on this 5th day of June, 2024:

Duke Energy
Matthew R. Bernier/Stephanie A. Cuello/Robert Pickels
106 E. College Avenue, Suite 800
Tallahassee FL 32301
FLRegulatoryLegal@duke-energy.com
matthew.bernier@duke-energy.com
stephanie.cuello@duke-energy.com
Robert.Pickels@duke-energy.com

Florida Department of Agriculture and Consumer Services
Erik Sayler/Brooks Rumenik
The Mayo Bldg, Suite 520
Tallahassee FL 32399
Erik.Sayler@FDACS.gov
Brooks.Rumenik@fdacs.gov

Spilman Law Firm
Steven W. Lee
1100 Bent Creek Boulevard, Suite 101
Mechanicsburg PA 17050
slee@spilmanlaw.com

Spilman Law Firm
Stephanie U. Eaton
110 Oakwood Drive, Suite 500
Winston-Salem NC 27103
seaton@spilmanlaw.com

Southern Alliance for Clean Energy
William C. Garner
3425 Bannerman Rd. Unit 105, No. 414
Tallahassee FL 32312
bgarner@wcglawoffice.com

Duke Energy
Dianne M. Triplett
299 First Avenue North
St. Petersburg FL 33701
Dianne.triplett@duke-energy.com

Florida Industrial Power Users Group
Jon C. Moyle, Jr./Karen A. Putnal
c/o Moyle Law Firm
Tallahassee FL 32301
jmoyle@moylelaw.com
kputnal@moylelaw.com

Earthjustice
Bradley Marshall/Jordan Luebkemann
111 S. Martin Luther King Jr. Blvd.
Tallahassee FL 32301
bmarshall@earthjustice.org
jluebkemann@earthjustice.org

Office of the General Counsel
Adria Harper/Jacob Imig/Jonathan Rubottom
aharper@psc.state.fl.us
jimig@psc.state.fl.us
jrubotto@psc.state.fl.us

/s/ Laura Wynn Baker
Laura Wynn Baker

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Commission review of numeric Conservation goals by Duke Energy Florida, LLC.	**))))**	**DOCKET NO. 20240013-EG**

DIRECT TESTIMONY OF TONY GEORGIS

ON BEHALF OF WHITE SPRINGS AGRICULTURAL CHEMICALS, INC. D/B/A PCS PHOSPHATE – WHITE SPRINGS AND NUCOR STEEL FLORIDA, INC.

JUNE 5, 2024

TABLE OF CONTENTS

EXHIBITS

I. INTRODUCTION AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS, AND CURRENT EMPLOYMENT POSITION.

A. My name is Tony M. Georgis. I am the Managing Director of the Energy Practice of NewGen Strategies and Solutions, LLC ("NewGen"). My business address is 225 Union Boulevard, Suite 450, Lakewood, Colorado 80228. NewGen is a consulting firm that specializes in utility rates, engineering economics, financial accounting, asset valuation, appraisals, and business strategy for electric, natural gas, water, and wastewater utilities.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING?

A. I am testifying on behalf of White Springs Agricultural Chemicals, Inc. doing business as PCS-Phosphate – White Springs ("PCS") and Nucor Steel Florida, Inc.

Q. PLEASE OUTLINE YOUR FORMAL EDUCATION.

A. I have a Master of Business Administration degree from Texas A&M University with a specialization in finance. Also, I earned a Bachelor of Science in Mechanical Engineering from Texas A&M University. In addition to my undergraduate and graduate degrees, I am a registered Professional Engineer in the states of Colorado and Louisiana.

Q. PLEASE DESCRIBE YOUR PROFESSIONAL EXPERIENCE.

A. I am the Managing Director of NewGen's Energy Practice. I have more than 25 years of experience in engineering and economic analyses for the energy, water, and waste resources industries. My work includes various assignments for private industry, local governments, and utilities, including sustainability strategy, strategic planning, financial and economic analyses, cost of service and rate studies, energy efficiency, and market research. I have been extensively involved in the development of unbundled cost of service and pricing models during my career. A summary of my qualifications is provided within Exhibit TMG-1 to this testimony.

Q. HAVE YOU TESTIFIED BEFORE ANY REGULATORY COMMISSIONS?

A. Yes. I have submitted testimony to the California Public Utilities Commission, the Public Utility Commission of Texas, the Florida Public Service Commission ("Commission"), and the Indiana Utility Regulatory Commission, as shown in my resume and record of testimony included as Exhibit TMG-1.

Q. WAS YOUR TESTIMONY PREPARED BY YOU OR UNDER YOUR DIRECT SUPERVISION?

A. Yes, it was.

II. SUMMARY AND RECOMMENDATIONS

Q. WHAT IS THE PURPOSE AND SCOPE OF YOUR DIRECT TESTIMONY?

A. Duke Energy Florida, LLC ("Duke" or "DEF") has filed its DSM goals for the period of 2025–2034 for the Commission review and approval in this docket. Duke recommends setting its goals based on a portfolio of DSM programs that it determined are cost effective based on the Rate Impact Measure ("RIM"), Total Resource Cost ("TRC"), and Participant Cost Tests ("PCT"). The portfolio of programs is primarily based on RIM test results. However, DEF also recommends measures passing the TRC test, and the addition of low-income measures that may not meet cost-effectiveness tests but otherwise are appropriate to include.[1] Included in the DEF testimony is a proposal to change the existing Interruptible General Service ("IS") and Curtailable General Service ("CS") credit rates. However, the actual CS and IS credit rates are proposed in DEF's concurrently pending general base rate case (Docket No. 20240025-EI, the DEF "Base Rate Case"). My testimony explains why, in the context of setting DEF's five-year DSM conservation goals, the Commission should reject DEF's proposed reduction in CS and IS credits since both programs remain cost-effective.

First, my testimony explains that DEF's Ten-Year Site Plan and the embedded costs reflected in its Base Rate Case capture the historical and ongoing CS and IS capacity benefits. However, the Conservation Goals Case only evaluates DEF's proposed incremental DSM conservation goals based on a forward-looking assessment of technical and economic potential. Since DEF's proposed changes to CS and IS credits apply to both existing and new program participants, DEF's cost-effectiveness measures, and particularly the RIM test, systematically understate the value historically DEF has realized by these programs. Second, my testimony explains how DEF's chosen avoided cost generating unit does not reflect the utility's actual planned additions and retirements to its portfolio. Thus, it understates the value of DEF's proposed DSM programs. Finally, in light of the above-described issues, I recommend a refined and reasonable approach for estimating DEF's avoided capacity costs for this cycle.

[1] Direct testimony of Tim Duff on behalf of Duke Energy Florida, LLC at 12-13.

Q. PLEASE DISCUSS THE OVERLAP BETWEEN DUKE'S CONSERVATION GOALS AND BASE RATE CASES.

A. CS and IS are distinct electric rate tariffs offered by DEF, and some form of these tariffs has been in effect for decades. The rates, credits, and terms and conditions of service under these tariffs are determined in DEF base rate cases. In my experience, most utilities typically offer some type of interruptible or non-firm service to their large commercial and industrial customers that provides recognized system reliability benefits, reduction of capacity costs, or both, and the rates, terms and conditions of that service are typically addressed in the utility's base rate cases. Further, DEF routinely recognizes the CS and IS benefits in its annual Ten-Year Site Plan filings (i.e., DEF reduces net firm load and generation reserve margin requirements for resource planning purposes by the CS and IS capacity reductions amounts). The outcomes of the Ten-Year Site Plans are then integrated into the General Rate Case as generation infrastructure investments and related costs.

At the same time, DEF's CS and IS are considered DSM measures. Consequently, the costs and revenues associated with these and other DSM measures are addressed in DEF's Energy Conservation Cost Recovery ("ECCR") clause proceedings. By evaluating only the cost effectiveness of incremental new DSM measure capacity reductions and benefits, DEF's evaluations in this docket disregard historic and ongoing system benefits provided by the large CS and IS program participants. In addition, DSM measure evaluations submitted in the Conservations Goals Case do not attempt to address certain critical program requirements and elements, including the terms and conditions associated with CS and IS service (e.g., when and how Duke can interrupt service, how much advance notice to curtail is provided [if any], potential outage frequency and duration) that are material elements affecting the benefit of the service to DEF, and the real costs (e.g., protocols for interruption events, production losses, increased maintenance, opportunity costs) that a participant must consider to enroll or remain in these programs. Thus, the credits for CS and IS service, as well as all other rates, terms and conditions, should be decided in a base rate case.

Q. WHAT IS YOUR RECOMMENDATION REGARDING THE COORDINATION OF THE BASE RATE AND CONSERVATION GOALS CASES?

A. To rationally reconcile these two regulatory proceedings, Duke needs to provide the projected cost effectiveness of the CS and IS programs in this Conservation Goals Case, but all proposed changes to the tariff rates, credits, and terms and conditions of service should only be addressed in DEF Base Rate Cases where all rates, credits, and terms and conditions of service can be considered.

Q. PLEASE SUMMARIZE YOUR TESTIMONY AND RECOMMENDATIONS.

A. My recommendations are as follows:

- **<u>The Commission Should Consider the Ongoing Value of Existing IS and CS Participation When Establishing DEF's Demand Response Goals:</u>**

Of the cost-effectiveness tests DEF performs, the TRC best reflects the overall value of a DSM measure to the utility system and all ratepayers. With TRC results of 16.3 for IS service and 35.1 for CS, these demand response programs have long been among the most cost-beneficial of all the Duke DSM measures.[2] The historical and ongoing value provided by the CS and IS programs to Duke is realized in reduced transmission and generation investments that are embedded in DEF's historical cost of service. This historical contribution to avoiding needed investments and ongoing benefits provided by current program participants is assumed as a given and not considered in DEF's filings in the Conservation Goals Case. DEF's proposal to adjust and reduce CS and IS credits based on outdated RIM results and disregarding the exceptionally favorable TRC results shown in DEF's own testimony, is unreasonable.

- **<u>Realistic Avoided Capacity Cost Assumptions Should Be Adopted for Application in the Conservation Goals Case:</u>**

Duke's cost-effectiveness tests are premised on a brownfield combustion turbine ("CT") in its estimate of the marginal generation costs avoided by its DSM programs.[3] There are flaws in the DEF cost estimate that materially understate the benefits of all demand response measures. Moreover, in selecting a brownfield CT as its avoided generation unit, Duke disregards how it is actually investing in and changing its generation portfolio. I recommend that a more realistic estimate of avoided costs be adopted based on updated industry estimates of the cost of a greenfield CT.

Q. WHAT ARE THE RESULTS OF YOUR RECOMMENDATIONS WHEN IMPLEMENTED?

A. The results of my recommendations are as follows:

---

[2] DEF Exhibit TD-8 (Duke Energy Florida's Cost-effectiveness Tests for all DSM Programs in TRC Portfolio).

[3] DEF Exhibit TD-4 (Duke Energy Florida's Avoided Generation Assumptions).

- Based on the exceptional TRC results that DEF estimates apply to the CS and IS service, the Commission should not assume or adopt any downward adjustment in the prevailing CS and IS credits and program costs in establishing DSM goals for DEF in this docket.
- The Commission should adopt the updated and more realistic CT avoided cost estimate described in my testimony and should find that both CS and IS service are cost effective when viewed from both RIM and TRC tests.

Q. WHAT EXHIBITS ARE YOU SPONSORING?

A. I am sponsoring the following Exhibits:

- TMG-1 Resume and Record of Testimony of Tony Georgis
- TMG-2 Select Duke Responses to Interrogatories
- TMG-3 Select Duke Curtailable and Interruptible Service Tariffs
- TMG-4 Duke Energy Florida, LLC's 2024 Ten-Year Site Plan
- TMG-5 Progress Energy Florida, Inc.'s 2005 Ten-Year Site Plan

III. <u>CURTAILABLE AND INTERRUPTIBLE SERVICE CREDITS VALUE CALCULATIONS</u>

Q. PLEASE DESCRIBE DUKE'S CURRENT CS AND IS PROGRAMS.

A. The CS and IS service programs are important and long-standing DEF demand response programs. They are electric system reliability programs, which means that for IS service, DEF can interrupt service to all of a participating customer's load any time there is a system emergency that threatens service to Duke's firm service customers.[4] The DEF CS and IS programs have been in place for decades and have benefited Duke and its firm service customers by allowing them to avoid the construction of generation peaking units during that time.

IS customers must provide interruptible capacity with no limit on the number of interruptions by Duke. These interruptions may occur with little or no effective warning and will last as long as DEF requires to ensure continued reliable service to its firm retail loads.[5] DEF has designed the IS tariff to ensure that it can count on the committed load reduction in its resource planning. IS customers must commit the interruptible capacity for five-year contractual periods and must give three years of advanced notice to exit the program. CS service contains the same requirements as IS with the exception of two-year contract commitments instead of five years. However, if the CS customer transfers from a curtailable to a firm service offering, they must provide at least 36-month prior written notice to Duke, which effectively makes the CS commitment three years, not two. Integration of the CS and IS capacity in DEF's resource planning is documented in its Ten-Year Site Plan.[6]

It is important to note that interruption calls by DEF to IS participants are not limited under the tariff to the system peak hours, but could occur at any time that there is a

---

4 *See* Exhibit TMG-3 at page 12 of 14 (Rate Schedule IST-2, DEF Tariff Section No. VI, Twenty-Ninth Revised Sheet No. 6.265).

5 *Id.*

6 *See* Exhibit TMG-4 at page 33 of 135 (Schedule 3.1.1).

system need.[7] This form of non-firm service constitutes a virtual peaking or black-start generation unit. Duke controls the IS customer's electric disconnect switches; thus, the load reduction is effectively 100% reliable and available. CS service interruptions function nearly identically to the IS service except that the customer controls their load reduction.[8]

Q. HOW DOES THE VIRTUAL PEAKING CAPACITY PROVIDED BY THE CS AND IS PROGRAMS COMPARE TO DEF'S EXISTING PEAKING GENERATION UNITS?

A. Currently, Duke CS and IS participants provide approximately 402 MW of almost immediately available demand reduction.[9] This highly reliable and available capacity reduction associated with the CS and IS programs is in contrast to the aging fuel-oil peaking CTs currently in DEF's generation portfolio which are rarely called upon to operate and which DEF has targeted for retirement due to their age, expense to run, and limited dispatch capability.[10] The reduced capacity need resulting from CS and IS load allows DEF to avoid the costs of constructing peaking generation in addition to other costs such as associated land costs, property taxes, siting and permitting costs, spare parts, startup testing, depreciation, dismantlement and decommissioning costs, and the costs and risks associated with failed startups that may occur with DEF's older CTs. These system benefits are the reason that CS and IS service have perennially exhibited

---

[7] Exhibit TMG-3 at page 9 of 14 (Rate Schedule IS-2, DEF Tariff Section No. VI, Thirtieth Revised Sheet No. 6.255).

[8] *See, e.g.*, *id.* at page 3 of 14 (Rate Schedule CS-2, DEF Tariff Section No. VI, Twenty-Ninth Revised Sheet No. 6.237).

[9] Exhibit TMG-2 at pages 1-2 of 6 (Duke Response to PCS Third Request for Interrogatories No. 11).

[10] *See* Exhibit TMG-4 at page 47 of 135 (Schedule 6.1).

among the highest TRC values of all Duke DSM measures. resulting in a benefit / cost ratio of 16.3 for IS and 35.1 for CS in the current Conservation Goals Case. These results are 300% to 700% higher than DSM measures targeting other retail customer segments.[11]

As discussed, Duke has complete control over the service interruption to participating IS customers, and there is no opportunity for a participating customer to avoid, or "buy through," any service interruption. Also, it is important to note is that in addition to DEF's ability to call CS and IS load reductions at any time and for any system reliability reason, the IS interruptible capacity requirements are valuable to DEF as they are instantaneous compared to required start time and ramp rate limitations of its CTs. The customer load reduction performance under the IS tariff is superior to CTs as it requires an immediate response time controlled by DEF. The result of these CS and IS tariff conditions and terms of service is an extremely reliable and flexible emergency resource for DEF built on exceptionally stringent and inflexible performance requirements for participating loads.

Q. HOW DOES DUKE ACCOUNT FOR THE CS AND IS LOADS IN ITS GENERATION RESOURCE PLANNING AND TEN-YEAR SITE PLANS?

For resource planning purposes, Duke has not in the past and does not currently treat the full measured demand and loads of CS and IS customers as firm loads that must be served by its generation resources. This is clearly documented and calculated in the Ten-Year Site Plan filings, which deduct the CS and IS capacity values from the

---

[11] DEF Exhibit TD-8 (Cost-effectiveness Tests for all DSM Programs in TRC Portfolio).

determination of Net Firm Demand upon which Duke calculates its capacity reserve margins and generation capacity requirements.[12] In the 2024 Ten-Year Site Plan, Duke cites 402 MWs of available interruptible capacity reductions to the Net Firm Demand requirements for 2024 and realized between 232 to 476 MWs of capacity reductions in the last 10 years.[13] Based on the past Ten-Year Site Plans, CS and IS participants have provided a continuous source of avoided generation capacity need, system reliability benefits, and cost savings to Duke and all firm service customers for multiple decades.[14]

Q. WHAT IS THE TOTAL CAPACITY NEED THAT DUKE HAS AVOIDED THROUGH THE CS AND IS PROGRAMS?

A. Duke's generation and transmission systems are designed and constructed to meet expected net firm peak demands on the utility system plus a reserve margin. The CS and IS programs have allowed Duke to avoid or defer additional transmission and generation investments over the years in which the programs have been active.

In Florida and for Duke, the accepted capacity reserve margin for resource planning purposes is 20%.[15] Thus, the capacity benefit provided by CS and IS participants includes the contracted and dedicated capacity reductions of 402 MWs as previously noted plus the associated reduction in required reserve margin. For example, as 402

---

12 Exhibit TMG-4 at 33 of 135 (Schedule 3.1.1).

13 *Id*.

14 *See, e.g.*, Exhibit TMG-5 at pages 30-32 of 102 (Progress Energy Florida, Inc.'s 2005 Ten-Year Site Plan).

15 Exhibit TMG-4 at page 112 of 135.

MWs are available for CS and IS capacity reductions in the 2024 Ten-Year Site Plan, the actual benefit to Duke including the 20% reserve margin is 482 MWs.[16]

Q. ARE THESE HISTORIC AVOIDED COST BENEFITS CONSIDERED IN THE CONSERVATION GOALS PROCEEDINGS?

A. No. In fact, DEF witness Herndon assumed continued existing CS and IS participation as a given remaining at current levels (*i.e.* he did not assess the benefits provided by current participants, but simply presumed that current levels of participation continue).[17] The system benefits provided through the years by existing program participants are, however, effectively captured in DEF's Base Rate Case proceeding through embedded generation and transmission costs that are shown in its cost of service analysis. These production and transmission costs in the DEF Base Rate Case are reduced because of CS and IS participation.

In short, looking only at marginal future program benefits, as DEF does in its DSM Goals filing, does not accurately capture the benefits DEF actually realizes from the programs. In the context of this docket, this helps to explain why there is a such a dramatic disparity between RIM and TRC cost/benefit calculations for these programs. DEF correctly proposes to continue the highly successful CS and IS programs, but its proposal to change the level of credits based solely on outdated RIM results, is

---

[16] 402 MW x 120% = 482.4 MW

[17] *See* Exh. TMG-2 at page 5 of 6 (DEF's Response to PCS Phosphate's Fifth Set of Interrogatories (No. 17)).

inappropriate. It is important to note that DEF's projection of DSM program costs through the year 2030 assumes no reduction in CS or IS incentive payments.[18]

Q. PLEASE EXPLAIN FURTHER.

A. Duke's approach calculates avoided future costs to assess projected benefits to incremental new program participation, but then applies that estimated marginal benefit to both existing and future participation when existing participants are contractually committed through the multiple test years of the pending Base Rate Case. In addition to the avoided cost calculation errors described below, excessive reliance on the RIM test for setting program goals largely disregards the significant and on-going system benefits that are recognized in the TRC test.

Q. HOW SHOULD THE VALUE OF CS AND IS SERVICE BE RESOLVED?

A. The solution should be twofold.

- First, for the purpose of setting DEF's DSM goals for the coming cycle, the RIM and TRC tests are equally relevant for the Duke CS and IS programs. Looking at both measures, it is apparent that both measures are highly cost-effective and beneficial and no reduction in the existing credits should be assumed.
- Second, any prospective adjustment to CS and IS credits should be determined in DEF Base Rate Cases where all other elements of the rates and terms and conditions of those tariffs are evaluated and approved.

---

[18] *Id.*

IV. AVOIDED CAPACITY COSTS ASSUMPTIONS

Q. HOW DOES DUKE USE AVOIDED COSTS FROM DSM PROGRAMS IN ITS CONSERVATION GOALS RECOMMENDATIONS?

A. Duke's Conservation Goals proceeding and recommendation of programs utilize cost/benefit analyses premised upon future benefits of avoiding marginal new capacity costs. Duke elected to calculate that avoided marginal generation cost based on the construction of a brownfield natural gas CT entering commercial service in 2029. Duke estimates the avoided generating unit costs for the construction of a brownfield CT at $735.20 per kilowatt ("kW") which includes transmission interconnection costs.[19]

Q. IS DEF'S SELECTION OF A BROWNFIELD CT ENTERING SERVICE IN 2029 REPRESENTATIVE OF ITS AVOIDED GENERATION CAPACITY COSTS?

A. No. DEF's most recent 2024 Ten-Year Site Plan reveals that over the next five years the utility plans significant capacity additions, none of which involve new CTs. In fact, DEF's basic plan, as noted above, involves retiring more than 500 MWs of existing oil-fueled CTs that are older, expensive to run, and maintain and operate at exceptionally low capacity factors.[20] Duke plans to replace that capacity with 14 solar projects comprising more than 1,000 MWs of nameplate capacity as well as uprates to its gas-fired combined cycle facility capacity.[21] Because all the planned individual solar projects are rated at less than 75 MWs, there will be no finding of a capacity need by

19 DEF Exhibit TD-4 (Duke Energy Florida's Avoided Generation Assumptions).

20 Exhibit TMG-4 at page 69 & 75-76 of 135 (Schedule 8).

21 *Id.*

the Commission for those resources per Section 403.503(14), Florida Statutes. In short, DEF's actual avoidable generation investment lies in its significant new generation additions over the next five years, and the more than 400 MWs of existing CS and IS demand response effectively support the retirement of the older oil-burning CTs through lowering DEF's reserve margin requirements.

Q. WHAT OTHER ISSUES HAVE YOU IDENTIFIED WITH DUKE'S FUTURE AVOIDED COSTS ASSUMPTIONS?

A. Duke's assumption of a brownfield CT for avoided generation capacity selects the cheapest resource to be built on the DEF system over the next decade while disregarding the billions in other capacity additions that it plans to make. Additional energy efficiency and demand response should be far more cost effective for DEF ratepayers than the other fossil-fueled and non-fossil-fueled generation included in the Ten-Year Site Plan, such as limited summer capacity additions attributed to the solar additions.

Q. IS THERE A DIFFERENCE IN THE CAPITAL COSTS, AND THUS THE AVOIDED COSTS, ASSOCIATED WITH THESE FOSSIL-FUELED AND NON-FOSSIL-FUELED RESOURCES IDENTIFIED IN DUKE'S TEN-YEAR SITE PLAN?

A. Yes. As shown below, the potential avoided costs of the generation resources Duke uses to meet its load and required 20% reserve margin vary significantly.

- Brownfield CT $735.20 per kW[22]
- Greenfield CT $949.40 per kW[23]
- Solar $1,222 per kW[24]
- Storage $1,650 per kW[25]
- Solar with Storage $2,471 per kW[26]

Q. WHAT IS YOUR RECOMMENDATION FOR DEF'S AVOIDED GENERATING UNIT COSTS IN THE CONSERVATION GOALS CASE?

A. To reconcile the significant disconnect between DEF's claimed avoided unit in this docket and the proposed generation investments over the next five years, I recommend that DEF treat its avoided unit for the purposes of the Conservation Goals Case as a greenfield CT beginning operation in 2027, which is the year the last Debary distillate oil CT is scheduled to retire. Rather than treat the planned solar additions or combined cycle unit costs as the avoided unit, an approach using a greenfield CT would be an appropriate compromise and would align with other utilities' avoided generation unit costs.

---

22 DEF Exhibit TD-4 (Duke Energy Florida's Avoided Generation Assumptions).

23 *Id.*

24 Exhibit TMG-4, page 77 of 135 (Mule Creek Commercial in-service date of 3/2024).

25 *Id.* at page 87 of 135 (TBD Battery Storage in-service date of 3/2027).

26 *Id.* at page 91 of 135 (TBD Photovoltaic with Battery Storage in-service date of 7/2028).

Q. DO OTHER FLORIDA UTILITIES UTILIZE A SIMILAR GENERATION UNIT IN THEIR ASSUMPTION OF AN AVOIDED GENERATION UNIT COST?

A. Yes. Tampa Electric ("TECO") utilizes a natural gas-fired reciprocating engine for its avoided unit data in its Conservation Goals proceeding. TECO estimates the costs for the avoided generation unit at $1,278.92 per kW, which is 74% higher than Duke's brownfield CT assumption.[27] In addition, Florida Power and Light's ("FP&L") estimate for an avoided generation unit in its Conservation Goals proceeding is based on a combined-cycle ("CC") unit.[28] I estimate the construction cost of such a unit to be $1,221 per kW using National Renewable Energy Laboratory ("NREL") Annual Technology Baseline report.[29]

Q. WHAT ARE REASONABLE ASSUMPTIONS CONCERNING THE EXPECTED COST OF A GREENFIELD CT FOR DUKE?

A. Duke's Conservation Goals Case identifies the capital costs for construction of a greenfield CT at $949.40 per kW in 2034.[30] Further, this estimate is in line with the current NREL's Annual Technology Baseline report which assesses normalized

---

[27] Docket No. 20240014-EG, *In re: Commission review of numeric conservation goals of Tampa Electric Company*, Exhibit No. MRR-1 Document No. 10, p. 1 of 1.

[28] Docket No. 20240012-EG, *In re: Commission review of numeric conservation goals of Florida Power & Light Company*, Direct Testimony of Andrew Whitley on behalf of Florida Power & Light Company, p. 19.

[29] National Renewable Energy Laboratory ("NREL"), 2023 Annual Technology Baseline Report, *available at* https://data.openei.org/files/5865/2023-ATB-Data_Master_v9.0.xlsx (Tab "Natural Gas FE," cell P112 (showing the capex required for a 2024 advanced natural gas combined cycle advanced)) (hereafter "NREL 2023 ATB Report").

[30] DEF Exhibit TD-4 (Duke Energy Florida's Avoided Generation Assumptions).

technology costs for power generation. The NREL report estimates the capital costs for a CT at $1,102.60 per kW in 2024.[31]

Q. WHAT IS YOUR RECOMMENDATION REGARDING DUKE'S AVOIDED GENERATOR COST ASSUMPTION?

A. I recommend that Duke replace its existing avoided generation unit cost assumption with a greenfield CT or similar technology to more accurately reflect marginal new generation it would construct to serve growing load. This approach is more realistic and would also align Duke with comparable avoided unit assumptions by the other Florida investor-owned utilities. Based on the benchmarking and Duke's own data, a cost of $949.40 per kW should be utilized and should replace the existing brownfield CT cost assumption of $735.20.

Q. WHAT IS THE IMPACT OF INCREASING THE AVOIDED GENERATION COST ASSUMPTION ON THE CONSERVATION GOALS AND DSM PROGRAM ANALYSES?

A. Applying a higher and more representative cost for an avoided generating unit will enhance the expected cost effectiveness of DEF demand response measures under both the RIM and TRC tests. I recommend that the Commission more heavily weight TRC results when assessing mature and established demand response measures for the purposes of setting DEF's DSM goals, assuming that all prevailing demand response incentive payments remain at prevailing levels unless adjusted prospectively in a DEF Base Rate Case.

---

[31] NREL 2023 ATB Report (Tab "Natural Gas FE," cell P109 (showing 2024 advanced natural gas combustion turbine)).

Q. CAN YOU RECALCULATE THE DSM PROGRAM COST/BENEFIT ANALYSIS INCLUDED IN MR. DUFF'S EXHIBIT TD-6?

A. No. I cannot recalculate or adjust variables in the DSM program analysis and modeling as Duke would not provide a working model or workpapers to perform adjustments. I requested the workpaper used to generate the results including the RIM, Total Participant, and TRC tests; however, Duke only provided a Microsoft Excel spreadsheet with hard-coded numbers for the total benefits and costs related to the programs.[32]

Q. DOES THIS COMPLETE YOUR DIRECT TESTIMONY?

A. Yes.

32 *See* Exh. TMG-2 at page 4 of 6 (DEF's Response to PCS Phosphate's Third Request for Production of Documents No. 5).

Tony Georgis

Managing Director – Energy Practice

CONTACT

225 Union Blvd., Ste 450
Lakewood, Colorado 80228
tgeorgis@newgenstrategies.net
www.newgenstrategies.net

EDUCATION

Master of Business Administration, Finance Specialization, Texas A&M University

Bachelor of Science in Mechanical Engineering, Texas A&M University

PROFESSIONAL REGISTRATIONS/ CERTIFICATIONS/COMMITTEES

Registered Professional Engineer (PE) Mechanical, Colorado

Registered Professional Engineer (PE) Mechanical, Louisiana

KEY EXPERTISE

Cost of Service and Rate Design

Expert Witness and Litigation Support

Financial / Economic Analysis

Strategic Planning

Sustainability

Mr. Tony Georgis has spent more than 25 years consulting in the energy and public utility markets and was a founding partner of NewGen. Mr. Georgis is currently the Managing Partner for NewGen's Energy Practice. His consulting career has focused on developing utility organizational and financial strategies with defensible, data-driven support. Tony's experience blends strategic planning, stakeholder engagement, expert witness, sustainability, and analytical expertise to deliver a unique, more integrated perspective of the market and utility financial performance. Like other leaders at NewGen, Tony applies his experience and expertise to generate insights and a roadmap to address the utility market's most complex issues and opportunities. His work includes leading strategic planning studies, expert witness testimony, financial and economic analyses, cost of service and rate studies, and market research.

RELEVANT EXPERIENCE

Sustainability, Energy Strategy, and Strategic Planning

Mr. Georgis leads and manages the development of strategic plans and Roadmaps for utilities, energy agencies, and municipal governments to guide decision-making in increasingly complex business environments. His strategic planning experience includes energy, water, wastewater, solid waste utilities, and local government entities. In support of strategic planning engagements, Mr. Georgis often facilitates internal planning teams and external stakeholder engagement activities to promote broad and/or targeted stakeholder input to the plans. A strategic plan or Roadmap development typically includes overarching strategic elements such as the organization's vision/mission, tactical components like projects and activities supporting and ensuring implementation, and tracking/reporting tools for the organization's measurement of progress to the plan.

Mr. Georgis has also led the development of clean energy and sustainability (or CSR) plans for cities, counties, and utilities to improve the triple bottom line (economic, environmental, and social) and energy performance. Mr. Georgis utilizes an enterprise-wide approach to sustainability to manage regulatory, customer, and financial demands while improving the triple bottom line. He has facilitated the development of city-wide sustainability plans and served as a sustainability subject matter expert. In his role, Mr. Georgis collaborated among internal and external stakeholders, including city/utility staff, key department managers, community representatives, utility customers, and non-profit or non-governmental organizations (NGOs). To support sustainability planning efforts, Mr. Georgis has developed optimization models to prioritize and identify the "next best dollar spent" to pursue sustainability goals while estimating total costs to implement. He has also implemented sustainability auditing/reporting tools such as greenhouse gas (GHG) inventories/reporting and the development of a utility-tailored version of the Global Reporting Initiative (GRI).

Sustainability, Energy Strategy, and Strategic Planning (cont.)

Mr. Georgis' clients for sustainability, energy strategy, and strategic planning include:

- Alameda Municipal Power, CA
- City of Colorado Springs, CO
- City of El Paso, TX
- City of Fort Collins, CO
- City of Longmont, CO
- City of Palo Alto Utilities, CA
- Fort Collins Utilities, CO
- Lakeland Electric, FL
- Loudoun County, VA
- Tampa Bay Water, FL
- State of Vermont Department of Public Service, VT
- Western Area Power Administration, CO

Cost of Service and Rate Design

Mr. Georgis leads numerous utility financial planning, cost of service, and rate design projects. Specific tasks typically include:

- The development of the revenue requirement.
- Functionalization of costs.
- Allocation of costs to customer classes.
- Review of existing customer class criteria.
- Evaluation of line extension and facilities charges.
- Rate design.
- Transitioning of models for the client's future use.

He has also led the development of financial forecasting models to support long-term capital, expense, revenue budgeting, and decision-making. Mr. Georgis routinely facilitates workshops to develop utility rate strategies or rate studies and presents the study and financial recommendations to governing bodies, boards, and city councils. Mr. Georgis' clients for cost of service and rate design include:

- Alameda Municipal Power, CA
- American Samoa Power Authority
- Anaheim Public Utilities, CA
- Arizona Public Service, AZ
- Austin Energy, TX
- Benton Public Utility District, WA
- Burbank Water and Power, CA
- Central Cost Community Energy, CA
- City of Cleveland Electric Utility, OH
- City of Garland, TX
- City of Gonzales, CA
- City of Weatherford, TX
- City Utilities, Springfield, MO
- Clean Power Alliance, CA
- Cleveland Public Power, OH
- Colorado Springs Utilities, CO
- Farmington Electric Utility, NM
- Glendale Water and Power, CA
- Imperial Irrigation District, CA
- Lafayette Utilities System, LA
- La Plata Electric Association, CO
- Lincoln Electric System, NE
- Lubbock Power and Light, TX
- Merced Irrigation District, CA
- New Braunfels Utilities, TX
- Pasadena Water and Power, CA
- San Diego County Water Authority, CA
- San Jose Clean Energy, CA
- U.S. Army; Huntsville, AL
- Vernon Public Utilities, CA
- Victorville Gas Utility, CA

TONY GEORGIS

Managing Director – Energy Practice

Economic, Financial or Market Analyses

Mr. Georgis often provides technical, financial, and advisory support services for various energy and utility-related projects. He is an expert in developing financial pro formas, bond financings, performing scenario analyses, and evaluating market conditions to support project financing or feasibility decision-making. He has analyzed technical assumptions, optimized project financing, performed scenario/sensitivity analyses, and assisted clients in bidding processes. He has provided economic analyses of utility-scale renewable energy projects, power plant fuel conversions, LNG terminals, conventional/renewable distributed energy resources, and DSM/demand response program benefits. Mr. Georgis' clients for economic, financial, or market analyses include:

- Arizona Power Authority, AZ
- Austin Energy, TX
- CalRecycle, CA
- CPS Energy, TX
- Ember Infrastructure, NY
- Fayetteville Public Works Commission, NC
- Florida Municipal Power Agency, FL
- Fort Collins Utilities, CO
- Freeport Container Port, Grand Bahama
- Hawaii Gas Company, HI
- ISO-New England, MA
- Kings River Conservation District, CA
- Niobrara Energy Development, CO
- Solid Waste Authority of Central Ohio, OH
- Terrebonne Parrish, LA
- U.S. Army; Huntsville, AL
- Water and Power Authority, US Virgin Islands

Expert Witness and Litigation Support

Mr. Georgis has provided expert testimony since 2014 regarding electric utility revenue requirements, cost of service, rate design, and ratemaking issues before state and local regulatory bodies and courts. He has national experience providing litigation support regarding ratemaking matters at wholesale and retail levels in California, Florida, Indiana, and Texas.

Mr. Georgis' expert witness and litigation support experience include:

Public Utility Commission of Texas

- Centerpoint Energy Houston Electric, LLC; SOAH Docket No. 473-14-3897 and PUC Docket No. 42560
- City of Lubbock, Lubbock Power & Light; PUC Docket No. 52390
- City of Lubbock, Lubbock Power & Light; SOAH Docket No. 473-24-04313; PUC Docket No. 54657
- City of Lubbock, Lubbock Power & Light; SOAH Docket No. 473-21-0043 and PUC Docket No. 51100
- Oncor Electric Delivery Company; SOAH Docket No. 473-22-2695 and PUC Docket 53601
- Southwestern Electric Power Company (SWEPCO); SOAH Docket No. 473-21-0538 and PUC Docket No. 51415

Indiana Utility Regulatory Commission

- Indiana Michigan Power Company, Cause No. 45993
- Northern Indiana Public Service Company LLC (NIPSCO); Cause No. 45159

Northern Indiana Public Service Company LLC (NIPSCO); Cause No. 45772

TONY GEORGIS

Managing Director – Energy Practice

Florida Public Service Commission

- Duke Energy, Florida; Docket No. 20210016-EI
- Florida Power & Light Company; Docket No. 20210015-EI

Superior Court of the State of California for the County of Los Angeles

- City of Pasadena – Pasadena Water and Power; No. BC 677632

California Public Utility Commission

- Pacific Gas and Electric Company CPUC Application No. 21-06-021
- Southern California Edison Company CPUC Application No. 23-05-010
- San Diego Gas and Electric Company CPUC Application No. 22-05-016

PRESENTATIONS AND PUBLICATIONS

Mr. Georgis has presented at numerous industry associations and conferences, provided training for utility staff, and published several trade journal articles. These efforts have focused on utility finance, strategic planning, market trends/opportunities, and sustainability. Mr. Georgis' presentations and publications are detailed below.

Presentations

APPA Legislative Rally Preconference Seminar, 2020

- *Demystifying Distributed Energy Resources*

APPA Business and Finance Conference Preconference Seminar, 2019

- *Distributed Energy Resources: Risks and Opportunities*

APPA National Conference – Preconference Seminars, 2017/2018/2019

- *Distributed Energy Resources: Risks and Opportunities*

Washington PUD Association Finance Officers, 2016

- *Balancing Aging Infrastructure, Rates, and Residential Demand*

Harvard University Zofnass Program for Sustainable Infrastructure, 2011

- *Tools and Frameworks to Drive the Business Case for Sustainability*

Association of Climate Change Officers, 2010

- *SEC Climate Change Disclosure Guidance*

Platts Energy Markets Webinar, 2010

- *SEC Guidance on Climate Change Disclosures*

Global Commerce Conference, 2010

- *Leadership in Sustainability – Sustainability Decision Making, Implementation and Reporting*

University of Colorado Denver Managing for Sustainability, 2012

- *Regulatory Drivers for Sustainability*

Inter-American Development Bank, 2010

- *Transportation Sustainability and Climate Change Seminar*

Tire Industry Association Scrap to Profit, 2010

- *Evolution of the Carbon Markets and Opportunities for the Scrap Tire Industry*

Energy Utility and Environmental Conference, 2010

- *Evolution and Optimization of Energy Efficiency and Smart Grid Measures*

Tire Industry Association Recycling Conference, 2009

- *Carbon Credits and Recycling Products*

Tire Industry Association Recycling Conference, 2008

- *Selling Tire-derived Products to the Architectural and Construction Markets*

Articles

- *Growing Role for Demand Response in ISO Operations. Utility Automation and Engineering T&D*, November 2008
- *Recycling and Climate Change: A Primer. Resource Recycling*, August 2009
- *Recycling and Climate Change: Opportunities for Recycling as a Climate Change Strategy. Resource Recycling*, September 2009

Record of Testimony: **Tony Georgis, P.E.**

UTILITY	PROCEEDING	SUBJECT	BEFORE	CLIENT	YEAR
1. Indiana Michigan Power Company	Cause No. 45993	Authority to Increase its Rates and Charges for Electric Utility Service Through a Phase in Rate Adjustment	Indiana Utility Regulatory Commission	City of Fort Wayne, the City of Marion, and Marion Municipal Utilities	2023
2. San Diego Gas & Electric Company	CPUC Application No. 22-05-016	Application of San Diego Gas & Electric Company (U 902 M) for Authority, Among Other Things, to Update its Electric and Gas Application 22-05-016 Revenue Requirement and Base Rates Effective on January 1, 2024	California Public Utility Commission	Joint Community Choice Aggregators	2023
3. City of Lubbock, Lubbock Power & Light	PUC Docket No. 54657	Application of the City of Lubbock for Authority to Change Rates for Wholesale Transmission Service	State Office of Administrative Hearings, Public Utility Commission of Texas	Lloyd Gosselink Rochelle & Townsend, P.C.	2023
4. Northern Indiana Public Service Company LLC (NIPSCO)	Cause No. 45772	Petition of Northern Indiana Public Service Company LLC (NIPSCO) Authority to 1) Modify Electric Utility Rates; 2) Approval of New Schedules of Rates and Changes, General Rules and Regulations and Riders; 3) Approval of a new Rider for VOM, and other requests.	Indiana Utility Regulatory Commission	Bose McKinney & Evans LLP, United States Steel Corporation	2023
5. Pacific Gas and Electric Company	CPUC Application No. 21-06-021	Application for 2023 General Rate Case	California Public Utility Commission	Joint Community Choice Aggregators	2022
6. City of Lubbock, Lubbock Power & Light	PUC Docket No. 52390	Application of the City of Lubbock for Authority for Interim Update of Wholesale Transmission Rates	State Office of Administrative Hearings, Public Utility Commission of Texas	Lloyd Gosselink Rochelle & Townsend, P.C.	2021
7. Florida Power & Light Company	Docket No. 20210015-EI	Petition for Rate Increase by Florida Power & Light Company	Florida Public Service Commission	Stone Mattheis Xenopoulos & Brew, PC; Florida Retail Federation	2021

UTILITY	PROCEEDING	SUBJECT	BEFORE	CLIENT	YEAR
8. Southwestern Electric Power Company (SWEPCO)	SOAH Docket No. 473-21-0538 PUC Docket No. 51415	Application of Southwestern Electric Power Company for Authority to Change Rates	State Office of Administrative Hearings, Public Utility Commission of Texas	Office of Public Utility Counsel	2021
9. City of Pasadena – Pasadena Water and Power	BC 677632	Komesar vs. City of Pasadena; State of California Proposition 218, City General Fund Transfer from Utility	Superior Court of the State of California for the County of Los Angeles	Jarvis, Fay and Gibson, LLP; City of Pasadena	2020
10. City of Lubbock, Lubbock Power & Light	SOAH Docket No. 473-21-0043 PUC Docket No. 51100	Application of the City of Lubbock for Authority to Establish Initial Wholesale Transmission Rates and Tariffs	State Office of Administrative Hearings, Public Utility Commission of Texas	Lloyd Gosselink Rochelle & Townsend, P.C.	2020
11. Northern Indiana Public Service Company LLC (NIPSCO)	Cause No. 45159	Petition of Northern Indiana Public Service Company LLC (NIPSCO) Authority to 1) Modify Electric Utility Rates; 2) Approval of New Schedules of Rates and Changes, General Rules and Regulations and Riders; 3) Approval of Revised Common and Electric Depreciation Rates; 4) Accounting Relief; and 5) Approval of New Service Structure for Industrial Rates	Indiana Utility Regulatory Commission	Bose McKinney & Evans LLP, United States Steel Corporation	2019
12. CenterPoint Energy Houston Electric, LLC	SOAH Docket No. 473-14-3897 PUC Docket No. 42560	Application of CenterPoint Energy Houston Electric, LLC for Approval of an Adjustment to its Energy Efficiency Cost Recovery Factor	State Office of Administrative Hearings, Public Utility Commission of Texas	Lloyd Gosselink Rochelle & Townsend, P.C., Gulf Coast Coalition of Cities	2014

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Commission review of numeric Conservation goals by Duke Energy Florida, LLC.	Docket No. 20240013-EG Dated: May 13, 2024

DUKE ENERGY FLORIDA, LLC'S RESPONSES TO
PCS PHOSPHATE'S THIRD SET OF INTERROGATORIES (NOS. 10-11)

Duke Energy Florida, LLC ("DEF") responds to White Springs Agricultural Chemicals, Inc. d/b/a PCS Phosphate – White Springs Third Set of Interrogatories to DEF (Nos. 10-11), as follows:

INTERROGATORIES

10. For the years 2021-2023, for each of the current rates CS-1, CS-2, CS-3, CST-1, CST-2, CST-3, IS-1, IS-2, IST-1 and IST-2, please state the number of customers participating in each of the curtailable or interruptible credit programs.

Response:

Number of Customers Participating

Year	CS-1	CS-2	CS-3	CST-1	CST-2	CST-3	IS-1	IS-2	IST-1	IST-2
2021	0	0	0	3	0	0	37	9	46	98
2022	0	0	0	3	0	0	4	24	1	140
2023	0	0	0	3	0	0	0	25	1	143

11. For each of the plan years 2025-2034, please provide the total (rather than incremental) projected or expected:

a. Number of customers participating in each of the curtailable or interruptible credit programs; and

b. Amount of curtailable and interruptible kW.

Response:

a.

Number of Customers Participating

Year	CS-1	CS-2	CS-3	CST-1	CST-2	CST-3	IS-1	IS-2	IST-1	IST-2
2024	0	0	0	3	0	0	0	25	1	143
2025	0	0	0	3	0	0	0	25	1	144
2026	0	0	0	3	0	0	0	25	1	145
2027	0	0	0	3	0	0	0	25	1	146
2028	0	0	0	3	0	0	0	25	1	147
2029	0	0	0	3	0	0	0	25	1	148
2030	0	0	0	3	0	0	0	25	1	149
2031	0	0	0	3	0	0	0	25	1	150
2032	0	0	0	3	0	0	0	25	1	151
2033	0	0	0	3	0	0	0	25	1	152
2034	0	0	0	3	0	0	0	25	1	153

b.

Amount of Curtailable and Interruptible kW

Year	CS-1	CS-2	CS-3	CST-1	CST-2	CST-3	IS-1	IS-2	IST-1	IST-2
2024	0	0	0	0	10,849	0	0	16,073	0	374,909
2025	0	0	0	0	10,849	0	0	16,073	0	374,909
2026	0	0	0	0	10,849	0	0	16,073	0	374,909
2027	0	0	0	0	10,849	0	0	16,073	0	374,909
2028	0	0	0	0	10,849	0	0	16,073	0	374,909
2029	0	0	0	0	10,849	0	0	16,073	0	374,909
2030	0	0	0	0	10,849	0	0	16,073	0	374,909
2031	0	0	0	0	10,849	0	0	16,073	0	374,909
2032	0	0	0	0	10,849	0	0	16,073	0	374,909
2033	0	0	0	0	10,849	0	0	16,073	0	374,909
2034	0	0	0	0	10,849	0	0	16,073	0	374,909

AFFIDAVIT

STATE OF NORTH CAROLINA

COUNTY OF MECKLENBURG

I hereby certify that on this 2nd day of May, 2024, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared TIM DUFF who is personally known to me or has produced NC Drivers License as identification, and he acknowledged before me that he provided the answers to interrogatory numbers 10-11 from PCS Phosphate's Third Set of Interrogatories to Duke Energy Florida, LLC (Nos. 10-11) in Docket No. 20240013-EG, and that the responses are true and correct based on his personal knowledge.

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 2nd day of May, 2024.

Tim Duff

Notary Public
State of North Carolina

My Commission Expires:
01/21/29

TERESA RAY
My Commission Expires
NOTARY
PUBLIC
01-21-29
UNION COUNTY, NC

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Commission review of numeric Conservation goals by Duke Energy Florida, LLC.

Docket No. 20240013-EG

Dated: May 13, 2024

DUKE ENERGY FLORIDA, LLC'S RESPONSE TO PCS PHOSPHATE'S THIRD REQUEST FOR PRODUCTION OF DOCUMENTS (NO. 5)

Duke Energy Florida, LLC ("DEF") responds to White Springs Agricultural Chemicals, Inc. d/b/a PCS Phosphate – White Springs' ("PCS Phosphate") Third Request for Production of Documents (No. 5), as follows:

DOCUMENTS REQUESTED

5. Please refer to Exhibit TD-6. Please provide all workpapers supporting the calculation of the benefits and costs for each test (Rate Impact Measure, Total Resource Cost, and Participant Cost) in native format.

Response:
Please see excel file "DEF's Response to PCS Phosphate POD 03 (5)_lmj" bearing Bates number 20240013-PCSPOD3-00001153.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Commission review of numeric Conservation goals by Duke Energy Florida, LLC.

Docket No. 20240013-EG

Dated: May 28, 2024

DUKE ENERGY FLORIDA, LLC'S RESPONSES TO
PCS PHOSPHATE'S FIFTH SET OF INTERROGATORIES (NO. 17)

Duke Energy Florida, LLC ("DEF") responds to White Springs Agricultural Chemicals, Inc. d/b/a PCS Phosphate – White Springs Fifth Set of Interrogatories to DEF (No. 17), as follows:

INTERROGATORIES

17. Please refer to DEF's response to PCS Phosphate's First Request for Production of Documents, Question 1. For all years shown, please confirm that estimated program costs shown for Interruptible Service, Curtailable Service, and Stand-by Generation Service reflect credit levels currently in effect.

Response:
The Company confirms that estimated program costs shown for Interruptible Service, Curtailable Service, and Stand-by Generation Service reflect credit levels currently in effect.

AFFIDAVIT

STATE OF NORTH CAROLINA

COUNTY OF MECKLENBURG

I hereby certify that on this 13th day of May, 2024, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared TIM DUFF who is personally known to me or has produced NC Drivers License as identification, and he acknowledged before me that he provided the answers to interrogatory number 17 from PCS Phosphate's Fifth Set of Interrogatories to Duke Energy Florida, LLC (No. 17) in Docket No. 20240013-EG, and that the responses are true and correct based on his personal knowledge.

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 13th day of May, 2024.

Tim Duff

Tim Duff

Teresa Ray

Notary Public
State of North Carolina

TERESA RAY
My Commission Expires
NOTARY
PUBLIC
01-21-29
UNION COUNTY, NC

My Commission Expires:

01/21/29

RATE SCHEDULE CS-2
CURTAILABLE GENERAL SERVICE

Availability:

Available throughout the entire territory served by the Company.

Applicable:

To any customer, other than residential, for light and power purposes where the billing demand is 500 kW or more, and where the customer agrees to curtail 25% or more of their average monthly billing demand (based on the most recent twelve (12) months or, where not available, a projection for twelve (12) months).

Character of Service:

Alternating current, 60 cycle, single-phase or three-phase, at the Company's standard voltage available.

Limitation of Service:

Standby or resale service is not permitted hereunder. Curtailable service under this rate schedule is not subject to curtailment during any time period for economic reasons. Curtailable service under this rate schedule is subject to curtailment during any time period that electric power and energy delivered hereunder from the Company's available generating resources is required to a) maintain service to the Company's firm power customers and firm power sales commitments or b) supply emergency interchange service to another utility for its firm load obligations only.

Service under this rate is subject to the Company's currently effective and filed "General Rules and Regulations for Electric Service."

Rate Per Month:

Customer Charge:

Secondary Metering Voltage:	$ 90.57
Primary Metering Voltage:	$ 251.45
Transmission Metering Voltage:	$ 938.45

Demand Charge:	$ 11.21 per kW of Billing Demand
Plus the Cost Recovery Factors on a $/ kW basis in Rate Schedule BA-1, *Billing Adjustments*:	See Sheet No. 6.105 and 6.106
Curtailable Demand Credit:	$ 7.72 per kW of Contracted On-Peak Demand Capability

Plus an additional event incentive of 25¢ times the difference in kWh usage during the 30 minutes preceding the curtailment event and the average 30 minute actual kWh usage during the curtailment event.

Energy Charge:

Non-Fuel Energy Charge:	2.044¢ per kWh
Plus the Cost Recovery Factors on a ¢/ kWh basis in Rate Schedule BA-1, *Billing Adjustments,* except for the Fuel Cost Recovery Factor and Asset Securitization Charge Factor:	See Sheet No. 6.105 and 6.106

Premium Distribution Service Charge:

Where Premium Distribution Service has been established after 12/15/98 in accordance with Subpart 2.05, General Rules and Regulations Governing Electric Service, the customer shall pay a monthly charge determined under Special Provision No. 8 of this rate schedule for the costs of all additional equipment, or the customer's allocated share thereof, installed to accomplish automatic delivery transfer including all line costs necessary to connect to an alternate distribution circuit.

In addition, the Demand Charge included in the Rate per Month section of this rate schedule shall be increased by $1.50 per kW for the cost of reserving capacity in the alternate distribution circuit.

(Continued on Page No. 2)

RATE SCHEDULE CS-2
CURTAILABLE GENERAL SERVICE
(Continued from Page No. 1)

Rating Periods:

(a) On-Peak Periods - The designated On-Peak Periods expressed in terms of prevailing clock time shall be as follows:

(1) For the calendar months of December through February,
Monday through Friday*: 5:00 a.m. to 10:00 a.m.

(2) For all calendar months,
Monday through Friday*: 6:00 p.m. to 9:00 p.m.

* The following general holidays shall be excluded from the On-Peak Periods: New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day and Christmas. In the event the holiday occurs on a Saturday or Sunday, the adjacent weekday shall be excluded from the On-Peak Periods.

Determination of Billing Demand:

The billing demand shall be the maximum 30-minute kW demand established during the current billing period, but not less than 500 kW.

Determination of Contracted On-Peak Demand Capability:

The Contracted On-Peak Demand Capability shall be the lesser of the Contracted Curtailable Demand and the maximum 30-minute kW demand established during designated On-Peak Periods during the current billing period.

Delivery Voltage Credit:

When a customer takes service under this rate at a delivery voltage above standard distribution secondary voltage, the Demand Charge hereunder shall be subject to the following credit:

For Distribution Primary Delivery Voltage:	$1.31 per kW of Billing Demand
For Transmission Delivery Voltage below 230 kV:	$5.42 per kW of Billing Demand
For Transmission Delivery Voltage at or above 230 kV:	$7.50 per kW of Billing Demand

Metering Voltage Adjustment:

Metering voltage will be at the option of the Company. When the Company meters at a voltage above distribution secondary, the appropriate following reduction factor shall apply to the Non-Fuel Energy Charge, Demand Charge, Curtailable Demand Credit and Delivery Voltage Credit hereunder:

Metering Voltage	Reduction Factor
Distribution Primary	1.0%
Transmission	2.0%

Power Factor:

If a customer's power factor at the time of maximum demand in the current billing period is less than 85%, the Company may adjust the Base Demand by multiplying by 85% and dividing the resulting power factor actually established at the time of maximum demand during the current month.

Additional Charges:

Fuel Cost Recovery Factor:	See Sheet No. 6.105
Asset Securitization Charge Factor:	See Sheet No. 6.105
Gross Receipts Tax Factor & Regulatory Assessment Fee Factor:	See Sheet No. 6.106
Right-of-Way Utilization:	See Sheet No. 6.106
Municipal Tax:	See Sheet No. 6.106
Sales Tax:	See Sheet No. 6.106

Minimum Monthly Bill:

The minimum monthly bill shall be the Customer Charge and the Demand Charge for the current billing period. Where special equipment to serve the customer is required, the Company may require a specified minimum charge.

Terms of Payment:

Bills rendered hereunder are payable within the time limit specified on bill at Company-designated locations.

Term of Service:

Service under this rate shall be for a minimum initial term of two (2) years from the commencement of service, and shall continue thereafter until terminated by either party by written notice sixty (60) days prior to termination.

(Continued on Page No. 3)

RATE SCHEDULE CS-2
CURTAILABLE GENERAL SERVICE
(Continued from Page No. 2)

Special Provisions:

1. As used in this rate schedule, the term "period of requested curtailment" shall mean a period for which the Company has requested curtailment and for which energy purchased from sources outside the Company's system, pursuant to Special Provision No. 6, is not available. If such energy can be purchased, the terms of Special Provision No. 6 will apply and a period of requested curtailment will not be deemed to exist while such energy remains available.

2. Under the provisions of this rate, the Company will require a contract with the customer upon the Company's filed standard contract Form No. 2. An initial Non-Curtailable Demand shall be specified in the contract and shall be based on specifications for power requirements supplied to the Company. (Note: the initial contract Non-Curtailable Demand cannot be set any greater than 75% of the customer's average monthly billing demand in accordance with the Applicable Clause of this rate schedule). Contracted Curtailable Demand shall be the difference between the customer's average monthly billing demand and the Non-Curtailable Demand. The contract Non-Curtailable Demand shall be re-established under the following conditions:

   (a) If a change in the customer's power requirements occurs, the Company and the customer shall establish a new contract Non-Curtailable Demand.

   (b) If the customer establishes a demand higher than the contract Non-Curtailable demand during any period of requested curtailment in the billing period, such higher demand shall become the contract Non-Curtailable Demand effective with the next billing period. In addition. Special Provision No. 5 is applicable.

   (c) If the customer establishes a demand lower than the contract Non-Curtailable demand during all periods of requested curtailment in the billing period, such lower demand upon request by the customer shall become the contract Non-Curtailable Demand effective with the next billing period.

   (d) If the customer's contract Non-Curtailable Demand exceeds 75% of the customer's average monthly billing demand (based on the most recent twelve (12) months or, where not available, a projection of twelve (12) months), the contract Non-Curtailable Demand shall be set equal to 75% of the customer's average monthly billing demand effective with the current billing period. A re-establishment of the customer's contract Non-Curtailable Demand under this condition shall supersede any other establishment.

3. As an essential requirement for receiving the Curtailable Demand Credit provided under this rate schedule, a customer shall be strictly responsible for the curtailment of his power requirements to no more than his contract Non-Curtailable Demand upon each request of the Company. Such requests will normally be made during periods of capacity shortages on the Company's system; however, other operating contingencies may result in such requests at other times. The Company shall also have the right to request at least one additional curtailment each calendar year irrespective of capacity availability or operating conditions.

4. A customer will be deemed to have complied with his curtailment responsibility if the maximum 30-minute kW demand established during each period of requested curtailment does not exceed his contract Non-Curtailable Demand.

5. If the maximum 30-minute kW demand established during a requested curtailment in the billing period exceeds the customer's contract Non-Curtailable Demand, the customer will be billed the following additional charge for all billing periods from the most recent prior billing period of requested curtailment through the current billing period, not to exceed a total of twelve (12) billing periods:

   1.25 times the difference in Demand and Energy Charges which would result under Rate Schedule GSD-1 and those Demand and Energy Charges calculated under this rate schedule plus the difference between ECCR, CCR and ECRC of this rate schedule and GSD-1. This calculation shall be exclusive of any additional charges rendered under Special Provision No. 6 of this rate schedule.

(Continued on Page No. 4)

RATE SCHEDULE CS-2
CURTAILABLE GENERAL SERVICE
(Continued from Page No. 3)

Special Provisions: (Continued)

6. To minimize the frequency and duration of curtailments requested under this rate schedule, the Company will attempt to purchase additional energy, if available, from sources outside the Company's system during periods for which curtailment would otherwise be requested. The Company will also attempt to notify any customer, desirous of such notice, in advance when such purchases are imminent or as soon as practical thereafter where advance notice is not feasible. Similar notification will be provided upon termination of such purchases.

7. If the customer increases his power requirements in any manner which requires the Company to install additional facilities for the specific use of the customer, a new Term of Service may be required at the Company's option.

8. The Company will furnish service under this rate at a single voltage. Any equipment to supply additional voltages or any additional facilities for the use of the customer shall be furnished and maintained by the customer. At its option, the Company may furnish, install and maintain such additional equipment upon request of the customer, in which event an additional monthly charge will be made at the rate of 1.08% times the installed cost of such additional equipment.

9. Customers taking service under this curtailable rate schedule who desire to transfer to a firm rate schedule will be required to give the Company written notice at least thirty-six (36) months prior to such transfer. Such notice shall be irrevocable unless the Company and the customer shall mutually agree to void the revocation.

10. Service under this rate is not available if all or a part of the customer’s load is designated by the appropriate governmental agency for use as a public shelter during periods of emergency or natural disaster.

11. Any customer who established a billing demand of less than 500 kW in any of the 12 billing periods preceding May 1, 2002, shall be advised by the Company that the minimum billing demand of 500 kW would not apply in the event the customer exercises Special Provision No. 9 of this rate.

RATE SCHEDULE CST-2
CURTAILABLE GENERAL SERVICE
OPTIONAL TIME OF USE RATE

Availability:

Available throughout the entire territory served by the Company.

Applicable:

At the option of customers otherwise eligible for service under Rate Schedule CS-2, provided that all of the electric load requirements on the customer's premises are metered through one point of delivery.

Character of Service:

Alternating current, 60 cycle, single-phase or three-phase, at the Company's standard voltage available.

Limitation of Service:

Standby or resale service is not permitted hereunder. Curtailable service under this rate schedule is not subject to curtailment during any time period for economic reasons. Curtailable service under this rate schedule is subject to curtailment during any time period that electric power and energy delivered hereunder from the Company's available generating resources is required to a) maintain service to the Company's firm power customers and firm power sales commitments or b) supply emergency interchange service to another utility for its firm load obligations only.

Service under this rate is subject to the Company's currently effective and filed "General Rules and Regulations for Electric Service."

Rate Per Month:

Customer Charge:

Secondary Metering Voltage:	$ 90.57
Primary Metering Voltage:	$ 251.45
Transmission Metering Voltage:	$ 938.45

Demand Charges:

Base Demand Charge:	$ 1.63 per kW of Base Demand
Mid-Peak Demand Charge:	$ 4.79 per kW of Mid-Peak Demand
On-Peak Demand Charge:	$ 1.33 per kW of On-Peak Demand
Plus the Cost Recovery Factors on a $/kW basis in Rate Schedule BA-1, *Billing Adjustments*, using Monthly Max Demand:	See Sheet No. 6.105 and 6.106

Curtailable Demand Credit: $ 7.72 per kW of Contracted On-Peak Demand Capability

Plus an additional event incentive of 25¢ times the difference in kWh usage during the 30 minutes preceding the curtailment event and the average 30-minute actual kWh usage during the curtailment event.

Energy Charge:

Non-Fuel Energy Charge:	1.880¢ per On-Peak kWh 1.628¢ per Off-Peak kWh 1.029¢ per Super-Off-Peak kWh
Plus the Cost Recovery Factors on a ¢/ kWh basis in Rate Schedule BA-1, *Billing Adjustments,* except for the Fuel Cost Recovery Factor and Asset Securitization Charge Factor:	See Sheet No. 6.105 and 6.106

The On-Peak rate shall apply to energy use during On-Peak Periods. The Super-Off-Peak rate shall apply to energy used during the designated Super-Off-Peak Periods. The Off-Peak rate shall apply to all other energy use.

Premium Distribution Service Charge:

Where Premium Distribution Service has been established after 12/15/98 in accordance with Subpart 2.05, General Rules and Regulations Governing Electric Service, the customer shall pay a monthly charge determined under Special Provision No. 8 of this rate schedule for the costs of all additional equipment, or the customer's allocated share thereof, installed to accomplish automatic delivery transfer including all line costs necessary to connect to an alternate distribution circuit.

In addition, the Base Demand Charge included in the Rate per Month section of this rate schedule shall be increased by $1.50 per kW for the cost of reserving capacity in the alternate distribution circuit.

(Continued on Page No. 2)

RATE SCHEDULE CST-2
CURTAILABLE GENERAL SERVICE
OPTIONAL TIME OF USE RATE
(Continued from Page No. 1)

Rating Periods:

(a) On-Peak Periods - The designated On-Peak Periods expressed in terms of prevailing clock time shall be as follows:

(1) For the calendar months of December through February,
Monday through Friday *: 5:00 a.m. to 10:00 a.m.

(2) For all calendar months,
Monday through Friday*: 6:00 p.m. to 9:00 p.m.

* The following general holidays shall be excluded from the On-Peak Periods: New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day and Christmas. In the event the holiday occurs on a Saturday or Sunday, the adjacent weekday shall be excluded from the On-Peak Periods.

(b) Super-Off-Peak Periods - The designated Super-Off-Peak Periods expressed in terms of prevailing clock time shall be as follows:
For the calendar months of March through November,

Every day, including weekends and holidays 12:00 a.m. (midnight) to 6:00 a.m.

(c) Off-Peak Periods - The designated Off-Peak Periods shall be all periods other than the designated On-Peak and Super-Off-Peak Periods set forth in (a) and (b) above.

Determination of Billing Demands:

The billing demands shall be the following:

(a) The Base Demand shall be the maximum 30-minute kW demand established over the current and eleven previous billing periods, but not less than 500 kW.

(b) The Mid-Peak Demand shall be the maximum 30-minute kW demand established during the designated On-Peak or Off-Peak Periods during the current billing period.

(c) The On-Peak Demand shall be the maximum 30-minute kW demand established during designated On-Peak Periods during the current billing period.

(d) The Monthly Max Demand shall be the maximum 30-minute kW demand established during the current billing period.

Determination of Contracted On-Peak Demand Capability:

The Contracted On-Peak Demand Capability shall be the lesser of the Contracted Curtailable Demand and the maximum 30-minute kW demand established during designated On-Peak Periods during the current billing period.

Delivery Voltage Credit:

When a customer takes service under this rate at a delivery voltage above standard distribution secondary voltage, the Base Demand Charge hereunder shall be subject to the following credit:

For Distribution Primary Delivery Voltage:	$1.31 per kW of Monthly Max Demand
For Transmission Delivery Voltage below 230 kV:	$5.42 per kW of Monthly Max Demand
For Transmission Delivery Voltage at or above 230 kV:	$7.50 per kW of Monthly Max Demand

Note: In no event shall the total of the Demand Charges hereunder, after application of the above credit, be an amount less than zero.

Metering Voltage Adjustment:

Metering voltage will be at the option of the Company. When the Company meters at a voltage above distribution secondary, the appropriate following reduction factor shall apply to the Non-Fuel Energy Charge, Demand Charges, Curtailable Demand Credit and Delivery Voltage Credit hereunder:

Metering Voltage	Reduction Factor
Distribution Primary	1.0%
Transmission	2.0%

Power Factor:

If a customer's power factor at the time of maximum demand in the current billing period is less than 85%, the Company may adjust the Base Demand by multiplying by 85% and dividing by the resulting power factor actually established at the time of maximum demand during the current month.

(Continued on Page No. 3)

RATE SCHEDULE CST-2
CURTAILABLE GENERAL SERVICE
OPTIONAL TIME OF USE RATE
(Continued from Page No. 2)

Additional Charges:

Fuel Cost Recovery Factor:	See Sheet No. 6.105
Asset Securitization Charge Factor:	See Sheet No. 6.105
Gross Receipts Tax & Regulatory Assessment Fee Factor:	See Sheet No. 6.106
Right-of-Way Utilization:	See Sheet No. 6.106
Municipal Tax:	See Sheet No. 6.106
Sales Tax:	See Sheet No. 6.106

Minimum Monthly Bill:

The minimum monthly bill shall be the Customer Charge. Where special equipment to serve the customer is required, the Company may require a specified minimum charge.

Terms of Payment:

Bills rendered hereunder are payable within the time limit specified on the bill at Company-designated locations.

Term of Service:

For customers electing to take service hereunder in lieu of the otherwise applicable Rate Schedule CS-2, the term of service requirements under this optional rate schedule shall be the same as that required under Rate Schedule CS-2 provided, however, at a given location the customer shall have the right during the initial term of service to transfer to the otherwise applicable Rate Schedule CS-2 at any time. It is further provided, however, that any such customer who subsequently re-elects to take service hereunder at the same location shall be required to remain on the optional rate at that location for a minimum term of twelve (12) months.

Special Provisions:

1. As used in this rate schedule, the term "period of requested curtailment" shall mean a period for which the Company has requested curtailment and for which energy purchased from sources outside the Company's system, pursuant to Special Provision No. 6, is not available. If such energy can be purchased, the terms of Special Provision No. 6 will apply and a period of requested curtailment will not be deemed to exist while such energy remains available.

2. Under the provisions of this rate, the Company will require a contract with the customer upon the Company's filed standard contract Form No. 2. An initial Non-Curtailable Demand shall be specified in the contract and shall be based on specifications for power requirements supplied to the Company. (Note: the initial contract Non-Curtailable Demand cannot be set any greater than 75% of the customer's average monthly billing demand in accordance with the Applicable Clause of Rate Schedule CS-2). Contracted Curtailable Demand shall be the difference between the customer's average monthly billing demand and the Non-Curtailable Demand. The contract Non-Curtailable Demand shall be re-established under the following conditions:

   (a) If a change in the customer's power requirements occurs, the Company and the customer shall establish a new contract Non-Curtailable Demand.

   (b) If the customer establishes a demand higher than the contract Non-Curtailable demand during any period of requested curtailment in the billing period, such higher demand shall become the contract Non-Curtailable Demand effective with the next billing period. In addition, Special Provision No. 5 is applicable.

   (c) If the customer establishes a demand lower than the contract Non-Curtailable Demand during all periods of requested curtailment in the billing period, such lower demand upon request by the customer shall become the contract Non-Curtailable Demand effective with the next billing period.

(Continued on Page No. 4)

RATE SCHEDULE CST-2
CURTAILABLE GENERAL SERVICE
OPTIONAL TIME OF USE RATE
(Continued from Page No. 3)

Special Provisions: (Continued)

(d) If the customer's contract Non-Curtailable Demand exceeds 75% of the customer's average monthly billing demand (based on the most recent twelve (12) months or, where not available, a projection of twelve (12) months), the contract Non-Curtailable Demand shall be set equal to 75% of the customer's average monthly billing demand effective with the current billing period. A re-establishment of the customer's contract Non-Curtailable Demand under this condition shall supersede any other establishment.

3. As an essential requirement for receiving the Curtailable Demand Credit provided under this rate schedule, a customer shall be strictly responsible for the curtailment of his power requirements to no more than his contract Non-Curtailable Demand upon each request of the Company. Such requests will normally be made during periods of capacity shortages on the Company's system; however, other operating contingencies may result in such requests at other times. The Company shall also have the right to request at least one additional curtailment each calendar year irrespective of capacity availability or operating conditions.

4. A customer will be deemed to have complied with his curtailment responsibility if the maximum 30-minute kW demand established during each period of requested curtailment does not exceed his contract Non-Curtailment Demand.

5. If the maximum 30-minute kW demand established during a requested curtailment in the billing period exceeds the customer's contract Non-Curtailable Demand, the customer will be billed the following additional charge for all billing periods from the most recent prior billing period of requested curtailment through the current billing period, not to exceed a total of twelve (12) billing periods:

   1.25 times the difference in Demand and Energy Charges which would result under Rate Schedule GSDT-1 and those Demand and Energy Charges calculated under this rate schedule plus the difference between ECCR, CCR and ECRC of this rate schedule and GSDT-1. This calculation shall be exclusive of any additional charges rendered under Special Provision No. 6 of this rate schedule.

6. To minimize the frequency and duration of curtailments requested under this rate schedule, the Company will attempt to purchase additional energy, if available, from sources outside the Company's system during periods for which curtailment would otherwise be requested. The Company will also attempt to notify any customer, desirous of such notice, in advance when such purchases are imminent or as soon as practical thereafter where advance notice is not feasible. Similar notification will be provided upon termination of such purchases.

7. If the customer increases their power requirements in any manner which requires the Company to install additional facilities for the specific use of the customer, a new Term of Service may be required at the Company's option.

8. The Company will furnish service under this rate at a single voltage. Any equipment to supply additional voltages or any additional facilities for the use of the customer shall be furnished and maintained by the customer. At its option, the Company may furnish, install, and maintain such additional equipment upon request of the customer, in which event an additional monthly charge will be made at the rate of 1.08% times the installed cost of such additional equipment.

9. Customers taking service under this curtailable rate schedule who desire to transfer to a firm rate schedule will be required to give the Company written notice at least thirty-six (36) months prior to such transfer. Such notice shall be irrevocable unless the Company and the customer shall mutually agree to void the revocation.

10. Service under this rate is not available if all or a part of the customer's load is designated by the appropriate governmental agency for use at a public shelter during periods of emergency or natural disaster.

11. Any customer who established a Base billing demand of less than 500 kW in any of the 12 billing periods proceeding May 1, 2002, shall be advised by the Company that the minimum billing demand of 500 kW would not apply in the event the customer exercises Special Provision No. 9 of this rate.

RATE SCHEDULE IS-2
INTERRUPTIBLE GENERAL SERVICE

Availability:

Available throughout the entire territory served by the Company.

Applicability:

Applicable to customers, other than residential, for light and power purposes where the billing demand is 500 kW or more, and where service may be interrupted by the Company. For customer accounts established under this rate schedule after June 3, 2003, service is limited to premises at which an interruption of electric service will primarily affect only the customer, its employees, agents, lessees, tenants or business guests, and will not significantly affect members of the general public, nor interfere with functions performed for the protection of public health or safety. Examples of premises at which service under this rate schedule may not be provided, unless adequate on-site backup generation is available, include, but are not limited to: retail businesses, offices, and governmental facilities open to members of the general public, stores, hotels, motels, convention centers, theme parks, schools, hospitals and health care facilities, designated public shelters, detention and correctional facilities, police and fire stations, and other similar facilities.

Character of Service:

Alternating current, 60 cycle, single-phase or three-phase, at the Company's standard voltage available.

Limitation of Service:

Standby or resale service not permitted hereunder. Interruptible service under this rate schedule is not subject to interruption during any time period for economic reasons. Interruptible service under this rate schedule is subject to interruption during any time period that electric power and energy delivered hereunder from the Company's available generating resources is required to a) maintain service to the Company's firm power customers and firm power sales commitments or b) supply emergency Interchange service to another utility for its firm load obligations only.

Service under this rate is subject to the Company's currently effective and filed "General Rules and Regulations for Electric Service."

Rate Per Month:

Customer Charge:

Secondary Metering Voltage:	$ 332.54
Primary Metering Voltage:	$ 493.43
Transmission Metering Voltage:	$ 1,180.47

Demand Charge:	$ 9.31 per kW of Billing Demand
Plus the Cost Recovery Factors on a $/ kW basis in Rate Schedule BA-1, *Billing Adjustments*:	See Sheet No. 6.105 and 6.106
Interruptible Demand Credit:	$ 7.72 per kW of On-Peak Demand

Energy Charge:

Non-Fuel Energy Charge:	1.354¢ per kWh
Plus the Cost Recovery Factors on a ¢/ kWh basis in Rate Schedule BA-1, *Billing Adjustments,* except for the Fuel Cost Recovery Factor and Asset Securitization Charge Factor:	See Sheet No. 6.105 and 6.106

Premium Distribution Service Charge:

Where Premium Distribution Service has been established after 12/15/98 in accordance with Subpart 2.05, General Rules and Regulations Governing Electric Service, the customer shall pay a monthly charge determined under Special Provision No. 5 of this rate schedule for the costs of all additional equipment, or the customer's allocated share thereof, installed to accomplish automatic delivery transfer including all line costs necessary to connect to an alternate distribution circuit.

In addition, the Demand Charge included in the Rate per Month section of this rate schedule shall be increased by $1.50 per kW for the cost of reserving capacity in the alternate distribution circuit.

Rating Periods:

(a) On-Peak Periods - The designated On-Peak Periods expressed in terms of prevailing clock time shall be as follows:

(1) For the calendar months of December through February, Monday through Friday*:	5:00 a.m. to 10:00 a.m.
(2) For all calendar months, Monday through Friday*:	6:00 p.m. to 9:00 p.m.

* The following general holidays shall be excluded from the On-Peak Periods: New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day and Christmas. In the event the holiday occurs on a Saturday or Sunday, the adjacent weekday shall be excluded from the On-Peak Periods.

(Continued on Page No. 2)

RATE SCHEDULE IS-2
INTERRUPTIBLE GENERAL SERVICE
(Continued from Page No. 1)

Determination of Billing Demands:

The billing demands shall be the following:

(a) The Base Demand shall be the maximum 30-minute kW demand established during the current billing period, but not less than 500 kW.

(b) The On-Peak Demand shall be the maximum 30-minute kW demand established during designated On-Peak Periods during the current billing period.

Delivery Voltage Credit:

When a customer takes service under this rate at a delivery voltage above standard distribution secondary voltage, the Demand charge hereunder shall be subject to the following credit:

For Distribution Primary Delivery Voltage:	$1.31 per kW of Base Demand
For Transmission Delivery Voltage below 230 kV:	$5.42 per kW of Base Demand
For Transmission Delivery Voltage at or above 230 kV:	$7.50 per kW of Base Demand

Metering Voltage Adjustment:

Metering voltage will be at the option of the Company. When the Company meters at a voltage above distribution secondary, the appropriate following reduction factor shall apply to the Non-Fuel Energy Charge, Demand Charge, Interruptible Demand Credit, and Delivery Voltage Credit hereunder:

Metering Voltage	Reduction Factor
Distribution Primary	1.0%
Transmission	2.0%

Power Factor:

If a customer's power factor at the time of maximum demand in the current billing period is less than 85%, the Company may adjust the Base Demand by multiplying by 85% and dividing by the resulting power factor actually established at the time of maximum demand during the current month.

Additional Charges:

Fuel Cost Recovery Factor:	See Sheet No. 6.105
Asset Securitization Charge Factor:	See Sheet No. 6.105
Gross Receipts Tax Factor & Regulatory Assessment Fee Factor:	See Sheet No. 6.106
Right-of-Way Utilization Fee:	See Sheet No. 6.106
Municipal Tax:	See Sheet No. 6.106
Sales Tax:	See Sheet No. 6.106

Minimum Monthly Bill:

The minimum monthly bill shall be the Customer Charge and the Demand Charge for the current billing period. Where special equipment to serve the customer is required, the Company may require a specified minimum charge.

Terms of Payment:

Bills rendered hereunder are payable within the time limit specified on bill at Company-designated locations.

Term of Service:

Service under this rate schedule shall be for a minimum initial term of five (5) years from the commencement of service, and shall continue thereafter until terminated by either party by written notice sixty (60) days prior to termination.

Special Provisions:

1. When the customer increases the electrical load, which increase requires the Company to increase facilities installed for the specific use of the customer, a new Term of Service may be required under this rate at the option of the Company.

2. Customers taking service under another Company rate schedule who elect to transfer to this rate will be accepted by the Company on a first-come, first-served basis. Required equipment (metering, under-frequency relay, etc.) will be installed accordingly, subject to availability. Service under this rate schedule shall commence with the first full billing period following the date of equipment installation. Before commencement of service under this rate, the Company shall exercise an interruption for purposes of testing its equipment. The Company shall also have the right to exercise at least one additional interruption each calendar year irrespective of capacity availability or operating conditions. The Company will give the customer notice of the test.

(Continued on Page No. 3)

RATE SCHEDULE IS-2
INTERRUPTIBLE GENERAL SERVICE
(Continued from Page No. 2)

Special Provisions: (Continued)

3. The Company may, under the provisions of this rate, at its option, require a special contract with the customer upon the Company's filed contract form.

4. The Company will attempt to minimize interruption hereunder by purchasing power and energy from other sources during periods of normal interruption. The Company will also attempt to notify any customer, desirous of such notice, in advance when such purchases are imminent or as soon as practical thereafter where advance notice is not feasible. Similar notification will be provided upon termination of such purchases.

5. The Company will furnish service under this rate at a single voltage. Equipment to supply additional voltages or additional facilities for the use of the customer shall be furnished and maintained by the customer. The customer may request the Company to furnish such additional equipment, and the Company, at its sole option, may furnish, install, and maintain such additional equipment, charging the customer for the use thereof at the rate of 1.08% per month of the installed cost of such additional equipment.

6. Customers taking service under this interruptible rate schedule who desire to transfer to a non-interruptible rate schedule will be required to give the Company written notice at least thirty-six (36) months prior to such transfer. Such notice shall be irrevocable unless the Company and the customer shall mutually agree to void the revocation.

7. Service under this rate is not available if all of a part of the customer's load is designated by the appropriate governmental agency for use as a public shelter during periods of emergency or natural disaster

8. Any customer who established a billing demand of less than 500 kW in any of the 12 billing periods proceeding May 1, 2002, shall be advised by the Company that the minimum billing demand of 500 kW would not apply in the event the customer exercises Special Provision No. 6 of this rate.

RATE SCHEDULE IST-2
INTERRUPTIBLE GENERAL SERVICE
OPTIONAL TIME OF USE RATE

Availability:

Available throughout the entire territory served by the Company.

Applicability:

At the option of the customer, applicable to customers otherwise eligible for service under Rate Schedule IS-2, where the billing demand is 500 kW or more, provided that the total electric requirements at each point of delivery are measured through one meter. For customer accounts established under this rate schedule after June 3, 2003, service is limited to premises at which an interruption of electric service will primarily affect only the customer, its employees, agents, lessees, tenants, or business guests, and will not significantly affect members of the general public, nor interfere with functions performed for the protection of public health or safety. Examples of premises at which service under this rate schedule may not be provided, unless adequate on-site backup generation is available, include, but are not limited to: retail businesses, offices, and governmental facilities open to members of the general public, stores, hotels, motels, convention centers, theme parks, schools, hospitals and health care facilities, designated public shelters, detention and correctional facilities, police and fire stations, and other similar facilities.

Character of Service:

Alternating current, 60 cycle, single-phase or three-phase, at the Company's standard voltage available.

Limitation of Service:

Standby or resale service not permitted hereunder. Interruptible service under this rate schedule is not subject to interruption during any time period for economic reasons. Interruptible service under this rate schedule is subject to interruption during any time period that electric power and energy delivered hereunder from the Company's available generating resources is required to a) maintain service to the Company's firm power customers and firm power sales commitments, or b) supply emergency interchange service to another utility for its firm load obligations only.

Service under this rate is subject to the Company's currently effective and filed "General Rules and Regulations for Electric Service."

Rate Per Month:

Customer Charge:

Secondary Metering Voltage:	$ 332.54
Primary Metering Voltage:	$ 493.43
Transmission Metering Voltage:	$ 1,180.47

Demand Charge:

Base Demand Charge:	$ 1.63 per kW of Base Demand
Mid-Peak Demand Charge:	$ 4.79 per kW of Mid-Peak Demand
On-Peak Demand Charge:	$ 1.33 per kW of On-Peak Demand
Plus the Cost Recovery Factors on a $/kW basis in Rate Schedule BA-1, *Billing Adjustments*, using Monthly Max Demand:	See Sheet No. 6.105 and 6.106

Interruptible Demand Credit: $ 7.72 per kW of On-Peak Demand

Energy Charge:

Non-Fuel Energy Charge:	1.880¢ per On-Peak kWh
	1.628¢ per Off-Peak kWh
	1.029¢ per Super-Off-Peak kWh
Plus the Cost Recovery Factors on a ¢/ kWh basis in Rate Schedule BA-1, *Billing Adjustments,* except for the Fuel Cost Recovery Factor and Asset Securitization Charge Factor:	See Sheet No. 6.105 and 6.106

The On-Peak rate shall apply to energy used during designated On-Peak Periods. The Off-Peak rate shall apply to all other energy use.

Premium Distribution Service Charge:

Where Premium Distribution Service has been established after 12/15/98 in accordance with Subpart 2.05, General Rules and Regulations Governing Electric Service, the customer shall pay a monthly charge determined under Special Provision No. 5 of this rate schedule for the costs of all additional equipment, or the customer's allocated share thereof, installed to accomplish automatic delivery transfer including all line costs necessary to connect to an alternate distribution circuit. In addition, the Base Demand Charge included in the Rate per Month section of this rate schedule shall be increased by $1.50 per kW for the cost of reserving capacity in the alternate distribution circuit.

(Continued on Page No. 2)

RATE SCHEDULE IST-2
INTERRUPTIBLE GENERAL SERVICE
OPTIONAL TIME OF USE RATE
(Continued from Page No. 1)

Rating Periods:

(a) On-Peak Periods - The designated On-Peak Periods expressed in terms of prevailing clock time shall be as follows:

(1) For the calendar months of December through February,
Monday through Friday*: 5:00 a.m. to 10:00 a.m.

(2) For all calendar months,
Monday through Friday*: 6:00 p.m. to 9:00 p.m.

* The following general holidays shall be excluded from the On-Peak Periods: New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day and Christmas. In the event the holiday occurs on a Saturday or Sunday, the adjacent weekday shall be excluded from the On-Peak Periods.

(b) Super-Off-Peak Periods - The designated Super-Off-Peak Periods expressed in terms of prevailing clock time shall be as follows:
For the calendar months of March through November,
Every day, including weekends and holidays 12:00 a.m. (midnight) to 6:00 a.m.

(c) Off-Peak Periods - The designated Off-Peak Periods shall be all periods other than the designated On-Peak and Super-Off-Peak Periods set forth in (a) and (b) above.

Determination of Billing Demands:

The billing demands shall be the following:

(a) The Base Demand shall be the maximum 30-minute kW demand established over the current and the eleven previous billing periods, but not less than 500 kW.

(b) The Mid-Peak Demand shall be the maximum 30-minute kW demand established during the designated On-Peak or Off-Peak Periods during the current billing period.

(c) The On-Peak Demand shall be the maximum 30-minute kW demand established during designated On-Peak Periods during the current billing period.

(d) The Monthly Max Demand shall be the maximum 30-minute kW demand established during the current billing period.

Delivery Voltage Credit:

When a customer takes service under this rate at a delivery voltage above standard distribution secondary voltage, the Base Demand charge hereunder shall be subject to the following credit:

For Distribution Primary Delivery Voltage:	$1.31 per kW of Monthly Max Demand
For Transmission Delivery Voltage below 230 kV:	$5.42 per kW of Monthly Max Demand
For Transmission Delivery Voltage at or above 230 kV:	$7.50 per kW of Monthly Max Demand

Note: In no event shall the total of the Demand Charges hereunder, after application of the above credit, be an amount less than zero.

Metering Voltage Adjustment:

Metering voltage will be at the option of the Company. When the Company meters at a voltage above distribution secondary, the appropriate following reduction factor shall apply to the Non-Fuel Energy Charge, Demand Charges, Interruptible Demand Credit and Delivery Voltage Credit hereunder:

Metering Voltage	Reduction Factor
Distribution Primary	1.0%
Transmission	2.0%

Power Factor:

If a customer's power factor at the time of maximum demand in the current billing period is less than 85%, the Company may adjust the Base Demand by multiplying by 85% and dividing by the resulting power factor actually established at the time of maximum demand during the current month.

(Continued on Page No. 3)

RATE SCHEDULE IST-2
INTERRUPTIBLE GENERAL SERVICE
OPTIONAL TIME OF USE RATE
(Continued from Page No. 2)

Additional Charges:

Fuel Cost Recovery Factor:	See Sheet No. 6.105
Asset Securitization Charge Factor:	See Sheet No. 6.105
Gross Receipts Tax Factor & Regulatory Assessment Fee Factor:	See Sheet No. 6.106
Right-of-Way Utilization Fee:	See Sheet No. 6.106
Municipal Tax:	See Sheet No. 6.106
Sales Tax:	See Sheet No. 6.106

Minimum Monthly Bill:

The minimum monthly bill shall be the Customer Charge and the Demand Charge for the current billing period. Where special equipment to serve the customer is required, the Company may require a specified minimum charge.

Terms of Payment:

Bills rendered hereunder are payable within the time limit specified on bill at Company-designated locations.

Term of Service:

For customers electing to take service hereunder in lieu of the otherwise applicable Rate Schedule IS-2, the term of service requirements under this optional rate schedule shall be the same as that required under Rate Schedule IS-2 provided, however, at a given location the customer shall have the right during the initial term of service to transfer to the otherwise applicable Rate Schedule IS-2 at any time. It is further provided, however, that any such customer who subsequently re-elects to take service hereunder at the same location shall be required to remain on the optional rate at that location for a minimum term of twelve (12) months.

Special Provisions:

1. When the customer increases his electrical load, which increase requires the Company to increase facilities installed for the specific use of the customer, a new Term of Service may be required under this rate at the option of the Company.

2. Customers taking service under another Company rate schedule who elect to transfer to this rate will be accepted by the Company on a first-come, first-served basis. Required equipment (metering, under frequency relay, etc.) will be installed accordingly, subject to availability. Service under this rate schedule shall commence with the first full billing period following the date of equipment installation. Before commencement of service under this rate, the Company shall exercise an interruption for purposes of testing its equipment. The Company shall also have the right to exercise at least one additional interruption each calendar year irrespective of capacity available or operating conditions. The Company will give the customer notice of the test.

3. The Company may, under the provisions of this rate, at its option, require a special contract with the customer upon the Company's filed contract form.

4. The Company will attempt to minimize interruption hereunder by purchasing power and energy from other sources during periods of normal interruption. The Company will also attempt to notify any customer, desirous of such notice, in advance when such purchases are imminent or as soon as practical thereafter where advance notice is not feasible. Similar notification will be provided upon termination of such purchases.

5. The Company will furnish service under this rate at a single voltage. Equipment to supply additional voltages or additional facilities for the use of the customer shall be furnished and maintained by the customer. The customer may request the Company to furnish such additional equipment, and the Company, at its sole option, may furnish, install, and maintain such additional equipment, charging the customer for the use thereof at the rate of 1.08% per month of the installed cost of such additional equipment.

6. Customers taking service under this interruptible rate schedule who desire to transfer to a non-interruptible rate schedule will be required to give the Company written notice at least thirty-six (36) months prior to such transfer. Such notice shall be irrevocable unless the Company and the customer shall mutually agree to void the revocation.

7. Service under this rate is not available if all or a part of the customer's load is designated by the appropriate governmental agency for use as a public shelter during periods of emergency or natural disaster.

8. Any customer who established a billing demand of less than 500 kW in any of the 12 billing periods proceeding May 1, 2002, shall be advised by the Company that the minimum billing demand of 500 kW would not apply in the event the customer exercises Special Provision No. 6 of this rate.

Stephanie A. Cuello
SENIOR COUNSEL

April 22, 2024

VIA ELECTRONIC DELIVERY

Adam J. Teitzman, Commission Clerk
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, Florida 32399-0850

Re: Ten-Year Site Plan as of December 31, 2023; Undocketed

Dear Mr. Teitzman:

Pursuant to Rule 25-22.071, F.A.C., please find enclosed for filing Duke Energy Florida, LLC's, 2024 Amended Ten-Year Site Plan. DEF discovered an inadvertent error in the coal price forecast, which caused a change to Schedules 5, 6.1, 6.2 and a portion of 9.

Thank you for your assistance in this matter and if you have any questions, please feel free to contact me at (850) 521-1425.

Sincerely,

/s/ Stephanie A. Cuello

Stephanie A. Cuello

SAC/clg
Attachments

cc: Greg Davis, GDavis@psc.state.fl.us and Phillip Ellis, PEllis@psc.state.fl.us, Division of Engineering, FPSC

Duke Energy Florida, LLC
Ten-Year Site Plan

April 2024

2024-2033

Submitted to:
Florida Public Service Commission

TABLE OF CONTENTS

TABLE OF CONTENTS (Continued)

LIST OF REQUIRED SCHEDULES

LIST OF
TABLES AND FIGURES

CODE IDENTIFICATION SHEET

Generating Unit Type

BA - Battery Storage
CC - Combined Cycle
COG - Cogeneration Facility
CT - Combustion Turbine
GT - Gas Turbine
NP - Steam Power - Nuclear
PV – Photovoltaic
SPP - Small Power Producer
SPS – Solar (PV) Plus Storage
ST - Steam Turbine - Non-Nuclear

Fuel Type

BIO – Biomass
BIT - Bituminous Coal
DFO - No. 2 Distillate Fuel Oil
MSW - Municipal Solid Waste
NG - Natural Gas
NUC - Nuclear (Uranium)
RFO - No. 6 Residual Fuel Oil
SO – Solar PV
WH - Waste Heat

Fuel Transportation

PL - Pipeline
RR - Railroad
TK - Truck
UN - Unknown
WA - Water

Future Generating Unit Status

A - Generating unit capability increased
D – Generating unit capability decreased
FC - Existing generator planned for conversion to another fuel or energy source
P - Planned for installation but not authorized; not under construction
RP - Proposed for repowering or life extension
RT - Existing generator scheduled for retirement
T - Regulatory approval received but not under construction
U - Under construction, less than or equal to 50% complete
V - Under construction, more than 50% complete

EXECUTIVE SUMMARY

Duke Energy Florida's (DEF) 2024 Ten-Year Site Plan (TYSP) provides a description of the future electric generating unit additions and retirements selected to meet projected DEF customer resource needs for 2024 through 2033. DEF's plan continues the multi-year progress in the transition to a cleaner and more cost-effective generating fleet. In the near term, DEF anticipates the expiration of high-priced legacy contracts and retirement of numerous older simple cycle combustion turbine (CT) units offset by a planned investment in new solar, storage, and solar plus storage generation. Looking out beyond the ten-year horizon, DEF anticipates the retirement of the remaining two coal fired generating units and the potential to replace most of the energy supplied by those units with energy generated from future solar generating projects.

DEF's planned investments in renewable generation will enable fuel savings for customers, energy diversification, and will continue DEF's commitment towards a lower carbon future. Through this TYSP, DEF is planning to extend the successful deployment of utility scale solar projects approved by the Florida Public Service Commission (FPSC) in 2017 and 2021, which will bring over 1,400 MW of solar generating capacity to the DEF system through early 2024. Over the remainder of the ten-year planning period, DEF projects the addition of at least 450 MW per year of utility scale solar. By the end of the period, DEF expects to have more than 6,100 MW of utility scale solar generating capacity online.

DEF's measured and steady pace of projected solar generation adoption will combine with the increasingly clean gas fired generating fleet. DEF is beginning efficiency enhancements that will reduce fleet fuel consumption while adding close to 400 MW in highly efficient combined cycle generating capacity. Even with the additional CC upgrades, DEF anticipates a reduction in the fossil fuel fired generation of approximately 1,500 MW over the planning period.

In addition to improvements to the existing asset portfolio and the planned solar, DEF continues to build upon its pilot battery program approved in 2017. This program installed 50 MW of batteries from 2021 to 2023. These batteries provide a variety of services including solar energy storage and smoothing, grid support and voltage control, and deferral of potential new distribution investments. These assets also have the capability to enable islanding to support an amount of local load in the event of grid separation. A transmission-tied grid scale battery energy storage unit is planned to be placed in service in 2027. This unit combines over 200 MWh of energy storage and a 100 MW capacity to provide grid stabilization during periods of solar volatility and energy shifting to lower cost of energy based on time of day. In addition, DEF continues to plan batteries paired with solar units in 2028-2030 to further balance the system and provide reliability resources supporting the large amount of planned solar generation.

DEF will accelerate the addition of four combustion turbines between years 2032 and 2033 that will replace some of the generation from Crystal River North that is planned to be retired in year 2034.

DEF plans to meet the power needs of its customers cost-effectively while adding an increasing portfolio of non-carbon emitting assets. The future solar and storage in this expansion plan along with increased efficiency in conventional generation provides energy diversity by reducing natural gas consumption while maintaining reliable and dispatchable capacity.

INTRODUCTION

Section 186.801 of the Florida Statutes (F.S.) requires electric generating utilities to submit a TYSP to the FPSC. The TYSP includes historical and projected data pertaining to the utility's load and resource needs as well as a review of those needs. DEF's TYSP is compiled in accordance with FPSC Rules 25-22.070 through 25-22.072, Florida Administrative Code (F.A.C.).

DEF's TYSP is based on the projections of long-term planning requirements that are dynamic in nature and subject to change. These planning documents should be used for general guidance concerning DEF's planning assumptions and projections and should not be taken as an assurance that particular events discussed in the TYSP will materialize or that particular plans will be implemented. Information and projections pertinent to periods further out in time are inherently subject to greater uncertainty.

This TYSP document contains four chapters as indicated below:

- **CHAPTER 1 - DESCRIPTION OF EXISTING FACILITIES**

  This chapter provides an overview of DEF's generating resources as well as the transmission and distribution system.

- **CHAPTER 2 - FORECAST OF ELECTRICAL POWER DEMAND AND ENERGY CONSUMPTION**

  Chapter 2 presents the history and forecast for load and peak demand as well as the forecast methodology used. Demand-Side Management (DSM) savings and fuel requirement projections are also included.

- **CHAPTER 3 - FORECAST OF FACILITIES REQUIREMENTS**

  The resource planning forecast, transmission planning forecast as well as the proposed generating facilities and bulk transmission line additions status are discussed in Chapter 3.

- **CHAPTER 4 - ENVIRONMENTAL AND LAND USE INFORMATION**

Preferred and potential site locations along with any environmental and land use information are presented in this chapter.

CHAPTER 1

DESCRIPTION OF EXISTING FACILITIES

CHAPTER 1

DESCRIPTION OF EXISTING FACILITIES

EXISTING FACILITIES OVERVIEW

OWNERSHIP

Duke Energy Florida, LLC (DEF or the Company) is a wholly owned subsidiary of Duke Energy Corporation (Duke Energy).

AREA OF SERVICE

DEF has an obligation to serve approximately 1.9 million customers in Florida. Its service area covers approximately 20,000 square miles in west central Florida and includes the densely populated areas around Orlando, as well as the cities of St. Petersburg and Clearwater. DEF is interconnected with 21 municipal and nine rural electric cooperative systems who serve additional customers in Florida. DEF is subject to the rules and regulations of the Federal Energy Regulatory Commission (FERC), the Nuclear Regulatory Commission (NRC), and the FPSC. DEF's Service Area is shown in Figure 1.1.

TRANSMISSION/DISTRIBUTION

The Company is part of a nationwide interconnected power network that enables power to be exchanged between utilities. The DEF transmission system includes approximately 5,300 circuit miles of transmission lines. The distribution system includes approximately 18,000 circuit miles of overhead distribution conductors and approximately 14,000 circuit miles of underground distribution cable.

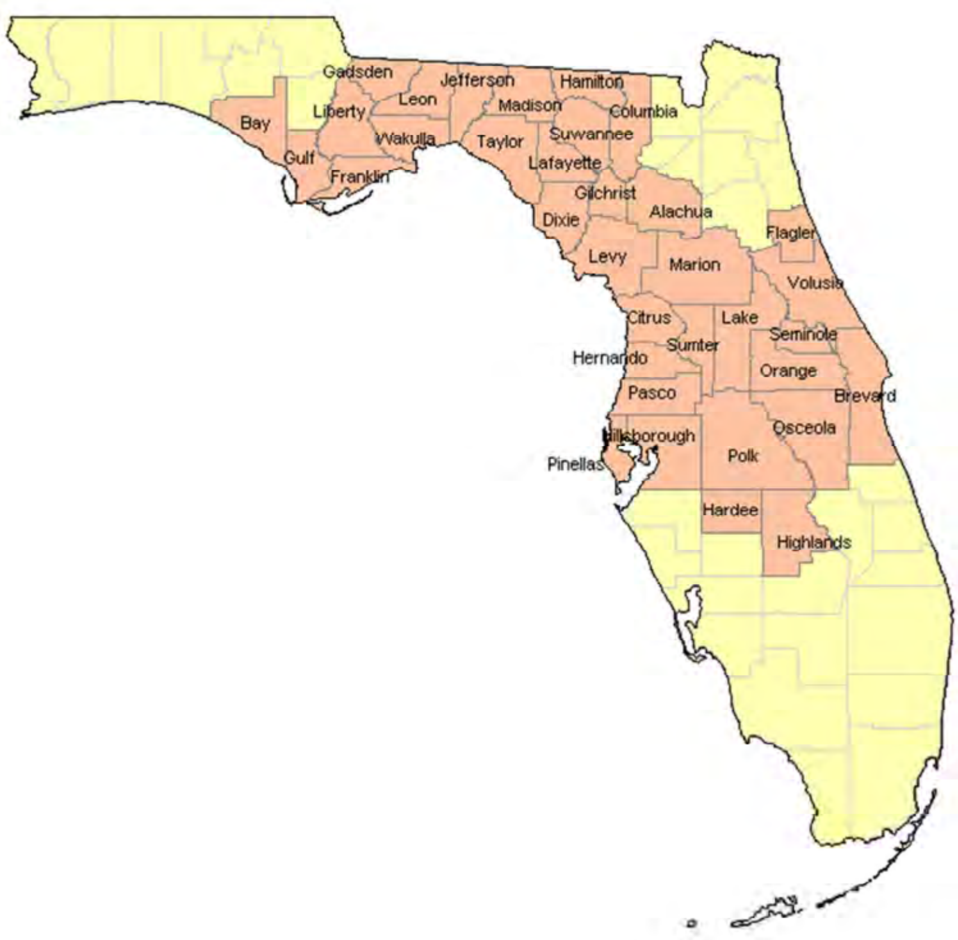
ENERGY MANAGEMENT and ENERGY EFFICIENCY

The Company's residential Energy Management program represents a demand response (DR) type of program where participating customers help manage future load growth and costs. Approximately 433,000 customers participated in the residential Energy Management program during 2023, contributing about 638 MW of winter peak-shaving capacity for use during high load periods. DEF's currently approved DSM portfolio of programs consist of five residential programs (four energy efficiency and one demand response), six commercial and industrial programs (three energy efficiency and three demand response) and one research and development program.

TOTAL CAPACITY RESOURCE

As of December 31, 2023, DEF had total summer firm capacity resources of 11,750 MW consisting of installed capacity of 10,290 MW and 1,460 MW of firm purchased power. Additional information on DEF's existing generating resources can be found in Schedule 1 and Table 3.1 (Chapter 3).

FIGURE 1.1
DUKE ENERGY FLORIDA
County Service Area Map



DUKE ENERGY FLORIDA

SCHEDULE 1
EXISTING GENERATING FACILITIES

AS OF DECEMBER 31, 2023

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
									COM'L IN-	EXPECTED	GEN. MAX.	NET CAPABILITY	
	UNIT	LOCATION	UNIT	FUEL		FUEL TRANSPORT		ALT. FUEL	SERVICE	RETIREMENT	NAMEPLATE	SUMMER	WINTER
PLANT NAME	NO.	(COUNTY)	TYPE	PRI.	ALT.	PRI.	ALT.	DAYS USE	MO./YEAR	MO./YEAR	KW	MW	MW
STEAM													
ANCLOTE	1	PASCO	ST	NG		PL			10/74		556,200	508	521
ANCLOTE	2	PASCO	ST	NG		PL			10/78		556,200	505	514
CRYSTAL RIVER	4	CITRUS	ST	BIT		WA	RR		12/82		739,260	712	721
CRYSTAL RIVER	5	CITRUS	ST	BIT		WA	RR		10/84		739,260	698	721
											Steam Total	**2,423**	**2,477**
COMBINED-CYCLE													
P L BARTOW	4	PINELLAS	CC	NG	DFO	PL	TK	*	6/09		1,254,200	1,112	1,259
CITRUS COUNTY COMBINED CYCLE	PB1	CITRUS	CC	NG		PL			10/18		985,150	807	925
CITRUS COUNTY COMBINED CYCLE	PB2	CITRUS	CC	NG		PL			11/18		985,150	803	929
HINES ENERGY COMPLEX	1	POLK	CC	NG		PL			4/99		546,500	501	521
HINES ENERGY COMPLEX	2	POLK	CC	NG	DFO	PL	TK	*	12/03		548,250	532	549
HINES ENERGY COMPLEX	3	POLK	CC	NG	DFO	PL	TK	*	11/05		561,000	523	535
HINES ENERGY COMPLEX	4	POLK	CC	NG	DFO	PL	TK	*	12/07		610,500	525	544
OSPREY ENERGY CENTER POWER PLANT	1	POLK	CC	NG		PL			5/04		644,300	245	245
TIGER BAY	1	POLK	CC	NG		PL			8/97		278,100	199	230
											CC Total	**5,247**	**5,737**
COMBUSTION TURBINE													
BARTOW	P1	PINELLAS	CT	DFO		WA		*	5/72	6/2027 **	55,400	41	50
BARTOW	P2	PINELLAS	CT	NG	DFO	PL	WA	*	6/72		55,400	41	53
BARTOW	P3	PINELLAS	CT	DFO		WA		*	6/72	6/2027 **	55,400	41	51
BARTOW	P4	PINELLAS	CT	NG	DFO	PL	WA	*	6/72		55,400	45	58
BAYBORO	P1	PINELLAS	CT	DFO		WA		*	4/73	10/2026 **	56,700	44	58
BAYBORO	P2	PINELLAS	CT	DFO		WA		*	4/73	10/2026 **	56,700	21	27
BAYBORO	P3	PINELLAS	CT	DFO		WA		*	4/73	10/2026 **	56,700	43	57
BAYBORO	P4	PINELLAS	CT	DFO		WA		*	4/73	10/2026 **	56,700	43	56
DEBARY	P2	VOLUSIA	CT	DFO		TK		*	12/75-4/76	6/2027 **	73,440	45	57
DEBARY	P3	VOLUSIA	CT	DFO		TK		*	12/75-4/76	6/2027 **	73,440	45	59
DEBARY	P4	VOLUSIA	CT	DFO		TK		*	12/75-4/76	6/2027 **	73,440	46	59
DEBARY	P5	VOLUSIA	CT	DFO		TK		*	12/75-4/76	6/2027 **	73,440	45	58
DEBARY	P6	VOLUSIA	CT	DFO		TK		*	12/75-4/76	6/2027 **	73,440	46	59
DEBARY	P7	VOLUSIA	CT	NG	DFO	PL	TK	*	10/92		103,500	74	93
DEBARY	P8	VOLUSIA	CT	NG	DFO	PL	TK	*	10/92		103,500	75	94
DEBARY	P9	VOLUSIA	CT	NG	DFO	PL	TK	*	10/92		103,500	76	94
DEBARY	P10	VOLUSIA	CT	DFO		TK		*	10/92		103,500	72	88
INTERCESSION CITY	P1	OSCEOLA	CT	DFO		PL,TK		*	5/74		56,700	45	61
INTERCESSION CITY	P2	OSCEOLA	CT	DFO		PL,TK		*	5/74		56,700	46	60
INTERCESSION CITY	P3	OSCEOLA	CT	DFO		PL,TK		*	5/74		56,700	46	61
INTERCESSION CITY	P4	OSCEOLA	CT	DFO		PL,TK		*	5/74		56,700	46	62
INTERCESSION CITY	P5	OSCEOLA	CT	DFO		PL,TK		*	5/74		56,700	45	59
INTERCESSION CITY	P6	OSCEOLA	CT	DFO		PL,TK		*	5/74		56,700	47	60
INTERCESSION CITY	P7	OSCEOLA	CT	NG	DFO	PL	PL,TK	*	10/93		103,500	78	90
INTERCESSION CITY	P8	OSCEOLA	CT	NG	DFO	PL	PL,TK	*	10/93		103,500	77	88
INTERCESSION CITY	P9	OSCEOLA	CT	NG	DFO	PL	PL,TK	*	10/93		103,500	77	88
INTERCESSION CITY	P10	OSCEOLA	CT	NG	DFO	PL	PL,TK	*	10/93		103,500	74	86
INTERCESSION CITY	P11	OSCEOLA	CT	DFO		PL,TK		*	1/97		148,500	140	161
INTERCESSION CITY	P12	OSCEOLA	CT	NG	DFO	PL	PL,TK	*	12/00		98,260	73	89
INTERCESSION CITY	P13	OSCEOLA	CT	NG	DFO	PL	PL,TK	*	12/00		98,260	73	91
INTERCESSION CITY	P14	OSCEOLA	CT	NG	DFO	PL	PL,TK	*	12/00		98,260	73	90
SUWANNEE RIVER	P1	SUWANNEE	CT	NG	DFO	PL	TK	*	10/80		65,999	48	65
SUWANNEE RIVER	P2	SUWANNEE	CT	NG	DFO	PL	TK	*	10/80		65,999	48	64
SUWANNEE RIVER	P3	SUWANNEE	CT	NG	DFO	PL	TK	*	11/80		65,999	49	65
UNIVERSITY OF FLORIDA	P1	ALACHUA	GT	NG		PL			1/94		43,000	44	50
											CT Total	**1,972**	**2,461**

* APPROXIMATELY 2 TO 3 DAYS OF OIL USE TYPICALLY TARGETED FOR ENTIRE PLANT.
** DATES FOR RETIREMENT ARE APPROXIMATE AND SUBJECT TO CHANGE

DUKE ENERGY FLORIDA

SCHEDULE 1

EXISTING GENERATING FACILITIES

AS OF DECEMBER 31, 2023

(1) PLANT NAME	(2) UNIT NO.	(3) LOCATION (COUNTY)	(4) UNIT TYPE	(5) FUEL PRI.	(6) FUEL ALT.	(7) FUEL TRANSPORT PRI.	(8) FUEL TRANSPORT ALT.	(9) ALT. FUEL DAYS USE	(10) COM'L IN-SERVICE MO./YEAR	(11) EXPECTED RETIREMENT MO./YEAR	(12) GEN. MAX. NAMEPLATE KW	(13) NET CAPABILITY SUMMER MW	(14) NET CAPABILITY WINTER MW
SOLAR													
OSCEOLA SOLAR FACILITY	PV1	OSCEOLA	PV	SO					5/16		3,800	2	0
PERRY SOLAR FACILITY	PV1	TAYLOR	PV	SO					8/16		5,100	2	0
SUWANNEE RIVER SOLAR FACILITY	PV1	SUWANNEE	PV	SO					11/17		8,800	4	0
HAMILTON SOLAR POWER PLANT	PV1	HAMILTON	PV	SO					12/18		74,900	42	0
TRENTON SOLAR POWER PLANT	PV1	GILCHRIST	PV	SO					12/19		74,900	42	0
LAKE PLACID SOLAR POWER PLANT	PV1	HIGHLANDS	PV	SO					12/19		45,000	25	0
ST PETERSBURG PIER	PV1	PINELLAS	PV	SO					12/19		350	0	0
COLUMBIA SOLAR POWER PLANT	PV1	COLUMBIA	PV	SO					3/20		74,900	42	0
DEBARY SOLAR POWER PLANT	PV1	VOLUSIA	PV	SO					5/20		74,500	33	0
SANTA FE SOLAR POWER PLANT	PV1	COLUMBIA	PV	SO					3/21		74,900	42	0
TWIN RIVERS SOLAR POWER PLANT	PV1	HAMILTON	PV	SO					3/21		74,900	42	0
DUETTE SOLAR POWER PLANT	PV1	MANATEE	PV	SO					10/21		74,500	42	0
SANDY CREEK SOLAR POWER PLANT	PV1	BAY	PV	SO					5/22		74,900	42	0
FORT GREEN SOLAR POWER PLANT	PV1	HARDEE	PV	SO					6/22		74,900	33	0
CHARLIE CREEK SOLAR POWER PLANT	PV1	HARDEE	PV	SO					8/22		74,900	42	0
BAY TRAIL SOLAR POWER PLANT	PV1	CITRUS	PV	SO					9/22		74,900	42	0
HILDRETH SOLAR POWER PLANT	PV1	SUWANNEE	PV	SO					4/23		74,900	42	0
HIGH SPRINGS SOLAR POWER PLANT	PV1	ALACHUA	PV	SO					4/23		74,900	42	0
HARDEETOWN SOLAR POWER PLANT	PV1	LEVY	PV	SO					4/23		74,900	42	0
BAY RANCH SOLAR POWER PLANT	PV1	BAY	PV	SO					4/23		74,900	42	0
											Solar Total	**648**	**0**
											TOTAL RESOURCES (MW)	**10,290**	**10,675**

(Blank Page)

CHAPTER 2

FORECAST OF ELECTRIC POWER DEMAND AND ENERGY CONSUMPTION

CHAPTER 2

FORECAST OF ELECTRIC POWER DEMAND AND ENERGY CONSUMPTION

OVERVIEW

The information presented in Schedules 2, 3, and 4 represents DEF's history and forecast of customers, energy sales (GWh), and peak demand (MW). In general, this discussion refers to DEF's base forecast.

The DEF forecast utilized economic data from July 2023. From a macro perspective, the U.S. economy was characterized by several significant trends and changes. The labor market was at full employment. The Federal Reserve had actively increased interest rates since early 2022 in an effort to control inflation (3.6% as of July 2023). Additionally, the central bank had been reducing its holdings of financial assets. Interest rates on ten-year Treasury bonds were near their expected long-term levels, and fiscal policy, despite a temporary suspension of the debt limit, was projected to be somewhat expansionary with the passage of the Inflation Reduction Act. The U.S. dollar remained strong due to monetary policy and global uncertainties. From a low in Q2 2020 to a peak in Q2 2021, inflation adjusted corporate profits remained above pre-pandemic levels. Global oil prices were expected to stay below $100 per barrel. The pandemic's impact was waning, and the ongoing Russian war's influence on global markets was predicted to decrease.

In mid-2023, Florida's economy held its position as one of the top performers in the region. Job growth had slowed slightly over the past quarter, but Florida had outperformed nearly all states in the region during the past six- and 12-month periods. Every major industry had been performing well throughout the year, with tourism, the state's core driver, leading in job creation. Healthcare and utilities also stood out. Net hiring in finance had slowed due to market instability. The unemployment rate had remained steady below its previous cyclical low, despite a 5% growth in the labor force since its pre-pandemic level. While the housing market had cooled, there were signs of optimism, including a monthly increase in house prices in February. Single-family permit issuance had decreased from the previous year's pace, but the multifamily market was on track for its strongest year in decades. Florida was expected to continue performing well, but the impact of higher prices and elevated interest rates would likely slow job creation and put pressure on the housing market. The vital tourism industry would provide less support as well. In the long term, Florida's advantageous factors such as low costs, favorable weather, and an improving industrial composition would drive above-average job and income growth.

Historical 29 county service area household, population, and people per household data were used for the Base Case, High Case, and Low Case service area population projections. The DEF service area population was estimated to have grown at an average ten-year compound annual growth rate (CAGR) of 1.56% from 2014-2023 (Schedule 2.1.1 Column 2). The projected DEF service area population growth weakened to a level of 1.20% over the 2024-2033 period due to higher mortality rates among aging baby-boomers. The rate of residential customer growth, which averaged 1.72% per year over the historical ten-year period, is expected to continue at an average of 1.72%. The total number of DEF customers grew from 1.69 million in 2014 to 1.96 million in 2023, an increase of 269,130 or 1.65% annual growth rate. The projected number of additional total customers between 2024 and 2033 is projected to be 320,423 for a 1.67% annual growth rate.

Responses to the pandemic, which changed the patterns of class energy consumption, have reverted to pre-COVID usage characteristics. Remote work in the DEF service area still exists but at a much smaller level than that reached early in the pandemic. These changes imply a decrease in residential energy consumption which can be seen in the projected annual growth rate for average kWh consumption per customer (Schedule 2.1.1 Column 6). The projected ten-year annual growth rate for average kWh consumption per customer is -0.37% vs. a historical rate of -0.21%. Residential use per customer continues to decline due to higher energy prices/inflation, energy efficiency and rooftop solar adoption. In terms of annual residential sales growth, measured in GWh (1.34% projected vs. 1.51% historical), sustained residential customer growth (1.72% projected vs. 1.72% historical) is working to offset the declining use per customer. Labor shortages and the low cost of living in Florida relative to other parts of the U.S. also continue to attract people to the state as per capita income adjusted for cost of living is more favorable in Florida than other parts of the U.S. Florida continues to be a tourist attraction and retirement haven. Given the increase in the retirement population in the U.S. over the near term as the "Baby Boomer" generation reaches 65 and older, the retirement cohort in Florida should increase significantly over the next five to ten years. Increases in commercial and industrial class energy requirements have returned as well. Commercial sales growth (1.57% projected vs. 0.61% historical) is projected to be driven by the return to normal operating hours, population growth, and consumer spending/tourism. Sales to the industrial class (0.20% projected vs. 0.43% historical) were helped in 2023 by the Nucor Steel plant startup, Mosaic's operations growth, and Trulieve's startup. On the other hand, in November 2023, GP Cellulose shut down its Perry, FL manufacturing site. In February 2024, another major customer announced that they will be installing 6 MW of customer-owned CHP. These two customers accounted for nearly 5% of 2023 Industrial sales. In 2033, several major mining customers will deplete their resources through their operations. This is discussed in further detail under "General Assumptions" page 2-33. Over a nine-year period from 2024-2032, the industrial GWh growth rate was 1.08%. Long-term, total retail sales continue to increase (1.30% projected vs. 1.03% historical) but remain subject to uncertain economic conditions such as increasing rates, unemployment, and energy prices.

From 2014 to 2023, net energy for load (NEL) increased by 0.81% per year (Schedule 2.3.1 Column 4). The average projected ten-year CAGR for NEL is 0.91%. While Sales for Resale experienced an average annual decrease of -26.45% during the forecast period, sustained retail load growth offsets the loss of these contracts. Long term, DEF Sales for Resale energy sales are projected to essentially disappear.

During the 2014 to 2023 historical period the DEF summer net firm demand (Schedule 3.1.1 Column 10) increased from 8,523 MW to 9,352 MW, an average annual ten-year increase of 1.04%. This increase was driven by the ten-year average customer growth of 1.65% per year. The Wholesale summer peak remained relatively flat with a ten-year CAGR of 0.18%. Wholesale load was offset by higher conservation levels and additional residential demand response capability (Schedule 3.1.1). Going forward, the projected total DEF summer net firm demand, 2024 – 2033, grows at a slightly lower average annual rate of 0.96% due to declining Sales for Resale. The historical DEF firm winter peak ten-year CAGR was 1.00% per year driven by customer growth. Projected total DEF winter net firm demand remained positive with an average annual rate of 0.42% between 2024 and 2033 due to a reduction in the projected Sales for Resale peak demand

(-8.03% annual average decline), offset by expected ten-year growth in Retail winter peak of 1.06%. Both summer and winter Sales for Resale peak demand are expected to decline significantly towards the end of the ten-year projection.

DEF continues to provide alternate “high” and “low” forecasts for customers, energy, and peak demand, recognizing that the economic future is uncertain due to the tightening of monetary policy or other unknown events. The Fed’s goal has been a “soft landing” where inflation is reigned in to 2% without sending the economy into a recession. Moody’s S1 and S3 (high & low) Florida economic scenarios were used to provide a range of economic variables around the Base Case scenario. These were combined with high and low peak weather scenarios for each season and high and low population growth scenarios from Moody’s.

ENERGY CONSUMPTION AND DEMAND FORECAST SCHEDULES

The below schedules have been provided to represent DEF's expectations for a Base Case as well as reasonable High and Low forecast scenarios for resource planning purposes. (Base-B, High-H and Low-L):

SCHEDULE	DESCRIPTION
2.1, 2.2 and 2.3	History and Forecast of Energy Consumption and Number of Customers by Customer Class (B, H and L)
3.1	History and Forecast of Base Summer Peak Demand (MW) (B, H and L)
3.2	History and Forecast of Base Winter Peak Demand (MW) (B, H and L)
3.3	History and Forecast of Base Annual Net Energy for Load (GWh) (B, H and L)
4	Previous Year Actual and Two-Year Forecast of Peak Demand and Net Energy for Load by Month (B, H and L)

DUKE ENERGY FLORIDA

SCHEDULE 2.1.1

HISTORY AND FORECAST OF ENERGY CONSUMPTION AND

NUMBER OF CUSTOMERS BY CUSTOMER CLASS

BASE CASE FORECAST

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
	RURAL AND RESIDENTIAL					COMMERCIAL		
YEAR	DEF POPULATION	MEMBERS PER HOUSEHOLD	GWh	AVERAGE NO. OF CUSTOMERS	AVERAGE KWh CONSUMPTION PER CUSTOMER	GWh	AVERAGE NO. OF CUSTOMERS	AVERAGE KWh CONSUMPTION PER CUSTOMER
HISTORY:								
2014	3,747,160	2.492	19,003	1,503,758	12,637	11,789	167,253	70,485
2015	3,794,138	2.489	19,932	1,524,605	13,074	12,070	169,147	71,359
2016	3,837,436	2.485	20,265	1,543,967	13,126	12,094	170,999	70,724
2017	3,906,975	2.483	19,791	1,573,260	12,579	11,918	173,695	68,612
2018	3,968,241	2.485	20,636	1,597,132	12,920	12,172	175,848	69,216
2019	4,037,435	2.483	20,775	1,626,117	12,776	12,198	178,036	68,514
2020	4,089,498	2.471	21,459	1,655,304	12,964	11,522	179,666	64,129
2021	4,130,929	2.448	21,192	1,687,471	12,558	11,785	182,195	64,686
2022	4,253,325	2.473	21,508	1,719,905	12,505	12,220	184,453	66,248
2023	4,308,553	2.457	21,750	1,753,583	12,403	12,450	186,524	66,749
FORECAST:								
2024	4,338,254	2.439	21,660	1,778,702	12,177	12,031	189,760	63,400
2025	4,383,772	2.420	21,850	1,811,476	12,062	12,232	192,439	63,564
2026	4,431,461	2.403	21,583	1,844,137	11,704	12,268	195,108	62,879
2027	4,481,068	2.388	21,717	1,876,494	11,573	12,383	197,753	62,617
2028	4,534,352	2.375	21,981	1,909,201	11,513	12,599	200,426	62,859
2029	4,591,824	2.364	22,446	1,942,396	11,556	12,849	203,140	63,252
2030	4,651,193	2.354	22,949	1,975,868	11,614	13,097	205,875	63,617
2031	4,711,426	2.345	23,390	2,009,137	11,642	13,322	208,595	63,865
2032	4,772,194	2.337	23,646	2,042,017	11,580	13,568	211,282	64,217
2033	4,830,765	2.329	24,422	2,074,180	11,774	13,847	213,911	64,734

DUKE ENERGY FLORIDA

SCHEDULE 2.1.2
HISTORY AND FORECAST OF ENERGY CONSUMPTION AND
NUMBER OF CUSTOMERS BY CUSTOMER CLASS
HIGH CASE FORECAST

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
	RURAL AND RESIDENTIAL					COMMERCIAL		
YEAR	DEF POPULATION	MEMBERS PER HOUSEHOLD	GWh	AVERAGE NO. OF CUSTOMERS	AVERAGE KWh CONSUMPTION PER CUSTOMER	GWh	AVERAGE NO. OF CUSTOMERS	AVERAGE KWh CONSUMPTION PER CUSTOMER
HISTORY:								
2014	3,747,160	2.492	19,003	1,503,758	12,637	11,789	167,253	70,485
2015	3,794,138	2.489	19,932	1,524,605	13,074	12,070	169,147	71,359
2016	3,837,436	2.485	20,265	1,543,967	13,126	12,094	170,999	70,724
2017	3,906,975	2.483	19,791	1,573,260	12,579	11,918	173,695	68,612
2018	3,968,241	2.485	20,636	1,597,132	12,920	12,172	175,848	69,216
2019	4,037,435	2.483	20,775	1,626,117	12,776	12,198	178,036	68,514
2020	4,089,498	2.471	21,459	1,655,304	12,964	11,522	179,666	64,129
2021	4,130,929	2.448	21,192	1,687,471	12,558	11,785	182,195	64,686
2022	4,253,325	2.473	21,508	1,719,905	12,505	12,220	184,453	66,248
2023	4,308,553	2.457	21,750	1,753,583	12,403	12,450	186,524	66,749
FORECAST:								
2024	4,352,608	2.439	24,377	1,784,587	13,660	12,719	190,241	66,858
2025	4,413,787	2.420	24,708	1,823,879	13,547	12,977	193,453	67,080
2026	4,469,921	2.403	24,607	1,860,142	13,228	13,052	196,417	66,452
2027	4,526,156	2.388	24,808	1,895,375	13,088	13,213	199,296	66,301
2028	4,586,538	2.375	25,175	1,931,174	13,036	13,444	202,222	66,484
2029	4,651,704	2.364	25,613	1,967,726	13,017	13,650	205,210	66,516
2030	4,719,116	2.354	26,146	2,004,722	13,042	13,880	208,234	66,658
2031	4,786,708	2.345	26,627	2,041,240	13,045	14,107	211,218	66,790
2032	4,853,400	2.337	26,977	2,076,765	12,990	14,351	214,122	67,024
2033	4,916,610	2.329	27,723	2,111,039	13,133	14,617	216,923	67,382

DUKE ENERGY FLORIDA

SCHEDULE 2.1.3

HISTORY AND FORECAST OF ENERGY CONSUMPTION AND
NUMBER OF CUSTOMERS BY CUSTOMER CLASS

LOW CASE FORECAST

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
	RURAL AND RESIDENTIAL					COMMERCIAL		
YEAR	DEF POPULATION	MEMBERS PER HOUSEHOLD	GWh	AVERAGE NO. OF CUSTOMERS	AVERAGE KWh CONSUMPTION PER CUSTOMER	GWh	AVERAGE NO. OF CUSTOMERS	AVERAGE KWh CONSUMPTION PER CUSTOMER
HISTORY:								
2014	3,747,160	2.492	19,003	1,503,758	12,637	11,789	167,253	70,485
2015	3,794,138	2.489	19,932	1,524,605	13,074	12,070	169,147	71,359
2016	3,837,436	2.485	20,265	1,543,967	13,126	12,094	170,999	70,724
2017	3,906,975	2.483	19,791	1,573,260	12,579	11,918	173,695	68,612
2018	3,968,241	2.485	20,636	1,597,132	12,920	12,172	175,848	69,216
2019	4,037,435	2.483	20,775	1,626,117	12,776	12,198	178,036	68,514
2020	4,089,498	2.471	21,459	1,655,304	12,964	11,522	179,666	64,129
2021	4,130,929	2.448	21,192	1,687,471	12,558	11,785	182,195	64,686
2022	4,253,325	2.473	21,508	1,719,905	12,505	12,220	184,453	66,248
2023	4,308,553	2.457	21,750	1,753,583	12,403	12,450	186,524	66,749
FORECAST:								
2024	4,336,457	2.439	19,369	1,777,965	10,894	11,583	189,700	61,060
2025	4,377,461	2.420	19,473	1,808,868	10,765	11,679	192,226	60,757
2026	4,415,587	2.403	19,370	1,837,531	10,541	11,828	194,569	60,792
2027	4,453,353	2.388	19,550	1,864,888	10,483	12,021	196,805	61,082
2028	4,496,433	2.375	19,840	1,893,235	10,479	12,251	199,121	61,527
2029	4,546,275	2.364	20,183	1,923,128	10,495	12,459	201,565	61,811
2030	4,600,010	2.354	20,572	1,954,125	10,528	12,693	204,098	62,191
2031	4,655,643	2.345	20,909	1,985,349	10,532	12,908	206,650	62,464
2032	4,711,960	2.337	21,129	2,016,243	10,479	13,139	209,175	62,812
2033	4,767,593	2.329	21,739	2,047,056	10,620	13,388	211,694	63,242

DUKE ENERGY FLORIDA

SCHEDULE 2.2.1
HISTORY AND FORECAST OF ENERGY CONSUMPTION AND
NUMBER OF CUSTOMERS BY CUSTOMER CLASS
BASE CASE FORECAST

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
	INDUSTRIAL						
YEAR	GWh	AVERAGE NO. OF CUSTOMERS	AVERAGE KWh CONSUMPTION PER CUSTOMER	RAILROADS AND RAILWAYS GWh	STREET & HIGHWAY LIGHTING GWh	OTHER SALES TO PUBLIC AUTHORITIES GWh	TOTAL SALES TO ULTIMATE CONSUMERS GWh
HISTORY:							
2014	3,267	2,280	1,432,895	0	25	3,157	37,240
2015	3,293	2,243	1,468,123	0	24	3,234	38,553
2016	3,197	2,178	1,467,860	0	24	3,194	38,774
2017	3,120	2,137	1,459,991	0	24	3,171	38,023
2018	3,107	2,080	1,493,750	0	24	3,206	39,144
2019	2,963	2,025	1,463,210	0	24	3,227	39,187
2020	3,147	1,999	1,574,287	0	23	3,079	39,230
2021	3,292	1,978	1,664,307	0	24	3,158	39,451
2022	3,508	1,868	1,877,916	0	33	3,244	40,512
2023	3,396	1,773	1,915,141	0	31	3,205	40,832
FORECAST:							
2024	3,230	1,786	1,808,343	0	31	3,111	40,063
2025	3,360	1,765	1,903,655	0	31	3,185	40,658
2026	3,423	1,758	1,946,910	0	30	3,185	40,489
2027	3,453	1,756	1,966,388	0	29	3,196	40,777
2028	3,507	1,759	1,993,696	0	29	3,220	41,336
2029	3,500	1,762	1,986,265	0	28	3,234	42,057
2030	3,509	1,764	1,989,180	0	28	3,249	42,832
2031	3,515	1,767	1,989,291	0	27	3,239	43,493
2032	3,523	1,772	1,987,977	0	26	3,232	43,995
2033	3,288	1,776	1,851,436	0	26	3,231	44,815

DUKE ENERGY FLORIDA

SCHEDULE 2.2.2
HISTORY AND FORECAST OF ENERGY CONSUMPTION AND
NUMBER OF CUSTOMERS BY CUSTOMER CLASS
HIGH CASE FORECAST

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
	INDUSTRIAL						
YEAR	GWh	AVERAGE NO. OF CUSTOMERS	AVERAGE KWh CONSUMPTION PER CUSTOMER	RAILROADS AND RAILWAYS GWh	STREET & HIGHWAY LIGHTING GWh	OTHER SALES TO PUBLIC AUTHORITIES GWh	TOTAL SALES TO ULTIMATE CONSUMERS GWh
HISTORY:							
2014	3,267	2,280	1,432,895	0	25	3,157	37,240
2015	3,293	2,243	1,468,123	0	24	3,234	38,553
2016	3,197	2,178	1,467,860	0	24	3,194	38,774
2017	3,120	2,137	1,459,991	0	24	3,171	38,023
2018	3,107	2,080	1,493,750	0	24	3,206	39,144
2019	2,963	2,025	1,463,210	0	24	3,227	39,187
2020	3,147	1,999	1,574,287	0	23	3,079	39,230
2021	3,292	1,978	1,664,307	0	24	3,158	39,451
2022	3,508	1,868	1,877,916	0	33	3,244	40,512
2023	3,396	1,773	1,915,141	0	31	3,205	40,832
FORECAST:							
2024	3,266	1,786	1,828,571	0	31	3,177	43,570
2025	3,398	1,765	1,924,953	0	31	3,251	44,363
2026	3,460	1,758	1,967,978	0	30	3,249	44,398
2027	3,489	1,756	1,986,894	0	29	3,254	44,794
2028	3,543	1,759	2,014,133	0	29	3,275	45,465
2029	3,536	1,762	2,006,629	0	28	3,277	46,104
2030	3,545	1,764	2,009,498	0	28	3,284	46,883
2031	3,551	1,767	2,009,524	0	27	3,268	47,580
2032	3,558	1,772	2,008,105	0	26	3,254	48,168
2033	3,324	1,776	1,871,458	0	26	3,246	48,936

DUKE ENERGY FLORIDA

SCHEDULE 2.2.3

HISTORY AND FORECAST OF ENERGY CONSUMPTION AND
NUMBER OF CUSTOMERS BY CUSTOMER CLASS

LOW CASE FORECAST

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
	INDUSTRIAL						
YEAR	GWh	AVERAGE NO. OF CUSTOMERS	AVERAGE KWh CONSUMPTION PER CUSTOMER	RAILROADS AND RAILWAYS GWh	STREET & HIGHWAY LIGHTING GWh	OTHER SALES TO PUBLIC AUTHORITIES GWh	TOTAL SALES TO ULTIMATE CONSUMERS GWh
HISTORY:							
2014	3,267	2,280	1,432,895	0	25	3,157	37,240
2015	3,293	2,243	1,468,123	0	24	3,234	38,553
2016	3,197	2,178	1,467,860	0	24	3,194	38,774
2017	3,120	2,137	1,459,991	0	24	3,171	38,023
2018	3,107	2,080	1,493,750	0	24	3,206	39,144
2019	2,963	2,025	1,463,210	0	24	3,227	39,187
2020	3,147	1,999	1,574,287	0	23	3,079	39,230
2021	3,292	1,978	1,664,307	0	24	3,158	39,451
2022	3,508	1,868	1,877,916	0	33	3,244	40,512
2023	3,396	1,773	1,915,141	0	31	3,205	40,832
FORECAST:							
2024	3,202	1,786	1,792,981	0	31	3,030	37,216
2025	3,334	1,765	1,888,814	0	31	3,098	37,615
2026	3,400	1,758	1,934,233	0	30	3,086	37,715
2027	3,432	1,756	1,954,492	0	29	3,089	38,122
2028	3,487	1,759	1,982,346	0	29	3,106	38,712
2029	3,480	1,762	1,974,753	0	28	3,118	39,268
2030	3,488	1,764	1,977,382	0	28	3,134	39,914
2031	3,494	1,767	1,977,407	0	27	3,116	40,454
2032	3,502	1,772	1,976,094	0	26	3,102	40,898
2033	3,267	1,776	1,839,499	0	26	3,094	41,515

DUKE ENERGY FLORIDA

SCHEDULE 2.3.1
HISTORY AND FORECAST OF ENERGY CONSUMPTION AND
NUMBER OF CUSTOMERS BY CUSTOMER CLASS
BASE CASE FORECAST

(1)	(2)	(3)	(4)	(5)	(6)
YEAR	SALES FOR RESALE GWh	UTILITY USE & LOSSES GWh	NET ENERGY FOR LOAD GWh	OTHER CUSTOMERS (AVERAGE NO.)	TOTAL NO. OF CUSTOMERS
HISTORY:					
2014	1,333	2,402	40,975	25,800	1,699,091
2015	1,243	2,484	42,280	25,866	1,721,861
2016	1,803	2,277	42,854	26,005	1,743,149
2017	2,196	2,700	42,919	26,248	1,775,340
2018	2,304	2,776	44,224	26,504	1,801,564
2019	2,910	2,704	44,801	26,707	1,832,885
2020	2,887	2,697	44,814	26,845	1,863,814
2021	3,302	2,311	45,064	27,082	1,898,726
2022	3,673	1,956	46,141	26,834	1,933,060
2023	1,396	1,821	44,049	26,343	1,968,222
FORECAST:					
2024	1,119	2,237	43,418	26,304	1,996,552
2025	904	1,956	43,519	26,402	2,032,082
2026	904	2,190	43,584	26,501	2,067,504
2027	900	2,098	43,775	26,586	2,102,589
2028	889	2,279	44,504	26,680	2,138,066
2029	887	2,177	45,121	26,765	2,174,063
2030	887	2,258	45,977	26,847	2,210,354
2031	70	2,260	45,824	26,926	2,246,425
2032	71	2,536	46,602	27,014	2,282,085
2033	70	2,209	47,094	27,110	2,316,977

DUKE ENERGY FLORIDA

SCHEDULE 2.3.2
HISTORY AND FORECAST OF ENERGY CONSUMPTION AND
NUMBER OF CUSTOMERS BY CUSTOMER CLASS
HIGH CASE FORECAST

(1)	(2)	(3)	(4)	(5)	(6)
YEAR	SALES FOR RESALE GWh	UTILITY USE & LOSSES GWh	NET ENERGY FOR LOAD GWh	OTHER CUSTOMERS (AVERAGE NO.)	TOTAL NO. OF CUSTOMERS
HISTORY:					
2014	1,333	2,402	40,975	25,800	1,699,091
2015	1,243	2,484	42,280	25,866	1,721,861
2016	1,803	2,277	42,854	26,005	1,743,149
2017	2,196	2,700	42,919	26,248	1,775,340
2018	2,304	2,776	44,224	26,504	1,801,564
2019	2,910	2,704	44,801	26,707	1,832,885
2020	2,887	2,697	44,814	26,845	1,863,814
2021	3,302	2,311	45,064	27,082	1,898,726
2022	3,673	1,956	46,141	26,834	1,933,060
2023	1,396	1,821	44,049	26,343	1,968,222
FORECAST:					
2024	1,119	2,799	47,488	26,108	2,002,722
2025	904	2,584	47,852	26,148	2,045,245
2026	904	2,775	48,077	26,243	2,084,560
2027	900	2,731	48,425	26,321	2,122,748
2028	889	2,894	49,248	26,401	2,161,556
2029	887	2,823	49,814	26,432	2,201,130
2030	887	2,902	50,671	26,474	2,241,194
2031	70	2,922	50,572	26,524	2,280,749
2032	71	3,136	51,375	26,570	2,319,229
2033	70	2,905	51,911	26,626	2,356,364

DUKE ENERGY FLORIDA

SCHEDULE 2.3.3
HISTORY AND FORECAST OF ENERGY CONSUMPTION AND
NUMBER OF CUSTOMERS BY CUSTOMER CLASS
LOW CASE FORECAST

(1)	(2)	(3)	(4)	(5)	(6)
YEAR	SALES FOR RESALE GWh	UTILITY USE & LOSSES GWh	NET ENERGY FOR LOAD GWh	OTHER CUSTOMERS (AVERAGE NO.)	TOTAL NO. OF CUSTOMERS
HISTORY:					
2014	1,333	2,402	40,975	25,800	1,699,091
2015	1,243	2,484	42,280	25,866	1,721,861
2016	1,803	2,277	42,854	26,005	1,743,149
2017	2,196	2,700	42,919	26,248	1,775,340
2018	2,304	2,776	44,224	26,504	1,801,564
2019	2,910	2,704	44,801	26,707	1,832,885
2020	2,887	2,697	44,814	26,845	1,863,814
2021	3,302	2,311	45,064	27,082	1,898,726
2022	3,673	1,956	46,141	26,834	1,933,060
2023	1,396	1,821	44,049	26,343	1,968,222
FORECAST:					
2024	1,119	1,760	40,094	26,056	1,995,507
2025	904	1,512	40,031	26,062	2,028,921
2026	904	1,688	40,308	26,038	2,059,896
2027	900	1,640	40,662	26,071	2,089,520
2028	889	1,782	41,383	26,118	2,120,233
2029	887	1,701	41,856	26,217	2,152,672
2030	887	1,762	42,564	26,318	2,186,305
2031	70	1,770	42,294	26,364	2,220,130
2032	71	1,961	42,929	26,405	2,253,595
2033	70	1,732	43,317	26,471	2,286,997

DUKE ENERGY FLORIDA

SCHEDULE 3.1.1

HISTORY AND FORECAST OF SUMMER PEAK DEMAND (MW)

BASE CASE FORECAST

(1) YEAR	(2) TOTAL	(3) WHOLESALE	(4) RETAIL	(5) INTERRUPTIBLE	(6) RESIDENTIAL LOAD MANAGEMENT	(7) RESIDENTIAL CONSERVATION	(8) COMM. / IND. LOAD MANAGEMENT	(9) COMM. / IND. CONSERVATION	(OTH) OTHER DEMAND REDUCTIONS	(10) NET FIRM DEMAND
HISTORY:										
2014	10,067	814	9,253	232	355	404	108	313	132	8,523
2015	10,058	772	9,286	303	360	435	124	324	80	8,431
2016	10,530	893	9,637	235	366	466	100	339	80	8,946
2017	10,220	808	9,412	203	342	498	95	349	80	8,653
2018	10,271	812	9,459	257	386	532	83	387	80	8,545
2019	11,029	1021	10,008	230	394	566	86	414	80	9,260
2020	10,765	901	9,864	250	393	599	83	440	80	8,921
2021	10,835	1,010	9,825	375	394	623	85	451	80	8,826
2022	11,012	1,045	9,966	341	361	513	85	441	80	9,190
2023	11,357	827	10,530	476	352	550	88	459	80	9,352
FORECAST:										
2024	10,958	730	10,228	402	358	566	91	461	80	9,000
2025	10,824	451	10,372	402	364	581	94	467	80	8,836
2026	10,805	451	10,354	402	370	593	97	473	80	8,790
2027	10,822	451	10,371	402	376	605	100	477	80	8,781
2028	10,969	451	10,518	402	377	618	103	480	80	8,908
2029	11,174	451	10,723	402	378	630	107	484	80	9,093
2030	11,361	451	10,910	402	379	642	110	488	80	9,260
2031	11,493	401	11,093	402	380	653	113	492	80	9,374
2032	11,733	401	11,332	402	381	663	116	496	80	9,595
2033	11,967	401	11,566	402	382	674	119	499	80	9,811

Historical Values (2014 - 2023):

Col. (2) = recorded peak + implemented load control + residential and commercial/industrial conservation and customer-owned self-service cogeneration.

Cols. (5) - (9) = Represent total cumulative capabilities at peak. Col. (8) includes commercial load management and standby generation.

Col. (OTH) =Customer-owned self-service cogeneration.

Col. (10) = (2) - (5) - (6) - (7) - (8) - (9) - (OTH).

Projected Values (2024 - 2033):

Cols. (2) - (4) = forecasted peak without load control, cumulative conservation, and customer-owned self-service cogeneration.

Cols. (5) - (9) = cumulative conservation and load control capabilities at peak. Col. (8) includes commercial load management and standby generation.

Col. (OTH) = customer-owned self-service cogeneration.

Col. (10) = (2) - (5) - (6) - (7) - (8) - (9) - (OTH).

DUKE ENERGY FLORIDA

SCHEDULE 3.1.2
HISTORY AND FORECAST OF SUMMER PEAK DEMAND (MW)
HIGH CASE FORECAST

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(OTH)	(10)
YEAR	TOTAL	WHOLESALE	RETAIL	INTERRUPTIBLE	RESIDENTIAL LOAD MANAGEMENT	RESIDENTIAL CONSERVATION	COMM. / IND. LOAD MANAGEMENT	COMM. / IND. CONSERVATION	OTHER DEMAND REDUCTIONS	NET FIRM DEMAND
HISTORY:										
2014	10,067	814	9,253	232	355	404	108	313	132	8,523
2015	10,058	772	9,286	303	360	435	124	324	80	8,431
2016	10,530	893	9,637	235	366	466	100	339	80	8,946
2017	10,220	808	9,412	203	342	498	95	349	80	8,653
2018	10,271	812	9,459	257	386	532	83	387	80	8,545
2019	11,029	1,021	10,008	230	394	566	86	414	80	9,260
2020	10,765	901	9,864	250	393	599	83	440	80	8,921
2021	10,835	1,010	9,825	375	394	623	85	451	80	8,826
2022	11,012	1,045	9,966	341	361	513	85	441	80	9,190
2023	11,357	827	10,530	476	352	550	88	459	80	9,352
FORECAST:										
2024	11,456	730	10,726	402	358	566	91	461	80	9,498
2025	11,362	451	10,911	402	364	581	94	467	80	9,375
2026	11,371	451	10,920	402	370	593	97	473	80	9,356
2027	11,415	451	10,964	402	376	605	100	477	80	9,375
2028	11,575	451	11,124	402	377	618	103	480	80	9,514
2029	11,751	451	11,300	402	378	630	107	484	80	9,670
2030	11,947	451	11,496	402	379	642	110	488	80	9,847
2031	12,461	401	12,060	402	380	653	113	492	80	10,341
2032	12,314	401	11,913	402	381	663	116	496	80	10,176
2033	12,555	401	12,154	402	382	674	119	499	80	10,399

Historical Values (2014 - 2023):

Col. (2) = recorded peak + implemented load control + residential and commercial/industrial conservation and customer-owned self-service cogeneration.

Cols. (5) - (9) = Represent total cumulative capabilities at peak. Col. (8) includes commercial load management and standby generation.

Col. (OTH) =Customer-owned self-service cogeneration.

Col. (10) = (2) - (5) - (6) - (7) - (8) - (9) - (OTH).

Projected Values (2024 - 2033):

Cols. (2) - (4) = forecasted peak without load control, cumulative conservation, and customer-owned self-service cogeneration.

Cols. (5) - (9) = cumulative conservation and load control capabilities at peak. Col. (8) includes commercial load management and standby generation.

Col. (OTH) = customer-owned self-service cogeneration.

Col. (10) = (2) - (5) - (6) - (7) - (8) - (9) - (OTH).

DUKE ENERGY FLORIDA

SCHEDULE 3.1.3

HISTORY AND FORECAST OF SUMMER PEAK DEMAND (MW)

LOW CASE FORECAST

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(OTH)	(10)
YEAR	TOTAL	WHOLESALE	RETAIL	INTERRUPTIBLE	RESIDENTIAL LOAD MANAGEMENT	RESIDENTIAL CONSERVATION	COMM. / IND. LOAD MANAGEMENT	COMM. / IND. CONSERVATION	OTHER DEMAND REDUCTIONS	NET FIRM DEMAND
HISTORY:										
2014	10,067	814	9,253	232	355	404	108	313	132	8,523
2015	10,058	772	9,286	303	360	435	124	324	80	8,431
2016	10,530	893	9,637	235	366	466	100	339	80	8,946
2017	10,220	808	9,412	203	342	498	95	349	80	8,653
2018	10,271	812	9,459	257	386	532	83	387	80	8,545
2019	11,029	1,021	10,008	230	394	566	86	414	80	9,260
2020	10,765	901	9,864	250	393	599	83	440	80	8,921
2021	10,835	1,010	9,825	375	394	623	85	451	80	8,826
2022	11,012	1,045	9,966	341	361	513	85	441	80	9,190
2023	11,357	827	10,530	476	352	550	88	459	80	9,352
FORECAST:										
2024	10,505	730	9,776	402	358	566	91	461	80	8,547
2025	10,360	451	9,909	402	364	581	94	467	80	8,373
2026	10,391	451	9,940	402	370	593	97	473	80	8,376
2027	10,444	451	9,992	402	376	605	100	477	80	8,403
2028	10,592	451	10,141	402	377	618	103	480	80	8,532
2029	10,774	451	10,323	402	378	630	107	484	80	8,693
2030	10,926	451	10,475	402	379	642	110	488	80	8,825
2031	11,407	401	11,006	402	380	653	113	492	80	9,287
2032	11,621	401	11,220	402	381	663	116	496	80	9,483
2033	11,476	401	11,075	402	382	674	119	499	80	9,320

Historical Values (2014 - 2023):

Col. (2) = recorded peak + implemented load control + residential and commercial/industrial conservation and customer-owned self-service cogeneration.

Cols. (5) - (9) = Represent total cumulative capabilities at peak. Col. (8) includes commercial load management and standby generation.

Col. (OTH) =Customer-owned self-service cogeneration.

Col. (10) = (2) - (5) - (6) - (7) - (8) - (9) - (OTH).

Projected Values (2024 - 2033):

Cols. (2) - (4) = forecasted peak without load control, cumulative conservation, and customer-owned self-service cogeneration.

Cols. (5) - (9) = cumulative conservation and load control capabilities at peak. Col. (8) includes commercial load management and standby generation.

Col. (OTH) = customer-owned self-service cogeneration.

Col. (10) = (2) - (5) - (6) - (7) - (8) - (9) - (OTH).

DUKE ENERGY FLORIDA

SCHEDULE 3.2.1
HISTORY AND FORECAST OF WINTER PEAK DEMAND (MW)
BASE CASE FORECAST

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(OTH)	(10)
YEAR	TOTAL	WHOLESALE	RETAIL	INTERRUPTIBLE	RESIDENTIAL LOAD MANAGEMENT	RESIDENTIAL CONSERVATION	COMM. / IND. LOAD MANAGEMENT	COMM. / IND. CONSERVATION	OTHER DEMAND REDUCTIONS	NET FIRM DEMAND
HISTORY:										
2013/14	9,467	658	8,809	257	654	785	101	229	219	7,222
2014/15	10,648	1035	9,613	273	658	815	109	236	237	8,319
2015/16	9,678	1275	8,403	207	675	845	131	240	170	7,409
2016/17	8,739	701	8,038	191	695	878	79	243	165	6,489
2017/18	11,559	1071	10,488	244	699	913	79	246	196	9,182
2018/19	8,527	572	7,955	239	711	948	82	251	164	6,132
2019/20	9,725	613	9,112	292	670	982	80	256	177	7,268
2020/21	9,654	679	8,975	319	671	1,006	82	260	175	7,141
2021/22	10,594	1,038	9,556	317	668	1,013	83	261	195	8,056
2022/23	10,474	1,047	9,426	317	638	975	83	262	194	8,005
FORECAST:										
2023/24	11,506	852	10,654	388	646	1,055	87	263	195	8,872
2024/25	11,787	1,052	10,735	388	654	1,081	90	266	196	9,112
2025/26	11,833	1,052	10,781	388	662	1,101	93	268	196	9,124
2026/27	11,908	1,052	10,855	388	670	1,120	96	270	197	9,165
2027/28	11,452	451	11,001	388	671	1,141	100	273	198	8,682
2028/29	11,594	451	11,143	388	672	1,161	103	276	200	8,795
2029/30	11,784	451	11,333	388	673	1,180	106	278	202	8,957
2030/31	11,870	401	11,469	388	674	1,197	109	280	204	9,017
2031/32	12,002	401	11,601	388	675	1,215	112	282	205	9,125
2032/33	12,112	401	11,711	388	676	1,232	115	284	206	9,210

Historical Values (2014 - 2023):

Col. (2) = recorded peak + implemented load control + residential and commercial/industrial conservation and customer-owned self-service cogeneration.

Cols. (5) - (9) = Represent total cumulative capabilities at peak. Col. (8) includes commercial load management and standby generation.

Col. (OTH) = Voltage reduction and customer-owned self-service cogeneration.

Col. (10) = (2) - (5) - (6) - (7) - (8) - (9) - (OTH).

Projected Values (2024 - 2033):

Cols. (2) - (4) = forecasted peak without load control, cumulative conservation, and customer-owned self-service cogeneration.

Cols. (5) - (9) = Represent cumulative conservation and load control capabilities at peak. Col. (8) includes commercial load management and standby generation.

Col. (OTH) = Voltage reduction and customer-owned self-service cogeneration.

Col. (10) = (2) - (5) - (6) - (7) - (8) - (9) - (OTH).

DUKE ENERGY FLORIDA

SCHEDULE 3.2.2

HISTORY AND FORECAST OF WINTER PEAK DEMAND (MW)

HIGH CASE FORECAST

(1) YEAR	(2) TOTAL	(3) WHOLESALE	(4) RETAIL	(5) INTERRUPTIBLE	(6) RESIDENTIAL LOAD MANAGEMENT	(7) RESIDENTIAL CONSERVATION	(8) COMM. / IND. LOAD MANAGEMENT	(9) COMM. / IND. CONSERVATION	(OTH) OTHER DEMAND REDUCTIONS	(10) NET FIRM DEMAND
HISTORY:										
2013/14	9,467	658	8,809	257	654	785	101	229	219	7,222
2014/15	10,648	1,035	9,613	273	658	815	109	236	237	8,319
2015/16	9,678	1,275	8,403	207	675	845	131	240	170	7,409
2016/17	8,739	701	8,038	191	695	878	79	243	165	6,489
2017/18	11,559	1,071	10,488	244	699	913	79	246	196	9,182
2018/19	8,527	572	7,955	239	711	948	82	251	164	6,132
2019/20	9,725	613	9,112	292	670	982	80	256	177	7,268
2020/21	9,654	679	8,975	319	671	1,006	82	260	175	7,141
2021/22	10,594	1,038	9,556	317	668	1,013	83	261	195	8,056
2022/23	10,474	1,047	9,426	317	638	975	83	262	194	8,005
FORECAST:										
2023/24	13,301	852	12,449	388	646	1,055	87	263	195	10,667
2024/25	13,680	1,052	12,628	388	654	1,081	90	266	196	11,005
2025/26	13,779	1,052	12,727	388	662	1,101	93	268	196	11,070
2026/27	13,899	1,052	12,847	388	670	1,120	96	270	197	11,157
2027/28	13,491	451	13,039	388	671	1,141	100	273	198	10,720
2028/29	13,641	451	13,190	388	672	1,161	103	276	200	10,842
2029/30	13,836	451	13,385	388	673	1,180	106	278	202	11,009
2030/31	13,938	401	13,538	388	674	1,197	109	280	204	11,086
2031/32	14,083	401	13,682	388	675	1,215	112	282	205	11,205
2032/33	14,209	401	13,808	388	676	1,232	115	284	206	11,307

Historical Values (2014 - 2023):

Col. (2) = recorded peak + implemented load control + residential and commercial/industrial conservation and customer-owned self-service cogeneration.

Cols. (5) - (9) = Represent total cumulative capabilities at peak. Col. (8) includes commercial load management and standby generation.

Col. (OTH) = Voltage reduction and customer-owned self-service cogeneration.

Col. (10) = (2) - (5) - (6) - (7) - (8) - (9) - (OTH).

Projected Values (2024 - 2033):

Cols. (2) - (4) = forecasted peak without load control, cumulative conservation, and customer-owned self-service cogeneration.

Cols. (5) - (9) = Represent cumulative conservation and load control capabilities at peak. Col. (8) includes commercial load management and standby generation.

Col. (OTH) = Voltage reduction and customer-owned self-service cogeneration.

Col. (10) = (2) - (5) - (6) - (7) - (8) - (9) - (OTH).

DUKE ENERGY FLORIDA

SCHEDULE 3.2.3
HISTORY AND FORECAST OF WINTER PEAK DEMAND (MW)
LOW CASE FORECAST

(1) YEAR	(2) TOTAL	(3) WHOLESALE	(4) RETAIL	(5) INTERRUPTIBLE	(6) RESIDENTIAL LOAD MANAGEMENT	(7) RESIDENTIAL CONSERVATION	(8) COMM. / IND. LOAD MANAGEMENT	(9) COMM. / IND. CONSERVATION	(OTH) OTHER DEMAND REDUCTIONS	(10) NET FIRM DEMAND
HISTORY:										
2013/14	9,467	658	8,809	257	654	785	101	229	219	7,222
2014/15	10,648	1,035	9,613	273	658	815	109	236	237	8,319
2015/16	9,678	1,275	8,403	207	675	845	131	240	170	7,409
2016/17	8,739	701	8,038	191	695	878	79	243	165	6,489
2017/18	11,559	1,071	10,488	244	699	913	79	246	196	9,182
2018/19	8,527	572	7,955	239	711	948	82	251	164	6,132
2019/20	9,725	613	9,112	292	670	982	80	256	177	7,268
2020/21	9,654	679	8,975	319	671	1,006	82	260	175	7,141
2021/22	10,594	1,038	9,556	317	668	1,013	83	261	195	8,056
2022/23	10,474	1,047	9,426	317	638	975	83	262	194	8,005
FORECAST:										
2023/24	9,330	852	8,478	388	646	1,055	87	263	195	6,696
2024/25	9,493	1,052	8,441	388	654	1,081	90	266	196	6,818
2025/26	9,559	1,052	8,507	388	662	1,101	93	268	196	6,850
2026/27	9,655	1,052	8,603	388	670	1,120	96	270	197	6,913
2027/28	9,187	451	8,736	388	671	1,141	100	273	198	6,416
2028/29	9,291	451	8,840	388	672	1,161	103	276	200	6,492
2029/30	9,423	451	8,972	388	673	1,180	106	278	202	6,596
2030/31	9,472	401	9,071	388	674	1,197	109	280	204	6,619
2031/32	9,567	401	9,166	388	675	1,215	112	282	205	6,689
2032/33	9,645	401	9,245	388	676	1,232	115	284	206	6,744

Historical Values (2014 - 2023):

Col. (2) = recorded peak + implemented load control + residential and commercial/industrial conservation and customer-owned self-service cogeneration.

Cols. (5) - (9) = Represent total cumulative capabilities at peak. Col. (8) includes commercial load management and standby generation.

Col. (OTH) = Voltage reduction and customer-owned self-service cogeneration.

Col. (10) = (2) - (5) - (6) - (7) - (8) - (9) - (OTH).

Projected Values (2024 - 2033):

Cols. (2) - (4) = forecasted peak without load control, cumulative conservation, and customer-owned self-service cogeneration.

Cols. (5) - (9) = Represent cumulative conservation and load control capabilities at peak. Col. (8) includes commercial load management and standby generation.

Col. (OTH) = Voltage reduction and customer-owned self-service cogeneration.

Col. (10) = (2) - (5) - (6) - (7) - (8) - (9) - (OTH).

DUKE ENERGY FLORIDA

SCHEDULE 3.3.1

HISTORY AND FORECAST OF ANNUAL NET ENERGY FOR LOAD (GWh)

BASE CASE FORECAST

(1) YEAR	(2) TOTAL	(3) RESIDENTIAL CONSERVATION	(4) COMM. / IND. CONSERVATION	(OTH) OTHER ENERGY REDUCTIONS	(5) RETAIL	(6) WHOLESALE	(7) UTILITY USE & LOSSES	(8) NET ENERGY FOR LOAD	(9) LOAD FACTOR (%) *
HISTORY:									
2014	43,443	812	791	864	37,240	1,333	2,402	40,975	50.7
2015	44,552	848	829	595	38,553	1,243	2,484	42,280	50.9
2016	45,200	892	857	596	38,774	1,803	2,277	42,854	50.6
2017	45,318	933	871	595	38,024	2,196	2,699	42,919	52.7
2018	46,729	977	933	595	39,145	2,304	2,775	44,224	48.9
2019	47,385	1,017	972	595	39,187	2,910	2,704	44,801	51.3
2020	47,476	1,050	1,016	596	39,230	2,887	2,697	44,814	52.9
2021	47,786	1,100	1,027	595	39,451	3,302	2,311	45,064	53.1
2022	48,842	1,120	986	595	40,512	3,673	1,956	46,141	52.8
2023	46,805	1,168	996	595	40,832	1,392	1,821	44,046	49.0
FORECAST:									
2024	46,240	1,223	1,004	595	40,063	1,119	2,237	43,418	55.1
2025	46,392	1,259	1,018	596	40,658	904	1,956	43,519	54.4
2026	46,503	1,297	1,028	595	40,489	904	2,190	43,584	54.5
2027	46,743	1,337	1,036	595	40,777	900	2,098	43,775	54.5
2028	47,519	1,376	1,044	595	41,336	889	2,279	44,504	57.0
2029	48,183	1,413	1,053	596	42,057	887	2,177	45,121	56.5
2030	49,081	1,447	1,062	595	42,832	887	2,258	45,977	56.7
2031	48,970	1,481	1,070	595	43,493	70	2,260	45,824	55.8
2032	49,789	1,515	1,077	595	43,995	71	2,536	46,602	55.4
2033	50,322	1,547	1,085	596	44,815	70	2,209	47,094	54.6

* Load Factors for historical years are calculated using the actual and projected annual peak.

DUKE ENERGY FLORIDA

SCHEDULE 3.3.2

HISTORY AND FORECAST OF ANNUAL NET ENERGY FOR LOAD (GWh)

HIGH CASE FORECAST

(1) YEAR	(2) TOTAL	(3) RESIDENTIAL CONSERVATION	(4) COMM. / IND. CONSERVATION	(OTH) OTHER ENERGY REDUCTIONS	(5) RETAIL	(6) WHOLESALE	(7) UTILITY USE & LOSSES	(8) NET ENERGY FOR LOAD	(9) LOAD FACTOR (%) *
HISTORY:									
2014	43,443	812	791	864	37,240	1,333	2,402	40,975	50.7
2015	44,552	848	829	595	38,553	1,243	2,484	42,280	50.9
2016	45,200	892	857	596	38,774	1,803	2,277	42,854	50.6
2017	45,318	933	871	595	38,024	2,196	2,699	42,919	52.7
2018	46,729	977	933	595	39,145	2,304	2,775	44,224	48.9
2019	47,385	1,017	972	595	39,187	2,910	2,704	44,801	51.3
2020	47,476	1,050	1,016	596	39,230	2,887	2,697	44,814	52.9
2021	47,786	1,100	1,027	595	39,451	3,302	2,311	45,064	53.1
2022	48,842	1,120	986	595	40,512	3,673	1,956	46,141	52.8
2023	46,805	1,168	996	595	40,832	1,392	1,821	44,046	49.0
FORECAST:									
2024	50,309	1,223	1,004	595	43,570	1,119	2,799	47,488	50.8
2025	50,724	1,259	1,018	595	44,363	904	2,584	47,852	49.6
2026	50,998	1,297	1,028	596	44,398	904	2,775	48,077	49.4
2027	51,392	1,337	1,036	595	44,794	900	2,731	48,425	49.5
2028	52,263	1,376	1,044	595	45,465	889	2,894	49,248	52.4
2029	52,876	1,413	1,053	596	46,104	887	2,823	49,814	52.3
2030	53,776	1,447	1,062	595	46,883	887	2,902	50,671	52.5
2031	53,719	1,481	1,070	595	47,580	70	2,922	50,572	52.1
2032	54,562	1,515	1,077	595	48,168	71	3,136	51,375	52.3
2033	55,139	1,547	1,085	596	48,936	70	2,905	51,911	52.3

* Load Factors for historical years are calculated using the actual and projected annual peak.

DUKE ENERGY FLORIDA

SCHEDULE 3.3.3

HISTORY AND FORECAST OF ANNUAL NET ENERGY FOR LOAD (GWh)

LOW CASE FORECAST

(1) YEAR	(2) TOTAL	(3) RESIDENTIAL CONSERVATION	(4) COMM. / IND. CONSERVATION	(OTH) OTHER ENERGY REDUCTIONS	(5) RETAIL	(6) WHOLESALE	(7) UTILITY USE & LOSSES	(8) NET ENERGY FOR LOAD	(9) LOAD FACTOR (%) *
HISTORY:									
2014	43,443	812	791	864	37,240	1,333	2,402	40,975	50.7
2015	44,552	848	829	595	38,553	1,243	2,484	42,280	50.9
2016	45,200	892	857	596	38,774	1,803	2,277	42,854	50.6
2017	45,318	933	871	595	38,024	2,196	2,699	42,919	52.7
2018	46,729	977	933	595	39,145	2,304	2,775	44,224	48.9
2019	47,385	1,017	972	595	39,187	2,910	2,704	44,801	51.3
2020	47,476	1,050	1,016	596	39,230	2,887	2,697	44,814	52.9
2021	47,786	1,100	1,027	595	39,451	3,302	2,311	45,064	53.1
2022	48,842	1,120	986	595	40,512	3,673	1,956	46,141	52.8
2023	46,805	1,168	996	595	40,832	1,392	1,821	44,046	49.0
FORECAST:									
2024	42,916	1,223	1,004	595	37,216	1,119	1,760	40,094	53.5
2025	42,904	1,259	1,018	596	37,615	904	1,512	40,031	54.4
2026	43,227	1,297	1,028	595	37,715	904	1,688	40,308	54.9
2027	43,629	1,337	1,036	595	38,122	900	1,640	40,662	55.2
2028	44,398	1,376	1,044	595	38,712	889	1,782	41,383	55.4
2029	44,918	1,413	1,053	596	39,268	887	1,701	41,856	54.8
2030	45,668	1,447	1,062	595	39,914	887	1,762	42,564	55.1
2031	45,441	1,481	1,070	595	40,454	70	1,770	42,294	52.0
2032	46,116	1,515	1,077	595	40,898	71	1,961	42,929	51.7
2033	46,544	1,547	1,085	596	41,515	70	1,732	43,317	52.9

* Load Factors for historical years are calculated using the actual and projected annual peak.

DUKE ENERGY FLORIDA

SCHEDULE 4.1

PREVIOUS YEAR ACTUAL AND TWO-YEAR FORECAST OF PEAK DEMAND AND NET ENERGY FOR LOAD BY MONTH

BASE CASE FORECAST

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	ACTUAL		FORECAST		FORECAST	
	2023		2024		2025	
MONTH	PEAK DEMAND MW	NEL GWh	PEAK DEMAND MW	NEL GWh	PEAK DEMAND MW	NEL GWh
JANUARY	7,840	3,128	**10,109**	3,205	**10,360**	3,239
FEBRUARY	6,657	2,797	7,984	2,772	8,190	2,784
MARCH	7,608	3,320	7,559	3,170	7,694	3,180
APRIL	7,845	3,457	7,963	3,342	7,685	3,360
MAY	8,354	3,781	8,773	3,832	8,532	3,863
JUNE	9,322	4,188	9,099	4,171	8,769	4,138
JULY	9,725	4,767	9,758	4,345	9,448	4,304
AUGUST	**10,268**	4,978	**9,851**	4,453	**9,696**	4,469
SEPTEMBER	9,281	4,152	8,897	3,988	8,685	4,013
OCTOBER	7,859	3,455	8,492	3,715	8,277	3,723
NOVEMBER	6,799	3,010	6,905	3,111	6,735	3,136
DECEMBER	5,936	3,014	7,965	3,314	8,210	3,310
TOTAL		44,046		43,418		43,519

NOTE: Recorded Net Peak demands and NEL include off-system wholesale contracts.
December 2022 is the 2023 winter peak 8110 MW.

DUKE ENERGY FLORIDA

SCHEDULE 4.2

PREVIOUS YEAR ACTUAL AND TWO-YEAR FORECAST OF PEAK DEMAND
AND NET ENERGY FOR LOAD BY MONTH

HIGH CASE FORECAST

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	ACTUAL		FORECAST		FORECAST	
	2023		2024		2025	
MONTH	PEAK DEMAND MW	NEL GWh	PEAK DEMAND MW	NEL GWh	PEAK DEMAND MW	NEL GWh
JANUARY	7,840	3,128	**11,904**	3,648	**12,253**	3,713
FEBRUARY	6,657	2,797	9,231	3,210	9,507	3,250
MARCH	7,608	3,320	8,617	3,668	8,806	3,702
APRIL	7,845	3,457	8,545	3,668	8,369	3,707
MAY	8,354	3,781	9,276	4,055	9,078	4,107
JUNE	9,322	4,188	9,625	4,394	9,338	4,382
JULY	9,725	4,767	10,277	4,544	10,014	4,524
AUGUST	10,268	4,978	**10,349**	4,643	**10,235**	4,678
SEPTEMBER	9,281	4,152	9,356	4,171	9,180	4,213
OCTOBER	7,859	3,455	9,141	4,049	8,962	4,076
NOVEMBER	6,799	3,010	7,664	3,517	7,569	3,560
DECEMBER	5,936	3,014	9,795	3,921	10,090	3,939
TOTAL		44,046		47,488		47,852

NOTE: Recorded Net Peak demands and NEL include off-system wholesale contracts.
December 2022 is the 2023 winter peak 8110 MW.

SCHEDULE 4.3

PREVIOUS YEAR ACTUAL AND TWO-YEAR FORECAST OF PEAK DEMAND AND NET ENERGY FOR LOAD BY MONTH

LOW CASE FORECAST

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	ACTUAL		FORECAST		FORECAST	
	2023		2024		2025	
MONTH	PEAK DEMAND MW	NEL GWh	PEAK DEMAND MW	NEL GWh	PEAK DEMAND MW	NEL GWh
JANUARY	7,840	3,128	**7,933**	2,860	**8,066**	2,852
FEBRUARY	6,657	2,797	6,902	2,390	7,046	2,374
MARCH	7,608	3,320	6,761	2,809	6,836	2,790
APRIL	7,845	3,457	7,558	3,119	7,239	3,114
MAY	8,354	3,781	8,402	3,673	8,120	3,684
JUNE	9,322	4,188	8,659	3,977	8,315	3,928
JULY	9,725	4,767	9,307	4,162	8,976	4,111
AUGUST	**10,268**	4,978	**9,398**	4,265	**9,233**	4,277
SEPTEMBER	9,281	4,152	8,469	3,799	8,255	3,824
OCTOBER	7,859	3,455	7,973	3,451	7,761	3,461
NOVEMBER	6,799	3,010	6,321	2,776	6,128	2,802
DECEMBER	5,936	3,014	6,423	2,816	6,706	2,812
TOTAL		44,046		40,094		40,031

NOTE: Recorded Net Peak demands and NEL include off-system wholesale contracts.
December 2022 is the 2023 winter peak 8110 MW.

FUEL REQUIREMENTS AND ENERGY SOURCES

DEF's two-year actual and ten-year projected nuclear, coal, oil, and gas requirements (by fuel unit) are shown in Schedule 5. DEF's two-year actual and ten-year projected energy sources by fuel type are presented in Schedules 6.1 and 6.2, in GWh and percent (%) respectively. Although DEF's fuel mix continues to rely on an increasing amount of natural gas to meet its generation needs, DEF continues to maintain alternate fuel supplies including long term operation of some coal fired facilities, adequate supplies of oil for dual fuel back up and increasing amounts of renewable generation particularly from solar generation. Projections shown in Schedules 5 and 6 reflect the Base Load and Energy Forecasts.

DUKE ENERGY FLORIDA

SCHEDULE 5
FUEL REQUIREMENTS

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
				-ACTUAL-											
	FUEL REQUIREMENTS		UNITS	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
(1)	NUCLEAR		TRILLION BTU	0	0	0	0	0	0	0	0	0	0	0	0
(2)	COAL		1,000 TON	2,117	1,825	1,045	927	815	768	702	695	789	814	768	927
(3)	RESIDUAL	TOTAL	1,000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(4)		STEAM	1,000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(5)		CC	1,000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(6)		CT	1,000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(7)		DIESEL	1,000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(8)	DISTILLATE	TOTAL	1,000 BBL	312	124	26	19	16	27	47	36	29	33	36	37
(9)		STEAM	1,000 BBL	48	54	11	9	12	14	10	12	13	9	11	14
(10)		CC	1,000 BBL	123	0	0	0	0	0	0	0	0	0	0	0
(11)		CT	1,000 BBL	141	70	15	10	4	14	37	24	16	24	24	24
(12)		DIESEL	1,000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(13)	NATURAL GAS	TOTAL	1,000 MCF	271,484	265,288	252,983	255,245	253,111	248,403	247,856	244,586	238,530	229,462	228,043	223,608
(14)		STEAM	1,000 MCF	25,066	21,181	15,119	13,755	10,865	8,764	11,038	13,379	10,949	11,540	12,064	11,894
(15)		CC	1,000 MCF	238,711	234,659	233,195	236,804	237,822	234,218	231,497	225,655	222,892	211,949	209,562	204,652
(16)		CT	1,000 MCF	7,708	9,448	4,670	4,686	4,425	5,421	5,321	5,552	4,689	5,973	6,418	7,062
	OTHER (SPECIFY)														
(17)	OTHER, DISTILLATE	ANNUAL FIRM INTERCHANGE	1,000 BBL	N/A	N/A	0	0	0	0	0	0	0	0	0	0
(18)	OTHER, NATURAL GAS	ANNUAL FIRM INTERCHANGE, CC	1,000 MCF	N/A	N/A	0	0	0	0	0	0	0	0	0	0
(18.1)	OTHER, NATURAL GAS	ANNUAL FIRM INTERCHANGE, CT	1,000 MCF	N/A	N/A	2,420	2,650	1,639	601	0	0	0	0	0	0
(19)	OTHER, COAL	ANNUAL FIRM INTERCHANGE, STEAM	1,000 TON	N/A	N/A	0	0	0	0	0	0	0	0	0	0

DUKE ENERGY FLORIDA

SCHEDULE 6.1
ENERGY SOURCES (GWh)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
				-ACTUAL-											
	ENERGY SOURCES		UNITS	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
(1)	ANNUAL FIRM INTERCHANGE 1/		GWh	1,203	60	237	260	161	60	18	3	6	15	7	2
(2)	NUCLEAR		GWh	0	0	0	0	0	0	0	0	0	0	0	0
(3)	COAL		GWh	4,375	3,829	2,157	1,920	1,639	1,539	1,370	1,395	1,569	1,617	1,519	1,873
(4)	RESIDUAL	TOTAL	GWh	0	0	0	0	0	0	0	0	0	0	0	0
(5)		STEAM	GWh	0	0	0	0	0	0	0	0	0	0	0	0
(6)		CC	GWh	0	0	0	0	0	0	0	0	0	0	0	0
(7)		CT	GWh	0	0	0	0	0	0	0	0	0	0	0	0
(8)		DIESEL	GWh	0	0	0	0	0	0	0	0	0	0	0	0
(9)	DISTILLATE	TOTAL	GWh	146	29	7	5	2	6	17	11	7	10	11	10
(10)		STEAM	GWh	0	0	0	0	0	0	0	0	0	0	0	0
(11)		CC	GWh	91	0	0	0	0	0	0	0	0	0	0	0
(12)		CT	GWh	55	29	7	5	2	6	17	11	7	10	11	10
(13)		DIESEL	GWh	0	0	0	0	0	0	0	0	0	0	0	0
(14)	NATURAL GAS	TOTAL	GWh	36,423	35,526	36,389	37,056	37,034	36,479	36,197	35,521	34,714	33,083	32,668	31,801
(15)		STEAM	GWh	2,249	1,737	1,337	1,205	948	749	942	1,137	916	992	1,032	1,004
(16)		CC	GWh	33,607	32,996	34,577	35,374	35,631	35,193	34,722	33,831	33,331	31,509	31,014	30,123
(17)		CT	GWh	567	792	475	477	456	537	533	553	467	582	622	674
(18)	OTHER 2/														
	QF PURCHASES		GWh	1,769	1,814	818	493	0	0	0	0	0	0	0	0
	RENEWABLES OTHER		GWh	0	0	0	0	0	0	0	0	0	0	0	0
	RENEWABLES MSW		GWh	645	624	556	71	73	73	73	73	72	73	73	71
	RENEWABLES BIOMASS		GWh	0	0	0	0	0	0	0	0	0	0	0	0
	RENEWABLES SOLAR		GWh	1,581	2,165	3,255	3,714	4,674	5,630	6,852	8,161	9,670	11,097	12,401	13,415
	BATTERIES		GWh	0	0	0	0	0	-11	-22	-43	-61	-72	-76	-78
	IMPORT FROM OUT OF STATE		GWh	0	0	0	0	0	0	0	0	0	0	0	0
	EXPORT TO OUT OF STATE		GWh	0	0	0	0	0	0	0	0	0	0	0	0
(19)	NET ENERGY FOR LOAD		GWh	46,141	44,046	43,418	43,519	43,584	43,775	44,504	45,121	45,977	45,824	46,602	47,094

1/ NET ENERGY PURCHASED (+) OR SOLD (-) WITHIN THE FRCC REGION.
2/ NET ENERGY PURCHASED (+) OR SOLD (-).

DUKE ENERGY FLORIDA

SCHEDULE 6.2

ENERGY SOURCES (PERCENT)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
				-ACTUAL-											
	ENERGY SOURCES		UNITS	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
(1)	ANNUAL FIRM INTERCHANGE 1/		%	2.6%	0.1%	0.5%	0.6%	0.4%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(2)	NUCLEAR		%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(3)	COAL		%	9.5%	8.7%	5.0%	4.4%	3.8%	3.5%	3.1%	3.1%	3.4%	3.5%	3.3%	4.0%
(4)	RESIDUAL	TOTAL	%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(5)		STEAM	%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(6)		CC	%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(7)		CT	%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(8)		DIESEL	%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(9)	DISTILLATE	TOTAL	%	0.3%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(10)		STEAM	%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(11)		CC	%	0.2%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(12)		CT	%	0.1%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(13)		DIESEL	%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(14)	NATURAL GAS	TOTAL	%	78.9%	80.7%	83.8%	85.1%	85.0%	83.3%	81.3%	78.7%	75.5%	72.2%	70.1%	67.5%
(15)		STEAM	%	4.9%	3.9%	3.1%	2.8%	2.2%	1.7%	2.1%	2.5%	2.0%	2.2%	2.2%	2.1%
(16)		CC	%	72.8%	74.9%	79.6%	81.3%	81.8%	80.4%	78.0%	75.0%	72.5%	68.8%	66.6%	64.0%
(17)		CT	%	1.2%	1.8%	1.1%	1.1%	1.0%	1.2%	1.2%	1.2%	1.0%	1.3%	1.3%	1.4%
(18)	OTHER 2/														
	QF PURCHASES		%	3.8%	4.1%	1.9%	1.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
	RENEWABLES OTHER		%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
	RENEWABLES MSW		%	1.4%	1.4%	1.3%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%
	RENEWABLES BIOMASS		%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
	RENEWABLES SOLAR		%	3.4%	4.9%	7.5%	8.5%	10.7%	12.9%	15.4%	18.1%	21.0%	24.2%	26.6%	28.5%
	BATTERIES		%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	-0.1%	-0.1%	-0.2%	-0.2%	-0.2%
	IMPORT FROM OUT OF STATE		%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
	EXPORT TO OUT OF STATE		%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(19)	NET ENERGY FOR LOAD		%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

1/ NET ENERGY PURCHASED (+) OR SOLD (-) WITHIN THE FRCC REGION.

2/ NET ENERGY PURCHASED (+) OR SOLD (-).

FORECASTING METHODS AND PROCEDURES

INTRODUCTION

Accurate forecasts of long-range electric energy consumption, customer growth, and peak demand are essential elements in electric utility planning. Accurate projections of a utility's future load growth require a forecasting methodology with the ability to account for a variety of factors influencing electric consumption over the planning horizon. DEF's forecasting framework utilizes a set of econometric models as well as the Itron statistically adjusted end-use (SAE) approach to achieve this end. This section will describe the underlying methodology of the customer, energy, and peak demand forecasts including the principal assumptions incorporated within each. Also included is a description of how DSM impacts the forecast and a review of DEF's DSM programs.

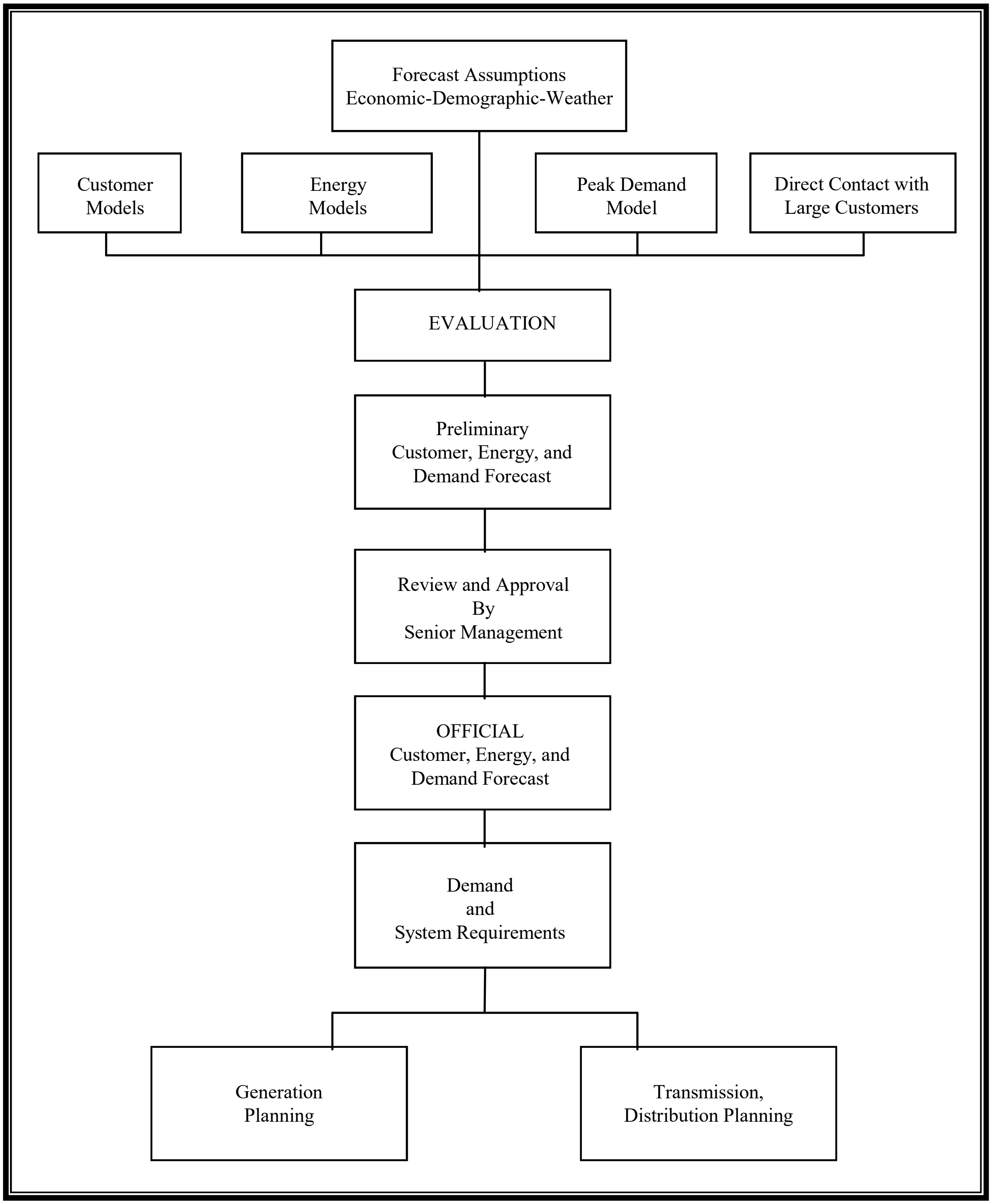
Figure 2.1, entitled "Customer, Energy and Demand Forecast," gives a general description of DEF's forecasting process. Highlighted in the diagram is a disaggregated modeling approach that blends the impacts of average class usage, as well as customer growth, based on a specific set of assumptions for each class. Also accounted for is some direct contact with large customers. These inputs provide the tools needed to frame the most likely scenario of the Company's future demand.

FORECAST ASSUMPTIONS

The first step in any forecasting effort is the development of assumptions upon which the forecast is based. A collaborative internal Company effort develops these assumptions including the research efforts of several external sources. These assumptions specify major factors that influence the level of customers, energy sales, or peak demand over the forecast horizon. The following set of assumptions forms the basis for the forecast presented in this document.

FIGURE 2.1

Customer, Energy, and Demand Forecast



GENERAL ASSUMPTIONS

1. Normal weather conditions for energy sales are assumed over the forecast horizon using a sales-weighted 30-year average of conditions at the St. Petersburg, Orlando, and Tallahassee weather stations. For billed kilowatt-hour (kWh) sales projections, the normal weather calculation begins with a historical 30-year average of calendar and billing cycle weighted monthly heating and cooling degree-days (HDD and CDD). The expected consumption period read dates for each projected billing cycle determines the exact historical dates for developing the 30-year average weather condition each month. Each class displays different weather-sensitive base temperatures from which degree day (DD) values begin to accumulate. Seasonal and monthly peak demand projections are based on a 30-year historical average of system-weighted degree days using the "Itron Rank-Sort Normal" approach which takes annual weather extremes into account as well as the date and hour of occurrence.

2. The DEF customer forecast is based upon Moody's historical and forecasted population estimates of the 29 counties served by DEF. National and Florida economic projections produced by Moody's Analytics in their July 2023 forecast, along with Energy Information Administration (EIA) 2023 surveys of residential appliance saturation and average appliance efficiency levels provided the basis for development of the DEF energy forecast.

3. Within the DEF service area, the phosphate mining industry is the dominant sector in the industrial sales class. Two major customers accounted for approximately 39% of the industrial class MWh sales in 2023. These energy-intensive "crop nutrient" producers mine and process phosphate-based fertilizer products for the global marketplace. The supply and demand (price) for their products are dictated by global conditions that include, but are not limited to, foreign competition, national/international agricultural industry conditions, exchange-rate fluctuations, international trade pacts and U.S. environmental regulations. The market price of the raw mined commodity often dictates production levels. Load and energy consumption at the DEF-served mining or chemical processing sites depend heavily on plant operations, which are heavily influenced by these global as well as the local conditions, including environmental regulations. Going forward, global currency fluctuations and global stockpiles of farm commodities will determine the demand for fertilizers. Any increase in self-service generation will act to reduce energy

requirements from DEF. An upside risk to this projection lies in the price of energy, especially low natural gas price, which is a major cost in mining and producing phosphoric fertilizers. DEF has begun to assume a decline in Phosphate sector energy consumption late in the planning horizon as mining product becomes scarce in the areas currently mined.

4. DEF has supplied capacity and energy service to wholesale customers on a "full" and "partial" requirement basis for many years. Many Sales for Resale Customers have moved to other suppliers for their needs or have begun to self-generate. What remains are Partial Requirements (PR) contracted loads with the Reedy Creek Improvement District (RCID) and Seminole Electric Cooperative, Inc. (SECI). The forecast reflects the current contractual obligations based on the nature of the stratified load being requested, plus their ability to receive dispatched energy from power marketers any time it is more economical for them to do so. All contracts are projected to expire in the specific year designated in the respective contracts.

5. This forecast assumes that DEF will successfully renew all future franchise agreements.

6. This forecast incorporates demand and energy reductions expected to be realized through currently FPSC approved DSM goals as stated in Docket No. 20190018-EG.

7. This forecast reflects impacts from both Plug-in Hybrid Electric Vehicle (PHEV) and behind the meter customer-owned renewable generation which is mostly solar photovoltaic (PV) installations on energy and peak demand. PHEV customer penetration levels, which are expected to be a small share of the total DEF service area vehicle stock over the planning horizon, incorporates an EPRI Model view that includes gasoline price expectations. DEF customer PV penetration levels are expected to continue to grow over the planning horizon and the forecast incorporates a view on equipment and electric price impacts on customer use.

8. Expected energy and demand reductions from customer-owned self-service cogeneration facilities are also included in this forecast. DEF will supply the supplemental load of self-service

cogeneration customers. While DEF offers “standby” service to all cogeneration customers, the forecast does not assume an unplanned need for power at time of peak.

This forecast assumes that the regulatory environment and the obligation to serve our retail customers will continue throughout the forecast horizon. Regarding wholesale customers, the forecast does not plan for generation resources unless a long-term contract is in place.

ECONOMIC ASSUMPTIONS

The economic outlook for this forecast was developed in the summer of 2023.As mentioned in the overview, in mid-2023 the U.S. continued to experience strong job growth, rising wages, and low unemployment. Inflation was receding in response to the Federal Reserve’s rate increases. The funds rate was considered sufficient to slow the economy’s growth and succeed in bringing inflation back to the Fed’s target by the fall of 2024. It is with this background that the DEF Customer, Energy and Peak Demand forecast was developed and the environment in which the Moody’s Analytics July 2023 U.S. forecast and Florida forecast was applied. Major assumptions are as follows:

- In Moody’s July 2023 outlook, an additional 25-basis point rate hike to the federal funds rate was incorporated at the July FOMC meeting. This brought the policy rate’s range to 5.25% to 5.5%. The first-rate cut was also pushed back from March to June 2024. The assumption was that the reduction in the Federal Reserve’s balance sheet would remain on autopilot.

- Recent U.S. bank failures were disconcerting to watch, but they were not symptomatic of a serious broader problem in the financial system. Policymakers’ aggressive response ensured the failures did not weaken the system or more than modestly undermine already-weak economic growth.

- Moody’s did not make any adjustments in light of the Supreme Court striking down President Biden’s student loan forgiveness plan. Moreover, the implications of the ruling for near-term growth were minimal. If the Supreme Court had upheld it, debt cancellation would have only boosted the level of real personal consumption expenditures by 0.1%.

- The ten-year U.S. Treasury peaked in the second quarter of 2024 just shy of 4%, as in the prior baseline.

- Moody's expected strong oil demand growth—headlined by emerging economies and namely China—coupled with OPEC production cuts pushed up oil prices in the second half of the year.

- A full-employment economy is one with an unemployment rate around 3.5%, a 62.5% labor force participation rate, and a prime-age employment-to-population ratio in the range of 80%. The economy was at that level then.

Throughout the ten-year forecast horizon, risks and uncertainties are always recognized and handled on a "highest probability of outcome" basis. General rules of economic theory, namely supply and demand equilibrium, are maintained in the long run. This notion is applied to energy/commodity prices, currency levels, the housing market, wage rates, birth rates, inflation and interest rates. Uncertainty surrounding specific weather anomalies (hurricanes or earthquakes), international crises such as wars or terrorist acts, or future pandemic events, are not explicitly designed into this projection. Thus, any situations of this variety will result in a deviation from this forecast.

FORECAST METHODOLOGY

The DEF forecast of customers, energy sales, and peak demand applies both an econometric and end-use methodology. The residential and commercial energy projections incorporate Itron's SAE approach while other classes use customer-class specific econometric models. These models are expressly designed to capture class-specific variation over time. Peak demand models are projected on a disaggregated basis as well. This allows for appropriate handling of individual assumptions in the areas of wholesale contracts, demand response, interruptible service, and changes in self-service generation capacity.

ENERGY AND CUSTOMER FORECAST

In the retail jurisdiction, customer class models have been specified showing a historical relationship to weather and economic/demographic indicators using monthly data for sales models and customer models. Sales are regressed against "driver" variables that best explain monthly fluctuations over the historical sample period. Forecasts of these input variables are either derived internally or come from a review of the latest projections made by several independent forecasting concerns. Internal company forecasts are used for projections of electricity price, weather conditions, the length of the billing month and rates of customer owned renewable and electric vehicle adoption. The external sources of data include Moody’s Analytics forecasts of changes in population, demographics and economic conditions. The incorporation of residential and commercial “end-use” energy has been modeled as well. Surveys of residential appliance saturation and average efficiency performed by the company’s Market Research department and the EIA, along with trended projections of both by Itron capture a significant piece of the changing future environment for electric energy consumption. Specific sectors are modeled as follows:

Residential Sector

Residential kWh usage per customer is modeled using the SAE framework. This approach explicitly introduces trends in appliance saturation and efficiency, dwelling size and thermal efficiency. It allows for an explanation of usage levels and changes in weather-sensitivity over time. The “bundling” of 19 residential appliances into “heating”, “cooling” and “other” end uses form the basis of equipment-oriented drivers that interact with typical exogenous factors such as real median household income, average household size, cooling degree-days, heating degree-days, the real price of electricity to the residential class and the average number of billing days in each sales month. This structure captures significant variation in residential usage caused by changing appliance efficiency and saturation levels, economic cycles, weather fluctuations, electric price, and sales month duration. Projections of kWh usage per customer combined with the customer forecast provide the forecast of total residential energy sales. The residential customer forecast is developed by correlating monthly residential customers with county level population projections, provided by Moody’s, for counties in which DEF serves residential customers.

Commercial Sector

Commercial MWh energy sales are forecast based on commercial sector (non-agricultural, non-manufacturing and non-governmental) employment, the real price of electricity to the commercial class, the average number of billing days in each sales month, and the heating and cooling degree-day values. As in the residential sector, these variables interact with the commercial end-use equipment (listed below) after trends in equipment efficiency and saturation rates have been projected.

- Heating
- Cooling
- Ventilation
- Water heating
- Cooking
- Refrigeration
- Outdoor Lighting
- Indoor Lighting
- Office Equipment (PCs)
- Miscellaneous

The SAE model contains indices that are based on end-use energy intensity projections developed from EIA's commercial end-use forecast database. Commercial energy intensity is measured in terms of end-use energy use per square foot. End-use energy intensity projections are based on end-use efficiency and saturation estimates that are in turn driven by assumptions in available technology and costs, energy prices, and economic conditions. Energy intensities are calculated from the EIA's Annual Energy Outlook (AEO) commercial database. End-use intensity projections are derived for eleven building types. The energy intensity (EI) is derived by dividing end-use electricity consumption projections by square footage:

$$EI_{bet} = Energy_{bet} / sqft_{bt}$$

Where:

$Energy_{bet}$ = energy consumption for building type b, end-use e, year t

$Sqft_{bt}$ = square footage for building type b in year t

Commercial customers are modeled using the projected level of residential customers.

Industrial Sector

Energy sales to this sector are separated into two sub-sectors. A large portion of industrial energy use is consumed by the phosphate mining industry. Because this one industry is such a large share of the total industrial class, it is separated and modeled apart from the rest of the class. The term "non-phosphate industrial" is used to refer to those customers who comprise the remaining portion of total industrial class sales. Both groups are impacted by changes in economic activity. However, adequately explaining sales levels requires separate explanatory variables. Non-phosphate industrial energy sales are modeled using Florida manufacturing employment, energy prices, and the average number of sales month billing days.

The industrial phosphate mining industry is modeled using customer-specific information with respect to anticipated market conditions. Since this sub-sector is comprised of only three customers, the forecast is dependent upon information received from direct customer contact. DEF Large Account Management employees provide specific phosphate customer information regarding customer production schedules, inventory levels, area mine-out and start-up predictions, and changes in self-service generation or energy supply situations over the forecast horizon. These Florida mining companies compete globally into a global market where farming conditions dictate the need for "crop nutrients".

The projection of industrial accounts was not expected to decline as rapidly as it has in the previous ten years. The pace of "off-shoring" manufacturing jobs was expected to decline from past levels. Both the Trump and Biden administrations have favored the rebuilding of the American manufacturing sector, with the Biden administration adding a focus on carbon reduction. Also, the rapid increase in Florida population may recalibrate Florida's competitiveness in "location analysis" studies performed by industry when determining site selection for new operations.

Street Lighting

Electricity sales to the street and highway lighting class are projected to decrease over the forecast period due to increased energy efficiency. The number of accounts has increased due to rate changes from the Public Authority class. A simple time-trend was used to project energy consumption and customer growth in this class.

Public Authorities

Energy sales to public authorities (SPA), comprised of federal, state and local government operated services, are projected to increase within the DEF's service area. This is a result of a growing economy and population representing a larger tax base. The level of government services, and thus energy, can be tied to the population base, as well as the amount of tax revenue collected to pay for these services. Factors affecting population growth will affect the need for additional governmental services (i.e., public schools, city services, etc.) thereby increasing SPA energy consumption. Government employment has been determined to be the best indicator of the level of government services provided. This variable, along with cooling degree-days, energy prices and the sales month billing days, explains most of the variation over the historical sample period. Adjustments are also included in this model to account for the large change in school-related energy use throughout the year. The SPA customer forecast is projected linearly as a function of a time-trend. Recent budget issues have also had an impact on the near-term pace of growth.

Sales for Resale Sector

The Sales for Resale sector encompasses all firm sales to other electric power entities. This includes sales to other utilities (municipal or investor-owned) as well as power agencies (rural electric authority or municipal).

SECI is a wholesale, or Sales for Resale, customer of DEF that contracts for both seasonal and stratified loads over the forecast horizon. The municipal Sales for Resale class includes a number of customers, divergent not only in scope of service (i.e., full or partial requirement), but also in composition of ultimate consumers. Each customer is modeled separately in order to accurately reflect its individual profile. DEF serves partial requirement service (PR) to load serving customers such as Reedy Creek Improvement District. In each case, these customers contract with DEF for a specific level and type of stratified capacity (MW) needed to provide their particular electrical system with an appropriate level of reliability. The energy forecast for each contract is derived using information provided by the purchaser who better understands their needs. Electric energy growth and competitive market prices will dictate the amount of wholesale demand and energy throughout the forecast horizon.

PEAK DEMAND FORECAST

The forecast of peak demand also employs a disaggregated econometric methodology. For seasonal (winter and summer) peak demands, as well as each month of the year, DEF's coincident system peak is separated into five major components. These components consist of total retail load, interruptible and curtailable tariff non-firm load, conservation and demand response program capability, wholesale demand, and company use demand.

Total retail load refers to projections of DEF retail monthly net peak demand before any activation of DEF's General Load Reduction Plan. The historical values of this series are constructed to show the size of DEF's retail net peak demand assuming no utility activated load control had ever taken place. The value of constructing such a "clean" series enables the forecaster to observe and correlate the underlying trend in retail peak demand to retail customer levels and coincident weather conditions at the time of the peak and the amounts of Base-Heating-Cooling load estimated by the monthly Itron models without the impacts of year-to-year variation in utility-sponsored DR programs. Monthly peaks are projected using the Itron SAE generated use patterns for both weather sensitive (cooling & heating) appliances and base load appliances calculated by class in the energy models. Daily and hourly models of applying DEF class-of-business load research survey data lead to class and total retail hourly load profiles when a 30-year normal weather template replaces actual weather. The projections of retail peak are the result of a monthly model driven by the summation of class base, heating and cooling energy interpolated 30-year normal weather pattern-driven load profile. The projection for the months of January (winter) and August (summer) are typically when the seasonal peaks occur. Energy conservation and direct load control estimates consistent with DEF's DSM goals that have been established by the FPSC are applied to the MW forecast. Projections of dispatchable and cumulative non-dispatchable DSM impacts are subtracted from the projection of potential firm retail demand resulting in a projected series of firm retail monthly peak demand figures. The Interruptible and Curtailable service (IS and CS) tariff load projection is developed from historic monthly trends, as well as the incorporation of specific projected information obtained from DEF's large industrial accounts on these tariffs by account executives. Developing this piece of the demand forecast allows for appropriate firm retail demand results in the total retail coincident peak demand projection.

Sales for Resale demand projections represent load supplied by DEF to other electric suppliers such as SECI, RCID, and other electric transmission and distribution entities. For Partial Requirement demand projections, contracted MW levels dictate the level of seasonal demands.

DEF "company use" at the time of system peak is estimated using load research metering studies similar to potential firm retail. It is assumed to remain stable over the forecast horizon as it has historically.

Each of the peak demand components described above is a positive value except for the DSM program MW impacts and IS and CS load. These impacts represent a reduction in peak demand and are assigned a negative value. Total system firm peak demand is then calculated as the arithmetic sum of the five components.

HIGH AND LOW SCENARIOS

DEF has developed high and low scenarios around the base case energy sales and peak demand projections. Both scenarios incorporate historical variation in weather and economic conditions as well as service area population and household growth. Historical variation for economic driver variables selected in the base case energy sales models using the Moody's S1 & S3 (High/Low) scenarios. High and low weather variables were determined for the energy and peak weather variables (HDDs, CDDs, and monthly peak DDs) using actual 30-year weather conditions. Each weather variable used in the modeling process is ranked monthly from "high-to-low" degree days. The high (hottest or coldest) one-fourth of each variable is averaged and becomes a normal "High Case" weather condition. Similarly, the "mildest" one-fourth of each weather variable's 30 observations are averaged and become the normal "Low Case" weather condition. A review of twenty-year historical variation of DEF 29-county population growth based on Moody's high and low customer projections out ten years resulted in the final area of variability around the Load Forecast.

This procedure captures the most influential variables around energy sales and peak demand by estimating high and low cases for economics, demographics, and weather conditions. DEF has evaluated the load projections generated through this process against projected loads based on extreme temperature events over the last 40 years and concluded that the range of load represented in these cases encompasses the probable outcome of such extreme weather recurrence.

DEMAND SIDE MANAGEMENT

Pursuant to the provisions of Florida Statutes Section 366.82 (the "FEECA Statute"), which requires the FPSC to adopt goals for the FEECA utilities to increase energy efficiency and increase the development of demand-side renewable energy systems and directs the FPSC to review those goals every five years, in 2019, the FPSC conducted its statutorily required review and determined that it was in the public interest to continue with the goals for the 2020-2024 time period established in the 2014 Goals setting proceeding and directed the utilities to file Program Plans designed to achieve these goals (Order No. PSC-2019-0509-FOF-EG). In February 2020, DEF submitted a Plan designed to achieve the 2020-2024 goals which was approved by the Commission (Order No. PSC-2020-0274-PAA-EG) in August of that year. The programs included in this Plan are subject to periodic monitoring and evaluation to ensure that all demand-side resources are acquired in a cost-effective manner and that the program savings are durable. Tables 2.1 and 2.2 reflect the annual Program achievements for the residential and commercial sector compared to the Commission established goals for the 2020-2024 time period.

RESIDENTIAL DEMAND SIDE MANAGEMENT PROGRAMS

TABLE 2.1
Residential DSM MW and GWH Savings

RESIDENTIAL									
	WINTER PEAK MW REDUCTION			SUMMER PEAK MW REDUCTION			GWH ENERGY REDUCTION		
YEAR	TOTAL ACHIEVED	COMMISSION APPROVED GOAL	% VARIANCE	TOTAL ACHIEVED	COMMISSION APPROVED GOAL	% VARIANCE	TOTAL ACHIEVED	COMMISSION APPROVED GOAL	% VARIANCE
2020	31	32	-5%	18	16	13%	35	9	277%
2021	16	28	-42%	10	14	-26%	25	6	311%
2022	25	25	1%	16	12	30%	49	4	1205%
2023	30	22	36%	19	11	70%	50	2	2244%
2024		21			11			1	

The following provides a list of DEF's Residential DSM programs as of December 31, 2023, along with a brief overview of each program:

Home Energy Check – This is DEF's home energy audit program as required by Rule 25-17.003(3)(b), F.A.C. DEF offers a variety of options to customers for home energy audits including walk-through audits, phone assisted audits, and on-line audits. At the completion of the audit, DEF also provides kits that contain energy saving measures that may be easily installed by the customer.

Residential Incentive Program – This program provides incentives on a variety of cost-effective measures designed to provide energy savings. DEF expects to provide incentives to customers for the installation of approximately 75,000 energy saving measures over the 2020 to 2024 time period. These measures primarily include heating and cooling, duct repair, insulation, and energy efficient windows and home energy management systems. The measures and incentive levels included in this program have been updated to reflect the impacts of new codes and standards.

Neighborhood Energy Saver – This program is designed to provide energy saving education and assistance to low-income customers. This program targets neighborhoods that meet certain income eligibility requirements. DEF plans to install energy saving measures in approximately 5,250 homes annually over the 2020 to 2024 time period. Additionally, DEF increased its targeted homes by 5% or 250 homes above the annual projected homes for the calendar years 2022-2024. These measures will be installed at no cost to the customer and include air infiltration measures, water heating measures, lighting, insulation, duct repair, and heat pump and air conditioning tune-ups.

Low Income Weatherization Assistance Program – DEF partners with local agencies to provide funding for energy efficiency and weatherization measures to low-income customers through this program. DEF expects to provide assistance to approximately 500 customers annually through this program.

Residential Load Management a/k/a EnergyWise – This is a voluntary residential demand response program that provides monthly bill credits to customers who allow DEF to reduce peak demand by controlling service to selected electric equipment through various devices and communication options installed on the customer's premises. These interruptions are at DEF's option, during specified time periods, and coincident with hours of peak demand. Customers must have a minimum average monthly usage of 600 kWh to be eligible to participate in this program.

The Company is actively replacing 3G load control devices at customer premises and it remains on track for that work to be completed in 2025, as noted in the 2023 Ten-Year Site Plan. DEF will file its plan for incremental capability in the DSM goal setting docket this year and reflect the Commission approved increases in the 2025 Ten-Year Site Plan.

COMMERCIAL/INDUSTRIAL DEMAND SIDE MANAGEMENT PROGRAMS

TABLE 2.2

Commercial/Industrial DSM MW and GWH Savings

COMMERCIAL / INDUSTRIAL									
	WINTER PEAK MW REDUCTION			SUMMER PEAK MW REDUCTION			GWH ENERGY REDUCTION		
YEAR	TOTAL ACHIEVED	COMMISSION APPROVED GOAL	% VARIANCE	TOTAL ACHIEVED	COMMISSION APPROVED GOAL	% VARIANCE	TOTAL ACHIEVED	COMMISSION APPROVED GOAL	% VARIANCE
2020	24	5	354%	46	8	460%	40	6	582%
2021	11	5	124%	24	7	248%	22	4	454%
2022	5	5	1%	5	6	-17%	3	2	25%
2023	30	5	510%	27	6	377%	10	1	654%
2024		5			5			1	

The following provides a list of DEF's Commercial DSM programs as of December 31, 2023, along with a brief overview of each program:

Business Energy Check – This is a commercial energy audit program that provides commercial customers with an analysis of their energy usage and information about energy-saving practices specific to their business and operations and cost-effective measures that they can implement at their facilities.

Smart $aver Business f/k/a Better Business – This program provides incentives to commercial customers on a variety of cost-effective energy efficiency measures. These measures are primarily comprised of measures that reduce cooling and heating load.

Smart $aver Custom Incentive f/k/a Florida Custom Incentive – The objective of this program is to encourage customers to make capital investments for the installation of energy efficiency measures which reduce energy and peak demand. This program provides incentives for customized energy efficiency projects and measures that are cost effective but are not otherwise included in DEF's prescriptive commercial programs.

Interruptible Service – This program is available to commercial customers with a minimum billing demand of 500 KW or more who are willing to have their power interrupted at times of capacity shortage during peak or emergency conditions. DEF has remote control access to the switch providing power to the customer's equipment. Customers participating in the Interruptible Service program receive a monthly interruptible demand credit based on their bills.

Curtailable Service - This program is an indirect load control program that reduces DEF's energy demand at times of capacity shortage during peak or emergency conditions. The program is available to commercial customers with a minimum of 500KW or more who are willing to curtail their load.

Standby Generation - This program is a demand control program that reduces DEF's demand based upon the control of the customer's back-up generator. The program is a voluntary program available to all commercial and industrial customers who have on-site stand-by generation capacity of at least 50 KW and are willing to allow remote activation of their on-site generation capability in emergencies.

OTHER DSM PROGRAMS

The following provides an overview of other DSM programs:

Technology Development – This program is used to fund research, testing and development of new energy efficiency and demand response technologies. This program provides the opportunity to investigate and test new technologies and determine their usefulness and feasibility in the support of energy efficiency and demand response programs.

Qualifying Facilities – This program analyzes, forecasts, facilitates, and administers the potential and actual power purchases from Qualifying Facilities (QFs) and the state jurisdictional QF or distributed generator interconnections. The program supports meetings with interested parties or potential QFs, including cogeneration and small power production facilities including renewables interested in providing renewable capacity or energy deliveries within our service territory. Project, interconnection, and avoided cost discussions with renewable and combined heat and power developers who are also exploring distributed generation options continue to remain steady. Most of the interest is coming from companies utilizing solar photovoltaic technology as the price of photovoltaic panels has decreased over time. The cost of this technology continues to decrease, and subsidies remain in place. As of December 31st, 2023, DEF had 69 active solar projects totaling approximately 5,100 MW in its FERC jurisdictional interconnection queue and 19 of those projects included DEF as the project developer. As the technologies advance and the market evolves, the Company's policies will continue to be refined and remain compliant.

CHAPTER 3

FORECAST OF FACILITIES REQUIREMENTS

CHAPTER 3

FORECAST OF FACILITIES REQUIREMENTS

RESOURCE PLANNING FORECAST

OVERVIEW OF CURRENT FORECAST

Supply-Side Resources

As of December 31, 2023, DEF had a summer total firm capacity resource of 11,750 MW (see Table 3.1). This capacity resource includes fossil steam generators (2,423 MW), combined cycle plants (5,247 MW), combustion turbines (1,972 MW), solar power plants (648 MW), independent power purchases (1,163 MW), and non-utility purchased power (297 MW). Table 3.2 presents DEF's firm capacity contracts with renewable and cogeneration Facilities.

Demand-Side Programs

In August 2020, the FPSC approved demand-side management programs designed to meet the DSM goals established by the Commission in Order PSC-2019-0509-FOF-EG. Total DSM resources are presented in Schedules 3.1 and 3.2 of Chapter 2. These programs include Non-Dispatchable DSM, Interruptible Load, and Dispatchable Load Control resources.

Capacity and Demand Forecast

DEF's forecasts of capacity and demand for the projected summer and winter peaks can been found in Schedules 7.1 and 7.2, respectively. Demand forecasts shown in these schedules are based on Schedules 3.1.1 and 3.2.1, the base summer and winter forecasts. DEF's forecasts of capacity and demand are based on serving expected growth in retail requirements in its regulated service area and meeting commitments to wholesale power customers who have entered into supply contracts with DEF. In its planning process, DEF balances its supply plan for the needs of retail and wholesale customers and endeavors to ensure that cost-effective resources are available to meet the needs across the customer base.

Base Expansion Plan

DEF's planned supply resource additions and changes are shown in Schedule 8 and are referred to as DEF's Base Expansion Plan. This plan includes a net addition of over 4,700 MW of solar PV generation with an expected equivalent summer firm capacity contribution of approximately 880 MW, 90 MW of firm storage added in 2027 and 430 MW of combustion turbine firm capacity added in years 2032 and 2033. The incorporation of the full firm capacity of the Osprey Energy Center takes place at the end of 2025. Between 2022 and 2027, DEF will add close to 400 MW of combined cycle capacity that results from projects focusing on increasing the fuel efficiency of the combined cycle generating units. DEF continues to consider market supply-side resource alternatives to enhance DEF's resource plan.

DEF recognizes that as solar penetration increases, including both DEF and customer owned PV, the relationship between the solar production and the coincident load peak will change. In this plan, DEF has assigned this DEF owned solar PV generation an equivalent summer capacity value equal to 57% of the nameplate capacity of the planned installations from 2021 to 2024. DEF modeling derives an equivalent summer non-coincident, but on-peak-hour capacity value equal to 25% of the facility's nameplate rating for planned PV installations from 2025 to 2027 and 10% for 2028 and beyond. An annual performance degradation factor of 0.5% has been assigned to the PV installations. DEF will continue to evaluate these assignments over time and may revise these values in future Site Plans based on changes in project designs and the data received from actual operation of these facilities once they are installed. In addition, DEF recognizes that higher penetration of PV resources on the system will result in a need for additional balancing of generation intermittency. The declining capacity value for PV installations late in this decade and beyond could be improved substantially if battery technology advances support economic pairing of PV with energy storage, which could also help to address the need for balancing generation intermittency. DEF's strategy of steady and carefully paced additions of PV to the system will allow continued evaluation of these impacts and the need for additional resources in the future to meet these needs.

In their ongoing efforts to regulate greenhouse gas emissions, on June 19, 2019 the Environmental Protection Agency (EPA) issued the Affordable Clean Energy (ACE) Rule to replace the 2015 Clean Power Plan. However, on January 19, 2021, the U.S. Court of Appeals for the District of

Columbia issued its opinion vacating the ACE Rule and remanding the rule to the EPA. On October 29, 2021, the Supreme Court agreed to hear the appeal of the ACE vacatur. The case was heard at the Supreme Court in February 2022, and on June 30, 2022, the Court issued a decision reversing and remanding the January 19, 2021 D.C. Circuit Court decision. Currently, neither the CPP nor the ACE rule are in effect, as the EPA is working on a replacement rule. On May 23, 2023, EPA proposed five separate actions, which include establishing GHG performance standards for fossil fuel fired EGUs and combustion turbines as well as repealing the ACE rule. The EPA proposal aims to implement more protective GHG emission standards, which are potentially applicable to several DEF coal and natural gas combustion turbine units. DEF will continue to monitor the proposed rule, which is expected to be finalized by May 2024, and the potentially applicable requirements to the DEF emission units.

Duke Energy has set a goal at the enterprise level of achieving at least a 50% reduction in CO_2 emissions from a 2005 baseline by 2030 and net-zero emissions by 2050. DEF has incorporated anticipated tax savings from the 2022 IRA into our resource plan optimization and production cost models. These savings have increased the cost effectiveness of clean energy resources, particularly solar and batteries, enabling further cost-effective progress toward achievement of Duke Energy's enterprise level target.

DEF continues to modernize its generation resources with the retirement and projected retirements of several of the older units in the fleet, particularly combustion turbines at Bayboro, DeBary P2 - P6, and Bartow P1 & P3. Continued operations of the peaking units at Bayboro are planned through the year 2026. The DeBary units P2 - P6 and Bartow units P1 & P3 are projected to retire in 2027. There are many factors which may impact these retirements including environmental regulations and permitting, unit age and maintenance requirements, local operational needs, their relatively small capacity size and system requirement needs. In addition to retirements, DEF anticipates the expiration of several contracts with Qualifying Facilities (QFs) and Independent Power Producers (IPPs) over the plan period. Although the Base Expansion Plan projects expiration of all these contracts, DEF continues to consider options for renewing these contracts in a manner that provides system reliability and cost-effective capacity and energy for our customers.

DEF continues to improve the performance of its generation fleet. Starting in mid-2023 and through the end of 2027, DEF will perform upgrades to the combustion turbines associated with several of the fleet combined cycle units. The goal of these upgrades is to reduce the unit heat rates, improve the fleet fuel efficiency, and reduce DEF CO_2 emissions. These upgrades will also result in the addition of close to 400 MWs of combined cycle capacity.

DEF's Base Expansion Plan projects the need for additional capacity with proposed in-service dates during the ten-year period from 2024 through 2033. The planned capacity additions, together with purchases from QFs, Investor-Owned Utilities (IOUs), and IPPs enable the DEF system to meet the energy requirements of its customer base. The capacity needs identified in this plan may be impacted by DEF's ability to extend or replace existing purchase power, cogeneration and QF contracts and to secure new renewable purchased power resources in their respective projected timeframes. The additions in the Base Expansion Plan depend, in part, on projected load growth, and obtaining all necessary state and federal permits under current schedules. Changes in these or other factors could impact DEF's Base Expansion Plan.

DEF has examined the high and low load scenarios presented in Schedules 3.1 and 3.2. As discussed in Chapter 2, these scenarios were developed to present and test a range of likely outcomes in peak load and energy demand. DEF found that the Base Expansion Plan was robust under the range of conditions examined. Current planned capacity is sufficient to meet the demand including reserve margin in these cases through 2028 allowing DEF sufficient time to plan additional generation capacity either through power purchase or new generation construction as needed if higher than baseline conditions emerge. If lower than baseline conditions emerge, DEF can defer future generation additions.

Status reports and specifications for the planned new generation facilities are included in Schedule 9. Planned transmission lines associated with the DEF Bulk Electric System (BES) are shown in Schedule 10.

TABLE 3.1

DUKE ENERGY FLORIDA

TOTAL CAPACITY RESOURCES OF
POWER PLANTS AND PURCHASED POWER CONTRACTS

AS OF DECEMBER 31, 2023

PLANTS	SUMMER NET DEPENDABLE CAPABILITY (MW)
Fossil Steam	2,423
Combined Cycle	5,247
Combustion Turbine	1,972
Solar	648
Total Net Dependable Generating Capability	**10,290**
Dependable Purchased Power	1,460
Firm Qualifying Facility Contracts (297 MW)	
Investor Owned Utilities (0 MW)	
Independent Power Producers (1,163 MW)	
TOTAL DEPENDABLE CAPACITY RESOURCES	**11,750**

TABLE 3.2

**DUKE ENERGY FLORIDA
FIRM RENEWABLES
AND COGENERATION CONTRACTS**

AS OF DECEMBER 31, 2023

Facility Name	Firm Capacity (MW)
Mulberry	115
Orange Cogen (CFR-Biogen)	104
Pasco County Resource Recovery	23
Pinellas County Resource Recovery	54.8
TOTAL	**296.8**

DUKE ENERGY FLORIDA

SCHEDULE 7.1

FORECAST OF CAPACITY, DEMAND AND SCHEDULED MAINTENANCE
AT TIME OF SUMMER PEAK

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
	TOTAL INSTALLED CAPACITY	FIRM[a] CAPACITY IMPORT	FIRM CAPACITY EXPORT	QF[b]	TOTAL CAPACITY AVAILABLE	SYSTEM FIRM SUMMER PEAK DEMAND	RESERVE MARGIN BEFORE MAINTENANCE		SCHEDULED MAINTENANCE	RESERVE MARGIN AFTER MAINTENANCE	
YEAR	MW	MW	MW	MW	MW	MW	MW	% OF PEAK	MW	MW	% OF PEAK
2024	10,418	874	0	78	11,369	9,000	2,369	26%	0	2,369	26%
2025	10,681	759	0	0	11,440	8,836	2,603	29%	0	2,603	29%
2026	11,319	655	0	0	11,974	8,790	3,184	36%	0	3,184	36%
2027	11,038	0	0	0	11,038	8,781	2,257	26%	0	2,257	26%
2028	11,155	0	0	0	11,155	8,908	2,247	25%	0	2,247	25%
2029	11,242	0	0	0	11,242	9,093	2,149	24%	0	2,149	24%
2030	11,336	0	0	0	11,336	9,260	2,076	22%	0	2,076	22%
2031	11,390	0	0	0	11,390	9,374	2,016	22%	0	2,016	22%
2032	11,873	0	0	0	11,873	9,595	2,279	24%	0	2,279	24%
2033	12,356	0	0	0	12,356	9,811	2,545	26%	0	2,545	26%

Notes:

a. FIRM Capacity Import includes Cogeneration, Utility and Independent Power Producers, and Short Term Purchase Contracts.

b. QF includes Firm Renewables

DUKE ENERGY FLORIDA

SCHEDULE 7.2

FORECAST OF CAPACITY, DEMAND AND SCHEDULED MAINTENANCE
AT TIME OF WINTER PEAK

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
	TOTAL INSTALLED CAPACITY	FIRM[a] CAPACITY IMPORT	FIRM CAPACITY EXPORT	QF[b]	TOTAL CAPACITY AVAILABLE	SYSTEM FIRM WINTER PEAK DEMAND	RESERVE MARGIN BEFORE MAINTENANCE		SCHEDULED MAINTENANCE	RESERVE MARGIN AFTER MAINTENANCE	
YEAR	MW	MW	MW	MW	MW	MW	MW	% OF PEAK	MW	MW	% OF PEAK
2023/24	10,675	1,442	0	78	12,195	8,872	3,323	37%	0	3,323	37%
2024/25	10,774	803	0	0	11,577	9,112	2,465	27%	0	2,465	27%
2025/26	11,272	699	0	0	11,971	9,124	2,847	31%	0	2,847	31%
2026/27	11,205	699	0	0	11,904	9,165	2,739	30%	0	2,739	30%
2027/28	10,902	0	0	0	10,902	8,682	2,220	26%	0	2,220	26%
2028/29	10,974	0	0	0	10,974	8,795	2,179	25%	0	2,179	25%
2029/30	11,046	0	0	0	11,046	8,957	2,089	23%	0	2,089	23%
2030/31	11,118	0	0	0	11,118	9,017	2,100	23%	0	2,100	23%
2031/32	11,118	0	0	0	11,118	9,125	1,993	22%	0	1,993	22%
2032/33	11,587	0	0	0	11,587	9,210	2,377	26%	0	2,377	26%

Notes:

a. FIRM Capacity Import includes Cogeneration, Utility and Independent Power Producers, and Short Term Purchase Contracts.

b. QF includes Firm Renewables

DUKE ENERGY FLORIDA

SCHEDULE 8

PLANNED AND PROSPECTIVE GENERATING FACILITY ADDITIONS AND CHANGES

AS OF JANUARY 1, 2024 THROUGH DECEMBER 31, 2033

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
												FIRM			
								CONST.	COM'L IN-	EXPECTED	GEN. MAX.	NET CAPABILITY			
	UNIT	LOCATION	UNIT	FUEL		FUEL TRANSPORT		START	SERVICE	RETIREMENT	NAMEPLATE	SUMMER	WINTER		
PLANT NAME	NO.	(COUNTY)	TYPE	PRI.	ALT.	PRI.	ALT.	MO. / YR	MO. / YR	MO. / YR	KW	MW	MW	STATUS[a]	NOTES[b]
MULE CREEK	1	BAY	PV	SO				04/2023	03/2024		74,900	43	0	P	(1)
WINQUEPIN	1	MADISON	PV	SO				04/2023	03/2024		74,900	43	0	P	(1)
FALMOUTH	1	SUWANNEE	PV	SO				06/2023	08/2024		74,900	43	0	P	(1)
COUNTY LINE	1	GILCHRIST	PV	SO				12/2023	10/2024		74,900	43	0		(1)
P L BARTOW	4	PINELLAS	CC	NG	DFO	PL	TK	09/2024	11/2024			141	99	P	(1) and (5)
SOLAR DEGRADATION	N/A	N/A	N/A	N/A		N/A		N/A	N/A	N/A	N/A	(3)			(2)
SUNDANCE	1	MADISON	PV	SO				04/2024	03/2025		74,900	19	0		(1)
HINES	2	POLK	CC	NG	DFO	PL	TK	03/2025	05/2025			65	65	P	(1) and (5)
OSPREY CC	1	POLK	CC	NG	DFO	PL	TK		10/2025			347	381	P	(3)
HINES	4	POLK	CC	NG	DFO	PL	TK	10/2025	11/2025			52	52	P	(1) and (5)
BAILEY MILL	1	JEFFERSON	PV	SO				04/2025	12/2025		74,900	19	0		(1)
HALF MOON	1	SUMTER	PV	SO				04/2025	12/2025		74,900	19	0		(1)
RATTLER	1	HERNANDO	PV	SO				04/2025	12/2025		74,900	19	0		(1)
SOLAR DEGRADATION	N/A	N/A	N/A	N/A		N/A		N/A	N/A	N/A	N/A	(4)			(2)
TIGER BAY	1	POLK	CC	NG	DFO	PL	TK	02/2026	03/2026			22	22	P	(1) and (5)
HINES	3	POLK	CC	NG	DFO	PL	TK	02/2026	04/2026			65	65	P	(1) and (5)
CITRUS	PB1	CITRUS	CC	NG				02/2026	05/2026			22	22	P	(1) and (5)
CITRUS	PB2	CITRUS	CC	NG				02/2026	05/2026			22	22	P	(1) and (5)
UNKNOWN		UNKNOWN	PV	SO				09/2025	06/2026		224,700	56			(1) and (4)
UNKNOWN		UNKNOWN	PV	SO				03/2026	12/2026		149,800	37	0	P	(1) and (4)
BAYBORO	P1 - P4	PINELLAS	CT	DFO		WA				10/2026		(151)	(198)		
SOLAR DEGRADATION	N/A	N/A	N/A	N/A		N/A		N/A	N/A	N/A	N/A	(4)			(2)
UNKNOWN		UNKNOWN	BA	N/A		N/A		01/2026	01/2027		100,000	90	90	P	(1)
DEBARY	P2 - P6	VOLUSIA	CT	DFO		TK				06/2027		(227)	(292)		
BARTOW	P1, P3	PINELLAS	CT	DFO		WA				06/2027		(82)	(101)		
UNKNOWN		UNKNOWN	PV	SO				09/2026	06/2027		224,700	56			(1) and (4)
UNKNOWN		UNKNOWN	PV	SO				04/2027	12/2027		149,800	37	0	P	(1) and (4)
SOLAR DEGRADATION	N/A	N/A	N/A	N/A		N/A		N/A	N/A	N/A	N/A	(5)			(2)

a. See page v. for Code Identification of Future Generating Unit Status.

b. NOTES

(1) Planned, Prospective, or Committed project.

(2) Solar capacity degrades by 0.5% every year

(3) Osprey CC Acquisition total capacity is available once Transmission Upgrades are in service, total Summer capacity goes up to 592MW and total Winter capacity goes up to 626MW

(4) Multiple 74.9 MWs units at different sites. For SPS, 40 MW of storage for 74.9 MW of Solar PV.

(5) Combustion Turbines Heat Rate upgrades for Combined Cycles

DUKE ENERGY FLORIDA

SCHEDULE 8

PLANNED AND PROSPECTIVE GENERATING FACILITY ADDITIONS AND CHANGES

AS OF JANUARY 1, 2024 THROUGH DECEMBER 31, 2033

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
												FIRM			
								CONST.	COM'L IN-	EXPECTED	GEN. MAX.	NET CAPABILITY			
	UNIT	LOCATION	UNIT	FUEL		FUEL TRANSPORT		START	SERVICE	RETIREMENT	NAMEPLATE	SUMMER	WINTER		
PLANT NAME	NO.	(COUNTY)	TYPE	PRI.	ALT.	PRI.	ALT.	MO. / YR	MO. / YR	MO. / YR	KW	MW	MW	STATUS[a]	NOTES[b]
UNKNOWN		UNKNOWN	PV	SO				09/2027	07/2028		299,600	30	0	P	(1) and (4)
UNKNOWN		UNKNOWN	SPS	SO				09/2027	07/2028		149,800	55	72	P	(1) and (4)
SOLAR DEGRADATION	N/A	N/A	N/A	N/A		N/A		N/A	N/A	N/A	N/A	(6)			(2)
UNKNOWN		UNKNOWN	PV	SO				09/2028	07/2029		374,500	37	0	P	(1) and (4)
UNKNOWN		UNKNOWN	SPS	SO				09/2028	07/2029		149,800	55	72	P	(1) and (4)
SOLAR DEGRADATION	N/A	N/A	N/A	N/A		N/A		N/A	N/A	N/A	N/A	(6)			(2)
UNKNOWN		UNKNOWN	PV	SO				09/2029	07/2030		449,400	45	0	P	(1) and (4)
UNKNOWN		UNKNOWN	SPS	SO				09/2029	07/2030		149,800	55	72	P	(1) and (4)
SOLAR DEGRADATION	N/A	N/A	N/A	N/A		N/A		N/A	N/A	N/A	N/A	(6)			(2)
UNKNOWN		UNKNOWN	PV	SO				09/2030	07/2031		599,200	60	0	P	(1) and (4)
SOLAR DEGRADATION	N/A	N/A	N/A	N/A		N/A		N/A	N/A	N/A	N/A	(6)			(2)
UNKNOWN	P1 - P2	UNKNOWN	CT	NG	DFO	FL	TK	07/2029	06/2032		455,000	430	466	P	(1)
UNKNOWN		UNKNOWN	PV	SO				09/2032	07/2033		599,200	60	0	P	(1) and (4)
SOLAR DEGRADATION	N/A	N/A	N/A	N/A		N/A		N/A	N/A	N/A	N/A	(7)			(2)
UNKNOWN	P3 - P4	UNKNOWN	CT	NG	DFO	FL	TK	07/2030	06/2033		455,000	430	466	P	(1)
UNKNOWN		UNKNOWN	PV	SO				09/2032	07/2033		599,200	60	0	P	(1) and (4)
SOLAR DEGRADATION	N/A	N/A	N/A	N/A		N/A		N/A	N/A	N/A	N/A	(7)			(2)

a. See page v. for Code Identification of Future Generating Unit Status.
b. NOTES
(1) Planned, Prospective, or Committed project.
(2) Solar capacity degrades by 0.5% every year
(3) Osprey CC Acquisition total capacity is available once Transmission Upgrades are in service, total Summer capacity goes up to 592MW and total Winter capacity goes up to 626MW
(4) Multiple 74.9 MWs units at different sites. For SPS, 40 MW of storage for 74.9 MW of Solar PV.
(5) Combustion Turbines Heat Rate upgrades for Combined Cycles

DUKE ENERGY FLORIDA

SCHEDULE 9
STATUS REPORT AND SPECIFICATIONS OF PROPOSED GENERATING FACILITIES
AS OF JANUARY 1, 2024

(1)	Plant Name and Unit Number:		**Mule Creek**	
(2)	Capacity			
	a. Nameplate (MWac):		74.9	
	b. Summer Firm (MWac):		42.7	
	c. Winter Firm (MWac):		-	
(3)	Technology Type:		PHOTOVOLTAIC	
(4)	Anticipated Construction Timing			
	a. Field construction start date:		4/2023	
	b. Commercial in-service date:		3/2024	(EXPECTED)
(5)	Fuel			
	a. Primary fuel:		SOLAR	
	b. Alternate fuel:		N/A	
(6)	Air Pollution Control Strategy:		N/A	
(7)	Cooling Method:		N/A	
(8)	Total Site Area:		~500-600 ACRES PER SOLAR SITE (74.9 MW)	
(9)	Construction Status:		PLANNED	
(10)	Certification Status:			
(11)	Status with Federal Agencies:			
(12)	Projected Unit Performance Data			
	a. Planned Outage Factor (POF):		N/A	%
	b. Forced Outage Factor (FOF):		N/A	%
	c. Equivalent Availability Factor (EAF):		N/A	%
	d. Resulting Capacity Factor (%):		~28	%
	e. Average Net Operating Heat Rate (ANOHR):		N/A	BTU/Kwh
(13)	Projected Unit Financial Data			
	a. Book Life (Years):		30	
	b. Total Installed Cost (In-service year $/Kw):		1,221.86	
	c. Direct Construction Cost ($/Kw ac):	($2024)		
	d. AFUDC Amount ($/Kw):			
	e. Escalation ($/Kw):			
	f. Fixed O&M ($/Kw dc-yr):	($2024)	17.17	
	g. Variable O&M ($/MWh):	($2024)	0.00	
	h. K Factor:		NO CALCULATION	

DUKE ENERGY FLORIDA

SCHEDULE 9
STATUS REPORT AND SPECIFICATIONS OF PROPOSED GENERATING FACILITIES
AS OF JANUARY 1, 2024

(1)	Plant Name and Unit Number:		**Winquepin**	
(2)	Capacity			
	a. Nameplate (MWac):		74.9	
	b. Summer Firm (MWac):		42.7	
	c. Winter Firm (MWac):		-	
(3)	Technology Type:		PHOTOVOLTAIC	
(4)	Anticipated Construction Timing			
	a. Field construction start date:		4/2023	
	b. Commercial in-service date:		3/2024	(EXPECTED)
(5)	Fuel			
	a. Primary fuel:		SOLAR	
	b. Alternate fuel:		N/A	
(6)	Air Pollution Control Strategy:		N/A	
(7)	Cooling Method:		N/A	
(8)	Total Site Area:		~500-600 ACRES PER SOLAR SITE (74.9 MW)	
(9)	Construction Status:		PLANNED	
(10)	Certification Status:			
(11)	Status with Federal Agencies:			
(12)	Projected Unit Performance Data			
	a. Planned Outage Factor (POF):		N/A	%
	b. Forced Outage Factor (FOF):		N/A	%
	c. Equivalent Availability Factor (EAF):		N/A	%
	d. Resulting Capacity Factor (%):		~28	%
	e. Average Net Operating Heat Rate (ANOHR):		N/A	BTU/Kwh
(13)	Projected Unit Financial Data			
	a. Book Life (Years):		30	
	b. Total Installed Cost (In-service year $/Kw):		1,221.86	
	c. Direct Construction Cost ($/Kw ac):	($2024)		
	d. AFUDC Amount ($/Kw):			
	e. Escalation ($/Kw):			
	f. Fixed O&M ($/Kw dc-yr):	($2024)	17.17	
	g. Variable O&M ($/MWh):	($2024)	0.00	
	h. K Factor:		NO CALCULATION	

DUKE ENERGY FLORIDA

SCHEDULE 9
STATUS REPORT AND SPECIFICATIONS OF PROPOSED GENERATING FACILITIES
AS OF JANUARY 1, 2024

(1)	Plant Name and Unit Number:		**Falmouth**	
(2)	Capacity			
	a. Nameplate (MWac):		74.9	
	b. Summer Firm (MWac):		42.7	
	c. Winter Firm (MWac):		-	
(3)	Technology Type:		PHOTOVOLTAIC	
(4)	Anticipated Construction Timing			
	a. Field construction start date:		6/2023	
	b. Commercial in-service date:		8/2024	(EXPECTED)
(5)	Fuel			
	a. Primary fuel:		SOLAR	
	b. Alternate fuel:		N/A	
(6)	Air Pollution Control Strategy:		N/A	
(7)	Cooling Method:		N/A	
(8)	Total Site Area:		~500-600 ACRES PER SOLAR SITE (74.9 MW)	
(9)	Construction Status:		PLANNED	
(10)	Certification Status:			
(11)	Status with Federal Agencies:			
(12)	Projected Unit Performance Data			
	a. Planned Outage Factor (POF):		N/A	%
	b. Forced Outage Factor (FOF):		N/A	%
	c. Equivalent Availability Factor (EAF):		N/A	%
	d. Resulting Capacity Factor (%):		~28	%
	e. Average Net Operating Heat Rate (ANOHR):		N/A	BTU/Kwh
(13)	Projected Unit Financial Data			
	a. Book Life (Years):		30	
	b. Total Installed Cost (In-service year $/Kw):		1,221.86	
	c. Direct Construction Cost ($/Kw ac):	($2024)		
	d. AFUDC Amount ($/Kw):			
	e. Escalation ($/Kw):			
	f. Fixed O&M ($/Kw dc-yr):	($2024)	17.17	
	g. Variable O&M ($/MWh):	($2024)	0.00	
	h. K Factor:		NO CALCULATION	

DUKE ENERGY FLORIDA

SCHEDULE 9
STATUS REPORT AND SPECIFICATIONS OF PROPOSED GENERATING FACILITIES
AS OF JANUARY 1, 2024

(1)	Plant Name and Unit Number:	**County Line**	
(2)	Capacity		
	a. Nameplate (MWac):	74.9	
	b. Summer Firm (MWac):	42.7	
	c. Winter Firm (MWac):	-	
(3)	Technology Type:	PHOTOVOLTAIC	
(4)	Anticipated Construction Timing		
	a. Field construction start date:	12/2023	
	b. Commercial in-service date:	10/2024	(EXPECTED)
(5)	Fuel		
	a. Primary fuel:	SOLAR	
	b. Alternate fuel:	N/A	
(6)	Air Pollution Control Strategy:	N/A	
(7)	Cooling Method:	N/A	
(8)	Total Site Area:	~500-600 ACRES PER SOLAR SITE (74.9 MW)	
(9)	Construction Status:	PLANNED	
(10)	Certification Status:		
(11)	Status with Federal Agencies:		
(12)	Projected Unit Performance Data		
	a. Planned Outage Factor (POF):	N/A %	
	b. Forced Outage Factor (FOF):	N/A %	
	c. Equivalent Availability Factor (EAF):	N/A %	
	d. Resulting Capacity Factor (%):	~28 %	
	e. Average Net Operating Heat Rate (ANOHR):	N/A BTU/Kwh	
(13)	Projected Unit Financial Data		
	a. Book Life (Years):	30	
	b. Total Installed Cost (In-service year $/Kw):	1,221.86	
	c. Direct Construction Cost ($/Kw ac): ($2024)		
	d. AFUDC Amount ($/Kw):		
	e. Escalation ($/Kw):		
	f. Fixed O&M ($/Kw dc-yr): ($2024)	17.17	
	g. Variable O&M ($/MWh): ($2024)	0.00	
	h. K Factor:	NO CALCULATION	

DUKE ENERGY FLORIDA

SCHEDULE 9
STATUS REPORT AND SPECIFICATIONS OF PROPOSED GENERATING FACILITIES
AS OF JANUARY 1, 2024

(1)	Plant Name and Unit Number:		**Sundance**	
(2)	Capacity			
	a. Nameplate (MWac):		74.9	
	b. Summer Firm (MWac):		18.7	
	c. Winter Firm (MWac):		-	
(3)	Technology Type:		PHOTOVOLTAIC	
(4)	Anticipated Construction Timing			
	a. Field construction start date:		4/2024	
	b. Commercial in-service date:		3/2025	(EXPECTED)
(5)	Fuel			
	a. Primary fuel:		SOLAR	
	b. Alternate fuel:		N/A	
(6)	Air Pollution Control Strategy:		N/A	
(7)	Cooling Method:		N/A	
(8)	Total Site Area:		~500-600 ACRES PER SOLAR SITE (74.9 MW)	
(9)	Construction Status:		PLANNED	
(10)	Certification Status:			
(11)	Status with Federal Agencies:			
(12)	Projected Unit Performance Data			
	a. Planned Outage Factor (POF):		N/A	%
	b. Forced Outage Factor (FOF):		N/A	%
	c. Equivalent Availability Factor (EAF):		N/A	%
	d. Resulting Capacity Factor (%):		~27	%
	e. Average Net Operating Heat Rate (ANOHR):		N/A	BTU/Kwh
(13)	Projected Unit Financial Data			
	a. Book Life (Years):		30	
	b. Total Installed Cost (In-service year $/Kw):		1,415.40	
	c. Direct Construction Cost ($/Kw ac):	($2024)		
	d. AFUDC Amount ($/Kw):			
	e. Escalation ($/Kw):			
	f. Fixed O&M ($/Kw dc-yr):	($2024)	17.17	
	g. Variable O&M ($/MWh):	($2024)	0.00	
	h. K Factor:		NO CALCULATION	

DUKE ENERGY FLORIDA

SCHEDULE 9
STATUS REPORT AND SPECIFICATIONS OF PROPOSED GENERATING FACILITIES
AS OF JANUARY 1, 2024

(1)	Plant Name and Unit Number:		**Bailey Mill**	
(2)	Capacity			
	a. Nameplate (MWac):		74.9	
	b. Summer Firm (MWac):		18.7	
	c. Winter Firm (MWac):		-	
(3)	Technology Type:		PHOTOVOLTAIC	
(4)	Anticipated Construction Timing			
	a. Field construction start date:		4/2025	
	b. Commercial in-service date:		12/2025	(EXPECTED)
(5)	Fuel			
	a. Primary fuel:		SOLAR	
	b. Alternate fuel:		N/A	
(6)	Air Pollution Control Strategy:		N/A	
(7)	Cooling Method:		N/A	
(8)	Total Site Area:		~500-600 ACRES PER SOLAR SITE (74.9 MW)	
(9)	Construction Status:		PLANNED	
(10)	Certification Status:			
(11)	Status with Federal Agencies:			
(12)	Projected Unit Performance Data			
	a. Planned Outage Factor (POF):		N/A %	
	b. Forced Outage Factor (FOF):		N/A %	
	c. Equivalent Availability Factor (EAF):		N/A %	
	d. Resulting Capacity Factor (%):		~27 %	
	e. Average Net Operating Heat Rate (ANOHR):		N/A BTU/Kwh	
(13)	Projected Unit Financial Data			
	a. Book Life (Years):		30	
	b. Total Installed Cost (In-service year $/Kw):		1,415.40	
	c. Direct Construction Cost ($/Kw ac):	($2024)		
	d. AFUDC Amount ($/Kw):			
	e. Escalation ($/Kw):			
	f. Fixed O&M ($/Kw dc-yr):	($2024)	17.17	
	g. Variable O&M ($/MWh):	($2024)	0.00	
	h. K Factor:		NO CALCULATION	

DUKE ENERGY FLORIDA

SCHEDULE 9
STATUS REPORT AND SPECIFICATIONS OF PROPOSED GENERATING FACILITIES
AS OF JANUARY 1, 2024

(1)	Plant Name and Unit Number:		**Half Moon**	
(2)	Capacity			
	a. Nameplate (MWac):		74.9	
	b. Summer Firm (MWac):		18.7	
	c. Winter Firm (MWac):		-	
(3)	Technology Type:		PHOTOVOLTAIC	
(4)	Anticipated Construction Timing			
	a. Field construction start date:		4/2025	
	b. Commercial in-service date:		12/2025	(EXPECTED)
(5)	Fuel			
	a. Primary fuel:		SOLAR	
	b. Alternate fuel:		N/A	
(6)	Air Pollution Control Strategy:		N/A	
(7)	Cooling Method:		N/A	
(8)	Total Site Area:		~500-600 ACRES PER SOLAR SITE (74.9 MW)	
(9)	Construction Status:		PLANNED	
(10)	Certification Status:			
(11)	Status with Federal Agencies:			
(12)	Projected Unit Performance Data			
	a. Planned Outage Factor (POF):		N/A %	
	b. Forced Outage Factor (FOF):		N/A %	
	c. Equivalent Availability Factor (EAF):		N/A %	
	d. Resulting Capacity Factor (%):		~27 %	
	e. Average Net Operating Heat Rate (ANOHR):		N/A BTU/Kwh	
(13)	Projected Unit Financial Data			
	a. Book Life (Years):		30	
	b. Total Installed Cost (In-service year $/Kw):		1,428.31	
	c. Direct Construction Cost ($/Kw ac):	($2024)		
	d. AFUDC Amount ($/Kw):			
	e. Escalation ($/Kw):			
	f. Fixed O&M ($/Kw dc-yr):	($2024)	17.17	
	g. Variable O&M ($/MWh):	($2024)	0.00	
	h. K Factor:		NO CALCULATION	

DUKE ENERGY FLORIDA

SCHEDULE 9
STATUS REPORT AND SPECIFICATIONS OF PROPOSED GENERATING FACILITIES
AS OF JANUARY 1, 2024

(1)	Plant Name and Unit Number:		**Rattler**	
(2)	Capacity			
	a. Nameplate (MWac):		74.9	
	b. Summer Firm (MWac):		18.7	
	c. Winter Firm (MWac):		-	
(3)	Technology Type:		PHOTOVOLTAIC	
(4)	Anticipated Construction Timing			
	a. Field construction start date:		4/2025	
	b. Commercial in-service date:		12/2025	(EXPECTED)
(5)	Fuel			
	a. Primary fuel:		SOLAR	
	b. Alternate fuel:		N/A	
(6)	Air Pollution Control Strategy:		N/A	
(7)	Cooling Method:		N/A	
(8)	Total Site Area:		~500-600 ACRES PER SOLAR SITE (74.9 MW)	
(9)	Construction Status:		PLANNED	
(10)	Certification Status:			
(11)	Status with Federal Agencies:			
(12)	Projected Unit Performance Data			
	a. Planned Outage Factor (POF):		N/A	%
	b. Forced Outage Factor (FOF):		N/A	%
	c. Equivalent Availability Factor (EAF):		N/A	%
	d. Resulting Capacity Factor (%):		~27	%
	e. Average Net Operating Heat Rate (ANOHR):		N/A	BTU/Kwh
(13)	Projected Unit Financial Data			
	a. Book Life (Years):		30	
	b. Total Installed Cost (In-service year $/Kw):		1,428.31	
	c. Direct Construction Cost ($/Kw ac):	($2024)		
	d. AFUDC Amount ($/Kw):			
	e. Escalation ($/Kw):			
	f. Fixed O&M ($/Kw dc-yr):	($2024)	17.17	
	g. Variable O&M ($/MWh):	($2024)	0.00	
	h. K Factor:		NO CALCULATION	

DUKE ENERGY FLORIDA

SCHEDULE 9
STATUS REPORT AND SPECIFICATIONS OF PROPOSED GENERATING FACILITIES
AS OF JANUARY 1, 2024

(1)	Plant Name and Unit Number:	**TBD**		
(2)	Capacity			
	a. Nameplate (MWac):	224.7		
	b. Summer Firm (MWac):	56.2		
	c. Winter Firm (MWac):	-		
(3)	Technology Type:	PHOTOVOLTAIC		
(4)	Anticipated Construction Timing			
	a. Field construction start date:	9/2025		
	b. Commercial in-service date:	6/2026	(EXPECTED)	
(5)	Fuel			
	a. Primary fuel:	SOLAR		
	b. Alternate fuel:	N/A		
(6)	Air Pollution Control Strategy:	N/A		
(7)	Cooling Method:	N/A		
(8)	Total Site Area:	~500-600 ACRES PER SOLAR SITE (74.9 MW)		
(9)	Construction Status:	PLANNED		
(10)	Certification Status:			
(11)	Status with Federal Agencies:			
(12)	Projected Unit Performance Data			
	a. Planned Outage Factor (POF):		N/A	%
	b. Forced Outage Factor (FOF):		N/A	%
	c. Equivalent Availability Factor (EAF):		N/A	%
	d. Resulting Capacity Factor (%):		~27	%
	e. Average Net Operating Heat Rate (ANOHR):		N/A	BTU/Kwh
(13)	Projected Unit Financial Data			
	a. Book Life (Years):		30	
	b. Total Installed Cost (In-service year $/Kw):		1,428.34	
	c. Direct Construction Cost ($/Kw ac): ($2024)			
	d. AFUDC Amount ($/Kw):			
	e. Escalation ($/Kw):			
	f. Fixed O&M ($/Kw dc-yr): ($2024)		17.17	
	g. Variable O&M ($/MWh): ($2024)		0.00	
	h. K Factor:	NO CALCULATION		

DUKE ENERGY FLORIDA

SCHEDULE 9
STATUS REPORT AND SPECIFICATIONS OF PROPOSED GENERATING FACILITIES
AS OF JANUARY 1, 2024

(1)	Plant Name and Unit Number:	**TBD**	
(2)	Capacity		
	a. Nameplate (MWac):	149.8	
	b. Summer Firm (MWac):	37.5	
	c. Winter Firm (MWac):	-	
(3)	Technology Type:	PHOTOVOLTAIC	
(4)	Anticipated Construction Timing		
	a. Field construction start date:	4/2026	
	b. Commercial in-service date:	12/2026	(EXPECTED)
(5)	Fuel		
	a. Primary fuel:	SOLAR	
	b. Alternate fuel:	N/A	
(6)	Air Pollution Control Strategy:	N/A	
(7)	Cooling Method:	N/A	
(8)	Total Site Area:	~500-600 ACRES PER SOLAR SITE (74.9 MW)	
(9)	Construction Status:	PLANNED	
(10)	Certification Status:		
(11)	Status with Federal Agencies:		
(12)	Projected Unit Performance Data		
	a. Planned Outage Factor (POF):	N/A %	
	b. Forced Outage Factor (FOF):	N/A %	
	c. Equivalent Availability Factor (EAF):	N/A %	
	d. Resulting Capacity Factor (%):	~27 %	
	e. Average Net Operating Heat Rate (ANOHR):	N/A BTU/Kwh	
(13)	Projected Unit Financial Data		
	a. Book Life (Years):	30	
	b. Total Installed Cost (In-service year $/Kw):	1,419.08	
	c. Direct Construction Cost ($/Kw ac): ($2024)		
	d. AFUDC Amount ($/Kw):		
	e. Escalation ($/Kw):		
	f. Fixed O&M ($/Kw dc-yr): ($2024)	17.17	
	g. Variable O&M ($/MWh): ($2024)	0.00	
	h. K Factor:	NO CALCULATION	

DUKE ENERGY FLORIDA

SCHEDULE 9
STATUS REPORT AND SPECIFICATIONS OF PROPOSED GENERATING FACILITIES
AS OF JANUARY 1, 2024

(1)	Plant Name and Unit Number:	**TBD**		
(2)	Capacity			
	a. Nameplate (MWac):	100.0		
	b. Summer Firm (MWac):	90.0		
	c. Winter Firm (MWac):	90.0		
(3)	Technology Type:	BATTERY STORAGE		
(4)	Anticipated Construction Timing			
	a. Field construction start date:	7/2026		
	b. Commercial in-service date:	3/2027	(EXPECTED)	
(5)	Fuel			
	a. Primary fuel:	N/A		
	b. Alternate fuel:	N/A		
(6)	Air Pollution Control Strategy:	N/A		
(7)	Cooling Method:	N/A		
(8)	Total Site Area:	~1 ACRE / 5 MW		
(9)	Construction Status:	PLANNED		
(10)	Certification Status:			
(11)	Status with Federal Agencies:			
(12)	Projected Unit Performance Data			
	a. Planned Outage Factor (POF):		N/A	%
	b. Forced Outage Factor (FOF):		N/A	%
	c. Equivalent Availability Factor (EAF):		N/A	%
	d. Resulting Capacity Factor (%):		~10	%
	e. Average Net Operating Heat Rate (ANOHR):		N/A	BTU/Kwh
(13)	Projected Unit Financial Data			
	a. Book Life (Years):		15	
	b. Total Installed Cost (In-service year $/Kw):		1,650.00	
	c. Direct Construction Cost ($/Kw ac): ($2024)			
	d. AFUDC Amount ($/Kw):			
	e. Escalation ($/Kw):			
	f. Fixed O&M ($/Kw dc-yr): ($2024)		30.00	
	g. Variable O&M ($/MWh): ($2024)		0.00	
	h. K Factor:	NO CALCULATION		

DUKE ENERGY FLORIDA

SCHEDULE 9
STATUS REPORT AND SPECIFICATIONS OF PROPOSED GENERATING FACILITIES
AS OF JANUARY 1, 2024

(1)	Plant Name and Unit Number:		**TBD**	
(2)	Capacity			
	a. Nameplate (MWac):		224.7	
	b. Summer Firm (MWac):		56.2	
	c. Winter Firm (MWac):		-	
(3)	Technology Type:		PHOTOVOLTAIC	
(4)	Anticipated Construction Timing			
	a. Field construction start date:		9/2026	
	b. Commercial in-service date:		6/2027	(EXPECTED)
(5)	Fuel			
	a. Primary fuel:		SOLAR	
	b. Alternate fuel:		N/A	
(6)	Air Pollution Control Strategy:		N/A	
(7)	Cooling Method:		N/A	
(8)	Total Site Area:		~500-600 ACRES PER SOLAR SITE (74.9 MW)	
(9)	Construction Status:		PLANNED	
(10)	Certification Status:			
(11)	Status with Federal Agencies:			
(12)	Projected Unit Performance Data			
	a. Planned Outage Factor (POF):		N/A	%
	b. Forced Outage Factor (FOF):		N/A	%
	c. Equivalent Availability Factor (EAF):		N/A	%
	d. Resulting Capacity Factor (%):		~27	%
	e. Average Net Operating Heat Rate (ANOHR):		N/A	BTU/Kwh
(13)	Projected Unit Financial Data			
	a. Book Life (Years):		30	
	b. Total Installed Cost (In-service year $/Kw):		1,409.96	
	c. Direct Construction Cost ($/Kw ac):	($2024)		
	d. AFUDC Amount ($/Kw):			
	e. Escalation ($/Kw):			
	f. Fixed O&M ($/Kw dc-yr):	($2024)	17.17	
	g. Variable O&M ($/MWh):	($2024)	0.00	
	h. K Factor:		NO CALCULATION	

DUKE ENERGY FLORIDA

SCHEDULE 9
STATUS REPORT AND SPECIFICATIONS OF PROPOSED GENERATING FACILITIES
AS OF JANUARY 1, 2024

(1)	Plant Name and Unit Number:		**TBD**	
(2)	Capacity			
	a. Nameplate (MWac):		149.8	
	b. Summer Firm (MWac):		37.5	
	c. Winter Firm (MWac):		-	
(3)	Technology Type:		PHOTOVOLTAIC	
(4)	Anticipated Construction Timing			
	a. Field construction start date:		4/2027	
	b. Commercial in-service date:		12/2027	(EXPECTED)
(5)	Fuel			
	a. Primary fuel:		SOLAR	
	b. Alternate fuel:		N/A	
(6)	Air Pollution Control Strategy:		N/A	
(7)	Cooling Method:		N/A	
(8)	Total Site Area:		~500-600 ACRES PER SOLAR SITE (74.9 MW)	
(9)	Construction Status:		PLANNED	
(10)	Certification Status:			
(11)	Status with Federal Agencies:			
(12)	Projected Unit Performance Data			
	a. Planned Outage Factor (POF):		N/A	%
	b. Forced Outage Factor (FOF):		N/A	%
	c. Equivalent Availability Factor (EAF):		N/A	%
	d. Resulting Capacity Factor (%):		~27	%
	e. Average Net Operating Heat Rate (ANOHR):		N/A	BTU/Kwh
(13)	Projected Unit Financial Data			
	a. Book Life (Years):		30	
	b. Total Installed Cost (In-service year $/Kw):		1,409.96	
	c. Direct Construction Cost ($/Kw ac):	($2024)		
	d. AFUDC Amount ($/Kw):			
	e. Escalation ($/Kw):			
	f. Fixed O&M ($/Kw dc-yr):	($2024)	17.17	
	g. Variable O&M ($/MWh):	($2024)	0.00	
	h. K Factor:		NO CALCULATION	

DUKE ENERGY FLORIDA

SCHEDULE 9
STATUS REPORT AND SPECIFICATIONS OF PROPOSED GENERATING FACILITIES
AS OF JANUARY 1, 2024

(1)	Plant Name and Unit Number:	**TBD**	
(2)	Capacity		
	a. Nameplate (MWac):	299.6	
	b. Summer Firm (MWac):	30.0	
	c. Winter Firm (MWac):	-	
(3)	Technology Type:	PHOTOVOLTAIC	
(4)	Anticipated Construction Timing		
	a. Field construction start date:	9/2027	
	b. Commercial in-service date:	7/2028	(EXPECTED)
(5)	Fuel		
	a. Primary fuel:	SOLAR	
	b. Alternate fuel:	N/A	
(6)	Air Pollution Control Strategy:	N/A	
(7)	Cooling Method:	N/A	
(8)	Total Site Area:	~500-600 ACRES PER SOLAR SITE (74.9 MW)	
(9)	Construction Status:	PLANNED	
(10)	Certification Status:		
(11)	Status with Federal Agencies:		
(12)	Projected Unit Performance Data		
	a. Planned Outage Factor (POF):	N/A %	
	b. Forced Outage Factor (FOF):	N/A %	
	c. Equivalent Availability Factor (EAF):	N/A %	
	d. Resulting Capacity Factor (%):	~27 %	
	e. Average Net Operating Heat Rate (ANOHR):	N/A BTU/Kwh	
(13)	Projected Unit Financial Data		
	a. Book Life (Years):	30	
	b. Total Installed Cost (In-service year $/Kw):	1,648.99	
	c. Direct Construction Cost ($/Kw ac): ($2024)		
	d. AFUDC Amount ($/Kw):		
	e. Escalation ($/Kw):		
	f. Fixed O&M ($/Kw dc-yr): ($2024)		
	g. Variable O&M ($/MWh): ($2024)	0.00	
	h. K Factor:	NO CALCULATION	

DUKE ENERGY FLORIDA

SCHEDULE 9
STATUS REPORT AND SPECIFICATIONS OF PROPOSED GENERATING FACILITIES
AS OF JANUARY 1, 2024

(1)	Plant Name and Unit Number:	**TBD**		
(2)	Capacity			
	a. Nameplate (MWac):	149.8		
	b. Summer Firm (MWac):	55.0		
	c. Winter Firm (MWac):	72.0		
(3)	Technology Type:	PHOTOVOLTAIC WITH BATTERY STORAGE		
(4)	Anticipated Construction Timing			
	a. Field construction start date:	9/2027		
	b. Commercial in-service date:	7/2028	(EXPECTED)	
(5)	Fuel			
	a. Primary fuel:	SOLAR		
	b. Alternate fuel:	N/A		
(6)	Air Pollution Control Strategy:	N/A		
(7)	Cooling Method:	N/A		
(8)	Total Site Area:	~500-600 ACRES PER SOLAR SITE (74.9 MW)		
(9)	Construction Status:	PLANNED		
(10)	Certification Status:			
(11)	Status with Federal Agencies:			
(12)	Projected Unit Performance Data			
	a. Planned Outage Factor (POF):		N/A	%
	b. Forced Outage Factor (FOF):		N/A	%
	c. Equivalent Availability Factor (EAF):		N/A	%
	d. Resulting Capacity Factor (%):		~34	%
	e. Average Net Operating Heat Rate (ANOHR):		N/A	BTU/Kwh
(13)	Projected Unit Financial Data			
	a. Book Life (Years):		30	
	b. Total Installed Cost (In-service year $/Kw):		2,470.83	
	c. Direct Construction Cost ($/Kw ac): ($2024)			
	d. AFUDC Amount ($/Kw):			
	e. Escalation ($/Kw):			
	f. Fixed O&M ($/Kw dc-yr): ($2024)			
	g. Variable O&M ($/MWh): ($2024)		0.00	
	h. K Factor:	NO CALCULATION		

DUKE ENERGY FLORIDA

SCHEDULE 9
STATUS REPORT AND SPECIFICATIONS OF PROPOSED GENERATING FACILITIES
AS OF JANUARY 1, 2024

(1)	Plant Name and Unit Number:		**TBD**	
(2)	Capacity			
	a. Nameplate (MWac):		374.5	
	b. Summer Firm (MWac):		37.5	
	c. Winter Firm (MWac):		-	
(3)	Technology Type:		PHOTOVOLTAIC	
(4)	Anticipated Construction Timing			
	a. Field construction start date:		9/2028	
	b. Commercial in-service date:		7/2029	(EXPECTED)
(5)	Fuel			
	a. Primary fuel:		SOLAR	
	b. Alternate fuel:		N/A	
(6)	Air Pollution Control Strategy:		N/A	
(7)	Cooling Method:		N/A	
(8)	Total Site Area:		~500-600 ACRES PER SOLAR SITE (74.9 MW)	
(9)	Construction Status:		PLANNED	
(10)	Certification Status:			
(11)	Status with Federal Agencies:			
(12)	Projected Unit Performance Data			
	a. Planned Outage Factor (POF):		N/A	%
	b. Forced Outage Factor (FOF):		N/A	%
	c. Equivalent Availability Factor (EAF):		N/A	%
	d. Resulting Capacity Factor (%):		~27	%
	e. Average Net Operating Heat Rate (ANOHR):		N/A	BTU/Kwh
(13)	Projected Unit Financial Data			
	a. Book Life (Years):		30	
	b. Total Installed Cost (In-service year $/Kw):		1,632.89	
	c. Direct Construction Cost ($/Kw ac):	($2024)		
	d. AFUDC Amount ($/Kw):			
	e. Escalation ($/Kw):			
	f. Fixed O&M ($/Kw dc-yr):	($2024)		
	g. Variable O&M ($/MWh):	($2024)	0.00	
	h. K Factor:		NO CALCULATION	

DUKE ENERGY FLORIDA

SCHEDULE 9
STATUS REPORT AND SPECIFICATIONS OF PROPOSED GENERATING FACILITIES
AS OF JANUARY 1, 2024

(1)	Plant Name and Unit Number:	**TBD**		
(2)	Capacity			
	a. Nameplate (MWac):	149.8		
	b. Summer Firm (MWac):	55.0		
	c. Winter Firm (MWac):	72.0		
(3)	Technology Type:	PHOTOVOLTAIC WITH BATTERY STORAGE		
(4)	Anticipated Construction Timing			
	a. Field construction start date:	9/2028		
	b. Commercial in-service date:	7/2029	(EXPECTED)	
(5)	Fuel			
	a. Primary fuel:	SOLAR		
	b. Alternate fuel:	N/A		
(6)	Air Pollution Control Strategy:	N/A		
(7)	Cooling Method:	N/A		
(8)	Total Site Area:	~500-600 ACRES PER SOLAR SITE (74.9 MW)		
(9)	Construction Status:	PLANNED		
(10)	Certification Status:			
(11)	Status with Federal Agencies:			
(12)	Projected Unit Performance Data			
	a. Planned Outage Factor (POF):		N/A	%
	b. Forced Outage Factor (FOF):		N/A	%
	c. Equivalent Availability Factor (EAF):		N/A	%
	d. Resulting Capacity Factor (%):		~34	%
	e. Average Net Operating Heat Rate (ANOHR):		N/A	BTU/Kwh
(13)	Projected Unit Financial Data			
	a. Book Life (Years):		30	
	b. Total Installed Cost (In-service year $/Kw):		2,444.11	
	c. Direct Construction Cost ($/Kw ac): ($2024)			
	d. AFUDC Amount ($/Kw):			
	e. Escalation ($/Kw):			
	f. Fixed O&M ($/Kw dc-yr): ($2024)			
	g. Variable O&M ($/MWh): ($2024)		0.00	
	h. K Factor:	NO CALCULATION		

DUKE ENERGY FLORIDA

SCHEDULE 9
STATUS REPORT AND SPECIFICATIONS OF PROPOSED GENERATING FACILITIES
AS OF JANUARY 1, 2024

(1)	Plant Name and Unit Number:		**TBD**	
(2)	Capacity			
	a. Nameplate (MWac):		449.4	
	b. Summer Firm (MWac):		44.9	
	c. Winter Firm (MWac):		-	
(3)	Technology Type:		PHOTOVOLTAIC	
(4)	Anticipated Construction Timing			
	a. Field construction start date:		9/2029	
	b. Commercial in-service date:		7/2030	(EXPECTED)
(5)	Fuel			
	a. Primary fuel:		SOLAR	
	b. Alternate fuel:		N/A	
(6)	Air Pollution Control Strategy:		N/A	
(7)	Cooling Method:		N/A	
(8)	Total Site Area:		~500-600 ACRES PER SOLAR SITE (74.9 MW)	
(9)	Construction Status:		PLANNED	
(10)	Certification Status:			
(11)	Status with Federal Agencies:			
(12)	Projected Unit Performance Data			
	a. Planned Outage Factor (POF):			N/A %
	b. Forced Outage Factor (FOF):			N/A %
	c. Equivalent Availability Factor (EAF):			N/A %
	d. Resulting Capacity Factor (%):			~27 %
	e. Average Net Operating Heat Rate (ANOHR):			N/A BTU/Kwh
(13)	Projected Unit Financial Data			
	a. Book Life (Years):			30
	b. Total Installed Cost (In-service year $/Kw):			1,617.30
	c. Direct Construction Cost ($/Kw ac):	($2024)		
	d. AFUDC Amount ($/Kw):			
	e. Escalation ($/Kw):			
	f. Fixed O&M ($/Kw dc-yr):	($2024)		
	g. Variable O&M ($/MWh):	($2024)		0.00
	h. K Factor:		NO CALCULATION	

DUKE ENERGY FLORIDA

SCHEDULE 9
STATUS REPORT AND SPECIFICATIONS OF PROPOSED GENERATING FACILITIES
AS OF JANUARY 1, 2024

(1)	Plant Name and Unit Number:	**TBD**		
(2)	Capacity			
	a. Nameplate (MWac):	149.8		
	b. Summer Firm (MWac):	55.0		
	c. Winter Firm (MWac):	72.0		
(3)	Technology Type:	PHOTOVOLTAIC WITH BATTERY STORAGE		
(4)	Anticipated Construction Timing			
	a. Field construction start date:	9/2029		
	b. Commercial in-service date:	7/2030	(EXPECTED)	
(5)	Fuel			
	a. Primary fuel:	SOLAR		
	b. Alternate fuel:	N/A		
(6)	Air Pollution Control Strategy:	N/A		
(7)	Cooling Method:	N/A		
(8)	Total Site Area:	~500-600 ACRES PER SOLAR SITE (74.9 MW)		
(9)	Construction Status:	PLANNED		
(10)	Certification Status:			
(11)	Status with Federal Agencies:			
(12)	Projected Unit Performance Data			
	a. Planned Outage Factor (POF):		N/A	%
	b. Forced Outage Factor (FOF):		N/A	%
	c. Equivalent Availability Factor (EAF):		N/A	%
	d. Resulting Capacity Factor (%):		~34	%
	e. Average Net Operating Heat Rate (ANOHR):		N/A	BTU/Kwh
(13)	Projected Unit Financial Data			
	a. Book Life (Years):		30	
	b. Total Installed Cost (In-service year $/Kw):		2,418.04	
	c. Direct Construction Cost ($/Kw ac): ($2024)			
	d. AFUDC Amount ($/Kw):			
	e. Escalation ($/Kw):			
	f. Fixed O&M ($/Kw dc-yr): ($2024)			
	g. Variable O&M ($/MWh): ($2024)		0.00	
	h. K Factor:	NO CALCULATION		

DUKE ENERGY FLORIDA

SCHEDULE 9
STATUS REPORT AND SPECIFICATIONS OF PROPOSED GENERATING FACILITIES
AS OF JANUARY 1, 2024

(1)	Plant Name and Unit Number:		**TBD**	
(2)	Capacity			
	a. Nameplate (MWac):		599.2	
	b. Summer Firm (MWac):		59.9	
	c. Winter Firm (MWac):		-	
(3)	Technology Type:		PHOTOVOLTAIC	
(4)	Anticipated Construction Timing			
	a. Field construction start date:		9/2030	
	b. Commercial in-service date:		7/2031	(EXPECTED)
(5)	Fuel			
	a. Primary fuel:		SOLAR	
	b. Alternate fuel:		N/A	
(6)	Air Pollution Control Strategy:		N/A	
(7)	Cooling Method:		N/A	
(8)	Total Site Area:		~500-600 ACRES PER SOLAR SITE (74.9 MW)	
(9)	Construction Status:		PLANNED	
(10)	Certification Status:			
(11)	Status with Federal Agencies:			
(12)	Projected Unit Performance Data			
	a. Planned Outage Factor (POF):		N/A %	
	b. Forced Outage Factor (FOF):		N/A %	
	c. Equivalent Availability Factor (EAF):		N/A %	
	d. Resulting Capacity Factor (%):		~27 %	
	e. Average Net Operating Heat Rate (ANOHR):		N/A BTU/Kwh	
(13)	Projected Unit Financial Data			
	a. Book Life (Years):		30	
	b. Total Installed Cost (In-service year $/Kw):		1,602.23	
	c. Direct Construction Cost ($/Kw ac):	($2024)		
	d. AFUDC Amount ($/Kw):			
	e. Escalation ($/Kw):			
	f. Fixed O&M ($/Kw dc-yr):	($2024)		
	g. Variable O&M ($/MWh):	($2024)	0.00	
	h. K Factor:		NO CALCULATION	

DUKE ENERGY FLORIDA

SCHEDULE 9
STATUS REPORT AND SPECIFICATIONS OF PROPOSED GENERATING FACILITIES
AS OF JANUARY 1, 2024

(1)	Plant Name and Unit Number:		**Undesignated CTs P1-P2**	
(2)	Capacity			
	a. Summer (MWs):		215	
	b. Winter (MWs):		235	
(3)	Technology Type:		COMBUSTION TURBINE	
(4)	Anticipated Construction Timing			
	a. Field construction start date:		7/2029	
	b. Commercial in-service date:		6/2032	(EXPECTED)
(5)	Fuel			
	a. Primary fuel:		NATURAL GAS	
	b. Alternate fuel:		DISTILLATE FUEL OIL	
(6)	Air Pollution Control Strategy:		Dry Low Nox Combustion	
(7)	Cooling Method:		N/A	
(8)	Total Site Area:		UNKNOWN	
(9)	Construction Status:		PLANNED	
(10)	Certification Status:		PLANNED	
(11)	Status with Federal Agencies:		PLANNED	
(12)	Projected Unit Performance Data			
	a. Planned Outage Factor (POF):		3.00	%
	b. Forced Outage Factor (FOF):		2.00	%
	c. Equivalent Availability Factor (EAF):		95.06	
	d. Resulting Capacity Factor (%):		1.9	%
	e. Average Net Operating Heat Rate (ANOHR):		10,487	BTU/kWh
(13)	Projected Unit Financial Data			
	a. Book Life (Years):		35	
	b. Total Installed Cost (In-service year $/kW):		1,421.8	
	c. Direct Construction Cost ($/kW):	($2024)	1,239.7	
	d. AFUDC Amount ($/kW):		180.9	
	e. Escalation ($/kW):		1.2	
	f. Fixed O&M ($/kW-yr):	($2024)	2.86	
	g. Variable O&M ($/MWh):	($2024)	9.03	
	h. K Factor:		NO CALCULATION	

NOTES
Total Installed Cost includes gas expansion, transmission interconnection and integration
$/kW values are based on Summer capacity
Fixed O&M cost does not include firm gas transportation costs

DUKE ENERGY FLORIDA

SCHEDULE 9
STATUS REPORT AND SPECIFICATIONS OF PROPOSED GENERATING FACILITIES
AS OF JANUARY 1, 2024

(1)	Plant Name and Unit Number:		**TBD**	
(2)	Capacity			
	a. Nameplate (MWac):		599.2	
	b. Summer Firm (MWac):		59.9	
	c. Winter Firm (MWac):		-	
(3)	Technology Type:		PHOTOVOLTAIC	
(4)	Anticipated Construction Timing			
	a. Field construction start date:		9/2031	
	b. Commercial in-service date:		7/2032	(EXPECTED)
(5)	Fuel			
	a. Primary fuel:		SOLAR	
	b. Alternate fuel:		N/A	
(6)	Air Pollution Control Strategy:		N/A	
(7)	Cooling Method:		N/A	
(8)	Total Site Area:		~500-600 ACRES PER SOLAR SITE (74.9 MW)	
(9)	Construction Status:		PLANNED	
(10)	Certification Status:			
(11)	Status with Federal Agencies:			
(12)	Projected Unit Performance Data			
	a. Planned Outage Factor (POF):			N/A %
	b. Forced Outage Factor (FOF):			N/A %
	c. Equivalent Availability Factor (EAF):			N/A %
	d. Resulting Capacity Factor (%):			~27 %
	e. Average Net Operating Heat Rate (ANOHR):			N/A BTU/Kwh
(13)	Projected Unit Financial Data			
	a. Book Life (Years):		30	
	b. Total Installed Cost (In-service year $/Kw):		1,587.67	
	c. Direct Construction Cost ($/Kw ac):	($2024)		
	d. AFUDC Amount ($/Kw):			
	e. Escalation ($/Kw):			
	f. Fixed O&M ($/Kw dc-yr):	($2024)		
	g. Variable O&M ($/MWh):	($2024)	0.00	
	h. K Factor:		NO CALCULATION	

DUKE ENERGY FLORIDA

SCHEDULE 9
STATUS REPORT AND SPECIFICATIONS OF PROPOSED GENERATING FACILITIES
AS OF JANUARY 1, 2024

(1)	Plant Name and Unit Number:		**Undesignated CTs P3-P4**	
(2)	Capacity			
	a. Summer (MWs):		215	
	b. Winter (MWs):		235	
(3)	Technology Type:		COMBUSTION TURBINE	
(4)	Anticipated Construction Timing			
	a. Field construction start date:		7/2030	
	b. Commercial in-service date:		6/2033	(EXPECTED)
(5)	Fuel			
	a. Primary fuel:		NATURAL GAS	
	b. Alternate fuel:		DISTILLATE FUEL OIL	
(6)	Air Pollution Control Strategy:		Dry Low Nox Combustion	
(7)	Cooling Method:		N/A	
(8)	Total Site Area:		UNKNOWN	
(9)	Construction Status:		PLANNED	
(10)	Certification Status:		PLANNED	
(11)	Status with Federal Agencies:		PLANNED	
(12)	Projected Unit Performance Data			
	a. Planned Outage Factor (POF):		3.00	%
	b. Forced Outage Factor (FOF):		2.00	%
	c. Equivalent Availability Factor (EAF):		95.06	
	d. Resulting Capacity Factor (%):		1.9	%
	e. Average Net Operating Heat Rate (ANOHR):		10,487	BTU/kWh
(13)	Projected Unit Financial Data			
	a. Book Life (Years):		35	
	b. Total Installed Cost (In-service year $/kW):		1,428.6	
	c. Direct Construction Cost ($/kW):	($2024)	1,245.5	
	d. AFUDC Amount ($/kW):		181.7	
	e. Escalation ($/kW):		1.4	
	f. Fixed O&M ($/kW-yr):	($2024)	2.86	
	g. Variable O&M ($/MWh):	($2024)	9.03	
	h. K Factor:		NO CALCULATION	

NOTES
Total Installed Cost includes gas expansion, transmission interconnection and integration
$/kW values are based on Summer capacity
Fixed O&M cost does not include firm gas transportation costs

DUKE ENERGY FLORIDA

SCHEDULE 9
STATUS REPORT AND SPECIFICATIONS OF PROPOSED GENERATING FACILITIES
AS OF JANUARY 1, 2024

(1)	Plant Name and Unit Number:		**TBD**	
(2)	Capacity			
	a. Nameplate (MWac):		599.2	
	b. Summer Firm (MWac):		59.9	
	c. Winter Firm (MWac):		-	
(3)	Technology Type:		PHOTOVOLTAIC	
(4)	Anticipated Construction Timing			
	a. Field construction start date:		9/2032	
	b. Commercial in-service date:		7/2033	(EXPECTED)
(5)	Fuel			
	a. Primary fuel:		SOLAR	
	b. Alternate fuel:		N/A	
(6)	Air Pollution Control Strategy:		N/A	
(7)	Cooling Method:		N/A	
(8)	Total Site Area:		~500-600 ACRES PER SOLAR SITE (74.9 MW)	
(9)	Construction Status:		PLANNED	
(10)	Certification Status:			
(11)	Status with Federal Agencies:			
(12)	Projected Unit Performance Data			
	a. Planned Outage Factor (POF):		N/A %	
	b. Forced Outage Factor (FOF):		N/A %	
	c. Equivalent Availability Factor (EAF):		N/A %	
	d. Resulting Capacity Factor (%):		~27 %	
	e. Average Net Operating Heat Rate (ANOHR):		N/A BTU/Kwh	
(13)	Projected Unit Financial Data			
	a. Book Life (Years):		30	
	b. Total Installed Cost (In-service year $/Kw):		1,518.91	
	c. Direct Construction Cost ($/Kw ac):	($2024)		
	d. AFUDC Amount ($/Kw):			
	e. Escalation ($/Kw):			
	f. Fixed O&M ($/Kw dc-yr):	($2024)		
	g. Variable O&M ($/MWh):	($2024)	0.00	
	h. K Factor:		NO CALCULATION	

DUKE ENERGY FLORIDA

SCHEDULE 10
STATUS REPORT AND SPECIFICATIONS OF PROPOSED DIRECTLY ASSOCIATED TRANSMISSION LINES

MULE CREEK SOLAR

(1) POINT OF ORIGIN AND TERMINATION:	Ladybug Substation
(2) NUMBER OF LINES:	1
(3) RIGHT-OF-WAY:	Existing transmission line right-of-way
(4) LINE LENGTH:	0.1 miles
(5) VOLTAGE:	230 kV
(6) ANTICIPATED CONSTRUCTION TIMING:	1/1/2024
(7) ANTICIPATED CAPITAL INVESTMENT:	$5,536,000
(8) SUBSTATIONS:	Ladybug Substation
(9) PARTICIPATION WITH OTHER UTILITIES:	N/A

DUKE ENERGY FLORIDA

SCHEDULE 10

STATUS REPORT AND SPECIFICATIONS OF PROPOSED DIRECTLY ASSOCIATED TRANSMISSION LINES

WINQUEPIN SOLAR

(1) POINT OF ORIGIN AND TERMINATION:	Birch Switching Station
(2) NUMBER OF LINES:	1
(3) RIGHT-OF-WAY:	New transmission line right-of-way
(4) LINE LENGTH:	0.1 miles
(5) VOLTAGE:	230 kV
(6) ANTICIPATED CONSTRUCTION TIMING:	4/26/2024
(7) ANTICIPATED CAPITAL INVESTMENT:	$16,018,213
(8) SUBSTATIONS:	Birch Switching Station
(9) PARTICIPATION WITH OTHER UTILITIES:	N/A

DUKE ENERGY FLORIDA

SCHEDULE 10

STATUS REPORT AND SPECIFICATIONS OF PROPOSED DIRECTLY ASSOCIATED TRANSMISSION LINES

FALMOUTH SOLAR

(1) POINT OF ORIGIN AND TERMINATION:	Suwannee Substation
(2) NUMBER OF LINES:	1
(3) RIGHT-OF-WAY:	New transmission line right-of-way
(4) LINE LENGTH:	0.2 miles
(5) VOLTAGE:	115 kV
(6) ANTICIPATED CONSTRUCTION TIMING:	4/26/2024
(7) ANTICIPATED CAPITAL INVESTMENT:	$5,190,000
(8) SUBSTATIONS:	Suwannee Substation
(9) PARTICIPATION WITH OTHER UTILITIES:	N/A

DUKE ENERGY FLORIDA

SCHEDULE 10
STATUS REPORT AND SPECIFICATIONS OF PROPOSED DIRECTLY ASSOCIATED TRANSMISSION LINES

COUNTY LINE SOLAR

(1) POINT OF ORIGIN AND TERMINATION:	Ginnie Substation
(2) NUMBER OF LINES:	1
(3) RIGHT-OF-WAY:	Existing transmission line right-of-way
(4) LINE LENGTH:	0.1 miles
(5) VOLTAGE:	230 kV
(6) ANTICIPATED CONSTRUCTION TIMING:	12/31/2024
(7) ANTICIPATED CAPITAL INVESTMENT:	$3,532,625
(8) SUBSTATIONS:	Ginnie Substation
(9) PARTICIPATION WITH OTHER UTILITIES:	N/A

DUKE ENERGY FLORIDA

SCHEDULE 10

STATUS REPORT AND SPECIFICATIONS OF PROPOSED DIRECTLY ASSOCIATED TRANSMISSION LINES

SUNDANCE SOLAR

(1) POINT OF ORIGIN AND TERMINATION:	Birch Switching Station
(2) NUMBER OF LINES:	1
(3) RIGHT-OF-WAY:	New transmission line right-of-way
(4) LINE LENGTH:	0.5 miles
(5) VOLTAGE:	230 kV
(6) ANTICIPATED CONSTRUCTION TIMING:	3/1/2025
(7) ANTICIPATED CAPITAL INVESTMENT:	$5,540,000
(8) SUBSTATIONS:	Birch Switching Station
(9) PARTICIPATION WITH OTHER UTILITIES:	N/A

DUKE ENERGY FLORIDA

SCHEDULE 10
STATUS REPORT AND SPECIFICATIONS OF PROPOSED DIRECTLY ASSOCIATED TRANSMISSION LINES

BAILEY MILL SOLAR

(1) POINT OF ORIGIN AND TERMINATION:	Waukeenah Substation
(2) NUMBER OF LINES:	1
(3) RIGHT-OF-WAY:	New transmission line right-of-way
(4) LINE LENGTH:	0.1 miles
(5) VOLTAGE:	115 kV
(6) ANTICIPATED CONSTRUCTION TIMING:	7/3/2026
(7) ANTICIPATED CAPITAL INVESTMENT:	$11,060,000
(8) SUBSTATIONS:	Waukeenah Substation
(9) PARTICIPATION WITH OTHER UTILITIES:	N/A

DUKE ENERGY FLORIDA

SCHEDULE 10
STATUS REPORT AND SPECIFICATIONS OF PROPOSED DIRECTLY ASSOCIATED TRANSMISSION LINES

HALF MOON SOLAR

(1) POINT OF ORIGIN AND TERMINATION:	A new 230 kV Switching Station on the Central Florida to Holder 230 kV line, approximately 18 miles from Holder substation
(2) NUMBER OF LINES:	1
(3) RIGHT-OF-WAY:	Existing transmission line right-of-way
(4) LINE LENGTH:	0.1 miles
(5) VOLTAGE:	230 kV
(6) ANTICIPATED CONSTRUCTION TIMING:	12/1/2025
(7) ANTICIPATED CAPITAL INVESTMENT:	$28,167,740
(8) SUBSTATIONS:	A new 230 kV Switching Station on the Central Florida to Holder 230 kV line, approximately 18 miles from Holder substation
(9) PARTICIPATION WITH OTHER UTILITIES:	N/A

DUKE ENERGY FLORIDA

SCHEDULE 10
STATUS REPORT AND SPECIFICATIONS OF PROPOSED DIRECTLY ASSOCIATED TRANSMISSION LINES

RATTLER SOLAR

(1) POINT OF ORIGIN AND TERMINATION:	A greenfield four (4) position ring bus substation along the DEF Brooksville to Inverness 69 kV transmission line, proximate to the existing Nobleton Tap
(2) NUMBER OF LINES:	1
(3) RIGHT-OF-WAY:	New transmission line right-of-way
(4) LINE LENGTH:	1 mile
(5) VOLTAGE:	69 kV
(6) ANTICIPATED CONSTRUCTION TIMING:	11/1/2025
(7) ANTICIPATED CAPITAL INVESTMENT:	$22,337,000
(8) SUBSTATIONS:	A greenfield four (4) position ring bus substation along the DEF Brooksville to Inverness 69 kV transmission line, proximate to the existing Nobleton Tap
(9) PARTICIPATION WITH OTHER UTILITIES:	N/A

DUKE ENERGY FLORIDA

SCHEDULE 10

STATUS REPORT AND SPECIFICATIONS OF PROPOSED DIRECTLY ASSOCIATED TRANSMISSION LINES

OSPREY

(1) POINT OF ORIGIN AND TERMINATION:	Kathleen - Osprey
(2) NUMBER OF LINES:	1
(3) RIGHT-OF-WAY:	New transmission line right-of-way
(4) LINE LENGTH:	26.5 miles
(5) VOLTAGE:	230 kV
(6) ANTICIPATED CONSTRUCTION TIMING:	11/1/2024
(7) ANTICIPATED CAPITAL INVESTMENT:	$150,000,000
(8) SUBSTATIONS:	Kathleen, Osprey
(9) PARTICIPATION WITH OTHER UTILITIES:	N/A

INTEGRATED RESOURCE PLANNING OVERVIEW

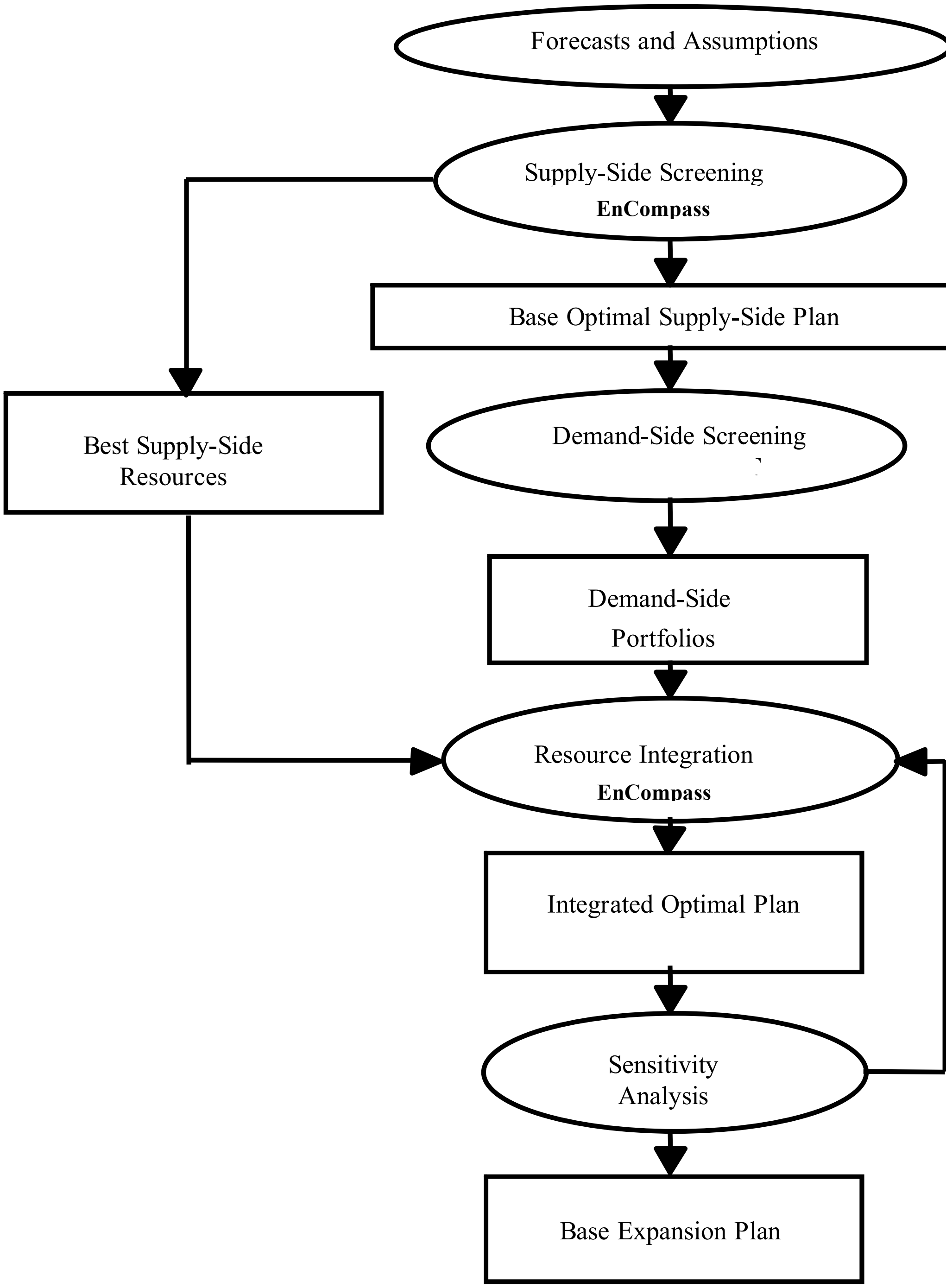
DEF employs an Integrated Resource Planning (IRP) process to determine the most cost-effective mix of supply- and demand-side alternatives that will reliably satisfy our customers' future demand and energy needs. DEF's IRP process incorporates state-of-the-art computer models used to evaluate a wide range of future generation alternatives and cost-effective conservation and dispatchable demand-side management programs on a consistent and integrated basis.

An overview of DEF's IRP Process is shown in Figure 3.1. The process begins with the development of various forecasts, including demand and energy, fuel prices, and economic assumptions. Future supply- and demand-side resource alternatives are identified, and extensive cost and operating data are collected to enable these to be modeled in detail. These alternatives are optimized together to determine the most cost-effective plan for DEF to pursue over the next ten years that meets the reliability criteria for our customers. The resulting ten-year plan, the Integrated Optimal Plan, is then tested under different relevant sensitivity scenarios to identify variances, if any, which would warrant reconsideration of any of the base plan assumptions. If the plan is judged robust and works within the corporate framework, it evolves as the Base Expansion Plan. This process is discussed in more detail in the following section titled "The Integrated Resource Planning (IRP) Process".

The IRP provides DEF with substantial guidance in assessing and optimizing the Company's overall resource mix on both the supply side and the demand side. When a decision supporting a significant resource commitment is being developed (e.g., plant construction, power purchase, DSM program implementation), the Company will move forward with directional guidance from the IRP and delve much further into the specific levels of examination required. This more detailed assessment will typically address very specific technical requirements and cost estimates, detailed corporate financial considerations, and the most current dynamics of the business and regulatory environments.

FIGURE 3.1

Integrated Resource Planning (IRP) Process Overview



THE INTEGRATED RESOURCE PLANNING (IRP) PROCESS

Forecasts and Assumptions

The evaluation of possible supply- and demand-side alternatives, and development of the optimal plan, is an integral part of the IRP process. These steps together comprise the integration process that begins with the development of forecasts and collection of input data. Base forecasts that reflect DEF's view of the most likely future scenario are developed. Additional future scenarios along with high and low forecasts may also be developed. Computer models used in the process are brought up to date to reflect this data, along with the latest operating parameters and maintenance schedules for DEF's existing generating units. This establishes a consistent starting point for all further analysis.

Reliability Criteria

Utilities require a margin of generating capacity above the firm demands of their customers in order to provide reliable service. Periodic scheduled outages are required to perform maintenance and inspections of generating plant equipment. At any given time during the year, some capacity may be out of service due to unanticipated equipment failures resulting in forced outages of generation units. Adequate reserve capacity must be available to accommodate these outages and to compensate for higher than projected peak demand due to forecast uncertainty and abnormal weather. In addition, some capacity must be available for operating reserves to maintain the balance between supply and demand on a moment-to-moment basis.

DEF plans its resources in a manner consistent with utility industry planning practices and employs both deterministic and probabilistic reliability criteria in the resource planning process. A Reserve Margin criterion is used as a deterministic measure of DEF's ability to meet its forecasted seasonal peak load with firm capacity. DEF plans its resources to satisfy a minimum 20% Reserve Margin criterion.

Loss of Load Probability (LOLP) is a probabilistic criterion that measures the probability that a company will be unable to meet its load throughout the year. While Reserve Margin considers the peak load and amount of installed resources, LOLP considers generating unit sizes, capacity mix, maintenance scheduling, unit availabilities, and capacity assistance available from other utilities. A standard probabilistic reliability threshold commonly used in the electric utility industry, and the criterion employed by DEF, is a maximum of one day in ten years loss of load probability.

DEF has based its resource planning on the use of dual reliability criteria since the early 1990s, a practice that has been accepted by the FPSC. DEF's resource portfolio is designed to satisfy the 20% Reserve Margin requirement and probabilistic analyses are periodically conducted to ensure that the one day in ten years LOLP criterion is also satisfied. By using both the Reserve Margin and LOLP planning criteria, DEF's resource portfolio is designed to have sufficient capacity available to meet customer peak demand, and to provide reliable generation service under expected load conditions. DEF has found that resource additions are typically triggered to meet the 20% Reserve Margin thresholds before LOLP becomes a factor.

Supply-Side Screening

Potential supply-side resources are screened to determine those that are the most cost-effective. Data used for the screening analysis is compiled from various industry sources and DEF's experiences. The wide range of resource options is pre-screened to set aside those that do not warrant a detailed cost-effectiveness analysis. Typical screening criteria are costs, fuel source, technology maturity, environmental parameters (e.g., emissions, possible climate impact), and overall resource feasibility.

Economic evaluation of generation alternatives is performed using the Capacity Expansion module of the EnCompass Power Planning Software licensed from Anchor Power Solutions. This optimization tool evaluates revenue requirements for specific resource plans generated from multiple combinations of future resource additions that meet system reliability criteria and other system constraints. Capacity expansion models are used to identify cost-effective system resources. However, additional modeling in a detailed production cost model is necessary to verify the resource selections with respect to cost, reliability, and environmental compliance as well as to conduct an overall assessment of the performance of the portfolio.

Demand-Side Screening

Like supply-side resources, the impacts of potential demand-side resources are also factored into the integrated resource plan. The projected MW and MWH impacts for demand-side management resources are based on the energy efficiency measures and energy management programs included in DEF's 2015 DSM Plan and meet the goals established by the FPSC in December 2019 (Docket 20190018-EG).

Resource Integration and the Integrated Optimal Plan

The cost-effective generation alternatives can then be optimized together with the demand-side portfolios developed in the screening process to formulate integrated optimal plans. The optimization program considers all possible future combinations of supply- and demand-side alternatives that meet the Company's reliability criteria in each year of the ten-year study period and reports those that provide both flexibility and reasonable revenue requirements (rates) for DEF's customers. Candidate base plans are then evaluated using the production cost module of EnCompass. Production cost models maintain full chronology and load requirements in all hours simulating the hour-to-hour operation of the system. This provides hourly modeling of the portfolio dispatch and provides insights into the detailed energy production cost of a given portfolio, the emissions profile and helps to identify potential issues with unit operation and reliability.

Developing the Base Expansion Plan

The integrated optimized plan that provides the lowest revenue requirements may then be further tested using sensitivity analysis, including High and Low Demand and Energy Forecasts (see Schedules 2 and 3). The economics of the plan may be evaluated under high and low forecast scenarios for fuel, load and financial assumptions, or any other sensitivities which the planner deems relevant. From the sensitivity assessment, the plan that is identified as achieving the best balance of flexibility and cost is then reviewed within the corporate framework to determine how the plan potentially impacts or is impacted by many other factors. If the plan is judged robust under this review, it would then be considered the Base Expansion Plan.

KEY CORPORATE FORECASTS

Load Forecast

The assumptions and methodology used to develop the base case load and energy forecast are described in Chapter 2 of this TYSP. The High and Low forecasts of load and energy were provided to Resource Planning to test the robustness of the base plan.

Fuel Price Forecast

The base case fuel price forecast was developed using short-term and long-term spot market price projections from industry-recognized sources. The base cost for coal is based on the existing contracts and spot market coal prices and transportation arrangements between DEF and its various suppliers. For the longer term, the prices are based on spot market forecasts reflective of expected market conditions. Oil and natural gas prices are estimated based on current and expected contracts and spot purchase arrangements as well as near-term and long-term market forecasts. Oil and natural gas commodity prices are driven primarily by open market forces of supply and demand. Natural gas firm transportation cost is determined primarily by pipeline tariff rates.

Financial Forecast

The key financial assumptions used in DEF's most recent planning studies were 47% debt and 53% equity capital structure, projected cost of debt of 6.0%, and an equity return of 10.1%. The assumptions resulted in a weighted average cost of capital of 8.17% and an after-tax discount rate of 7.45%.

TEN-YEAR SITE PLAN (TYSP) RESOURCE ADDITIONS

DEF's planned supply resource additions and changes are shown in Schedule 8 and are referred to as DEF's Base Expansion Plan. This plan includes a net addition of over 4,700 MW of solar PV generation with an expected equivalent summer firm capacity contribution of approximately 880 MW, 90 MW of firm storage added in 2027 and 430 MW of combustion turbine firm capacity added in years 2032 and 2033. The incorporation of the full firm capacity of the Osprey Energy Center takes place at the end of 2025. Between 2022 and 2027, DEF will add close to 400 MW of combined cycle capacity that results from projects focusing on increasing the fuel efficiency of the combined cycle generating units. DEF continues to consider market supply-side resource alternatives to enhance DEF's resource plan.

The incorporation of the IRA tax credits has helped offset projected cost increases for solar, batteries, and solar plus storage units. In DEF's most recent approved rate settlement (FPSC Docket No. 20210016-EI), DEF anticipates the retirement of the two remaining coal units at Crystal River (Crystal River units 4 and 5) in 2034. Solar PV and a mix of batteries and CTs will be the cost-effective generation to replace most of that energy in the 2034 timeframe. DEF's plan to construct Solar Plants continues following a steady path, including a total of 1350 MW in the years 2024 through 2027. From 2028 through 2030 two Solar plus Storage units will be added per year. A more aggressive addition of Solar resources will continue from 2028 through 2033, totaling an additional 2,925 MW over those 6 years. This provides a path to meeting this goal through a measured and paced approach to bringing the solar onto the system which recognizes the challenges of building and interconnecting solar projects, helps maintain reliability as solar penetration increases and maintains affordability in customer rates. As with other elements of the plan, DEF will update these projections as decision dates approach. DEF also continues to consider market supply-side resource alternatives to enhance DEF's resource plan.

DEF recognizes that, as solar penetration increases, including both DEF and customer-owned PV, the total dependable solar resource capability is influencing or shifting DEF's reserve planning focus later beyond the on-peak period. DEF is accounting for this planning shift by deriving reduced summer capacity values of planned PV installations starting in 2025. Refer to Page 3-2 for additional solar resource capacity values that are accounting for this change.

DEF's Base Expansion Plan projects the need for additional capacity with estimated in-service dates during the ten-year period from 2024 through 2033. The planned capacity additions, together with purchases from QFs, IOUs, and IPPs help the DEF system meet the energy requirements of its customer base. The capacity needs identified in this plan may be impacted by DEF's ability to extend or replace existing purchase power and QF contracts and to secure new renewable purchased power resources in their respective projected timeframes. The additions in the Base Expansion Plan depend, in part, on projected load growth, and obtaining all necessary state and federal permits under current schedules. Changes in these or other factors could impact DEF's Base Expansion Plan.

Through its ongoing planning process, DEF will continue to evaluate the timetables for all projected resource additions and assess alternatives for the future considering, among other things, projected load growth, fuel prices, lead times in the construction marketplace, project development timelines for new fuels and technologies, and environmental compliance considerations. The

Company will continue to examine the merits of new generation alternatives and adjust its resource plans accordingly to ensure optimal selection of resource additions based on the best information available.

RENEWABLE ENERGY

DEF continues to secure renewable energy from the following facilities listed by fuel type:

Purchases from Municipal Solid Waste Facilities:

Pasco County Resource Recovery (23 MW)
Pinellas County Resource Recovery (54.8 MW)
Dade County Resource Recovery (As Available)
Lake County Resource Recovery (As Available)
Lee County Resource Recovery (As Available)

Purchases from Waste Heat from Exothermic Processes:

PCS Phosphate (As Available)
Citrus World (As Available)

Solar Photovoltaic Facilities

DEF-owned Solar Generation (1185.75 MW)

- Osceola Solar Facility 3.8 MW
- Perry Solar Facility 5.1 MW
- Suwannee Solar Facility 8.8 MW
- Hamilton Solar Power Plant 74.9 MW
- Trenton Solar Power Plant 74.9 MW
- Lake Placid Solar Power Plant 45.0 MW
- St. Petersburg Pier Solar Power Plant 0.35 MW
- DeBary Solar Power Plant 74.5 MW
- Columbia Solar Power Plant 74.9 MW

Twin Rivers Solar Power Plant 74.9 MW
Santa Fe Solar Power Plant 74.9 MW
Duette Solar Power Plant 74.5 MW
Sandy Creek Solar Power Plant 74.9 MW
Fort Green Solar Power Plant 74.9 MW
Charlie Creek Solar Power Plant 74.9 MW
Bay Trail Solar Power Plant 74.9 MW
Bay Ranch Solar Power Plant 74.9 MW
Hardeetown Solar Power Plant 74.9 MW
High Springs Solar Power Plant 74.9 MW
Hildreth Solar Power Plant 74.9 MW

Customer-owned renewable generation under DEF's Net Metering Tariff (about 775 MW as of 12/31/23)

At this time, DEF is reviewing the potential for as-available purchased power contracts with third-party solar companies. In-service dates, however, are generally projected to be beyond 2025. As of December 31, 2023, DEF had over 5,100 MW of FERC jurisdictional solar projects in the DEF grid interconnection queue, representing over 69 active projects and 19 of those projects included DEF as the noted developer. DEF anticipates that additional projects developed by DEF as well as third parties will be added through the decade. Project ownership proportions may change over time based on specific project economics, development details, renewable energy incentives and other factors.

DEF continues to field inquiries from potential renewable suppliers and explore whether these potential QFs can provide project commitments and reliable capacity or energy consistent with FERC Rules and the FPSC Rules, 25-17.080 through 25-17.310. DEF will continue to submit renewable contracts in compliance with all policies as appropriate.

The development, construction, commissioning and initial operation of the solar projects at Perry, Osceola, Suwannee, Hamilton, Lake Placid, Trenton, DeBary, Columbia, Twin Rivers, Santa Fe, Duette, Bay Trail, Sandy Creek, Fort Green, Charlie Creek, the now commercial Bay Ranch, Hildreth, Hardeetown, and High Springs plants and under construction Mule Creek, Winquepin, Falmouth and County Line have provided DEF with valuable experience in siting, community engagement, contracting, constructing, operating, and integrating solar photovoltaic technology facilities on the power grid. DEF has worked with our communities on renewable and solar energy technology education, and our contractors to establish necessary standards for the construction and upkeep of utility grade facilities and to develop standards necessary to ensure the reliability of local distribution systems.

DEF is integrating voltage control in the transmission connected solar projects to enhance operational reliability and local transmission resiliency. In addition, DEF is incorporating the ability to place the solar facilities on Automatic Generation Control (AGC). This capability is preparing DEF for future scenarios where there is an excess of generation on the system and a need to utilize the solar resources to balance generation with demand. DEF is utilizing its operational experience and historic data from these solar resources to optimize the daily economic system dispatch, to quantify additional system flexibility needs to counteract the variability of solar generation and investigate potential fuel diversity contributions. The arrays for the solar plants that went in-service in 2023, Bay Ranch, Hardeetown, High Springs, and Hildreth, are shown in Figures 3.2, 3.3, 3.4, and 3.5 below.

FIGURE 3.2
Bay Ranch Solar Power Plant

FIGURE 3.3
Hardeetown Solar Power Plant

FIGURE 3.4
High Springs Solar Power Plant

FIGURE 3.5
Hildreth Power Plant

DEF's current forecast, supporting the Base Expansion Plan includes over 1,340 MW of DEF-owned solar PV to be under development over the next four years and approximately 4,700 MW over the ten-year planning horizon. As with all forecasts included here, the forecast relies heavily on the forward-looking price for this technology, the value rendered by this technology, and considerations to other emerging and conventional cost-effective alternatives, including the use of emerging battery storage technology.

BATTERY ENERGY STORAGE SYSTEMS

The final energy storage systems from DEF's 50 MW battery storage pilot program (Battery Storage Pilot) were placed in-service in 2023. This portfolio of projects may serve a variety of purposes including, but not limited to substation upgrade deferral, distribution line reconducting deferral, power reliability improvement, frequency regulation, Volt/VAR support, backup power, energy capture, and peak load shaving. The projects, max power output, and guaranteed energy storage for a minimum of ten years are provided in Table 3.3. Going forward, DEF will use the data gathered from the operation of these Pilot Program sites to evaluate the opportunities and uses of future DEF battery development. Integration and information sharing with the Duke Energy enterprise Emerging Technology Office will also allow real-world comparison with alternative technologies that may be available for commercial use in coming years.

Table 3.3
DEF Battery Energy Storage Pilot Program Projects Summary

Name	Max Power Output (MW)	Guaranteed Energy Storage (MWh)
Cape San Blas	5.5	14.3
Trenton	11.0	10.1
Micanopy	8.25	11.7
Jennings	5.5	5.5
John Hopkins Middle School	2.475	18.0
Lake Placid	17.275	34.0

DEF is currently developing a 100 MW / 200 MWH Battery Energy Storage System with a planned in-service date in 2027. The project will utilize lithium-ion energy storage and be located to maximize the Standalone Storage Investment Tax Credit (ITC) passed into law by the current administration. The expected increase of solar energy generation on the system provides a unique opportunity for energy storage assets to assist system integration of these intermittent resources and shift energy from lower system value periods to times with higher system value. This energy arbitrage will allow the cost of energy to be more predictably levelized and potentially partially reduces the need for peaking generation. New technologies and changing economics may allow acceleration of energy storage deployment in the future.

TECHNOLOGY AND INNOVATION

Duke Energy continues to evaluate new technology and innovations for potential application both in and beyond the ten-year plan window. Technologies under evaluation, but not yet included in the base expansion plan may be commercially or economically unproven, but Duke Energy and DEF are active in investigation and development of these technologies. At the Duke Energy enterprise level, engineers and specialists are involved in cooperative work with vendors and industry groups on supply-side technologies including wind generation, advanced battery development, hydrogen generation and combustion, and advanced nuclear. On the demand side, technologies including advanced demand response technologies such as commercial building pre-cooling, two-way water heater control, and smart appliance applications are being explored and evaluated. In addition, the company continues to explore intersections of grid and system operations with alternative generating technologies including distributed solar and storage and microgrid applications.

PLAN CONSIDERATIONS

Load Forecast

In general, higher-than-projected load growth would shift the need for new capacity to an earlier year and lower-than-projected load growth would delay the need for new resources. The Company's resource plan provides the flexibility to shift certain resources to earlier or later in-service dates should a significant change in projected customer demand begin to materialize. A specific discussion of DEF's review of load growth forecasts higher and lower than the base forecast can be found in the previous sections.

TRANSMISSION PLANNING

DEF's transmission planning assessment practices are developed to test the ability of the planned system to meet the reliability criteria as outlined in the FERC Form No. 715 filing, and to assure the system meets DEF, Florida Reliability Coordinating Council, Inc. (FRCC), and North American Electric Reliability Corporation (NERC) criteria. This involves the use of load flow and transient stability programs to model various contingency situations that may occur, and in determining if the system response meets the reliability criteria. In general, this involves running simulations for the loss of any single line, generator, or transformer. DEF runs this analysis for contingencies that may occur at system peak and off-peak load levels, under both summer and winter conditions. Additional studies are performed to determine the system response to credible, but less probable criteria. These studies include the loss of multiple generators, transmission lines, or combinations of each (some load loss is permissible under the more severe disturbances). These credible, but less probable scenarios are also evaluated at various load levels since some of the more severe situations occur at average or minimum load conditions. In particular, critical fault clearing times are typically the shortest (most severe) at minimum load conditions, with just a few large base load units supplying the system needs. As noted in the DEF reliability criteria, some remedial actions are allowed to reduce system loadings; in particular, sectionalizing is allowed to reduce loading on lower voltage lines for bulk system contingencies, but the risk to load on the sectionalized system must be reasonable (it would not be considered prudent to operate for long periods with a sectionalized system). In addition, the number of remedial action steps and the overall complexity of the scheme are evaluated to determine overall acceptability.

DEF presently uses the following reference documents to calculate and manage Available Transfer Capability (ATC), Total Transfer Capability (TTC) and Transmission Reliability Margin (TRM) for required transmission path postings on the Florida Open Access Same Time Information System (OASIS):

- http://www.oatioasis.com/FPC/FPCdocs/ATCID_Posted_Rev4.pdf
- http://www.oatioasis.com/FPC/FPCdocs/TRMID_4.pdf

DEF uses the following reference document to calculate and manage Capacity Benefit Margin (CBM):

- http://www.oatioasis.com/FPC/FPCdocs/CBMID_rev3.pdf

CHAPTER 4

ENVIRONMENTAL AND LAND USE INFORMATION

DUKE ENERGY.
FLORIDA

CHAPTER 4

ENVIRONMENTAL AND LAND USE INFORMATION

PREFERRED SITES

DEF's 2024 TYSP Preferred Sites include eight solar generations sites: the Mule Creek Solar Site, the Winquepin Solar Site, the Falmouth Solar Site, the County Line Solar Site, the Sundance Solar Site, the Bailey Mill Solar Site, the Half Moon Solar Site, and the Rattler Solar Site. These Preferred Sites are discussed below.

MULE CREEK SOLAR SITE

DEF has identified the Mule Creek Renewable Energy Center, a 74.9 MWac solar single-axis tracking PV project located in Bay County, Florida. Mule Creek is the third project constructed in Bay County. The site was used for pasture lands and is relatively flat with minimal sloping that will allow for the use of a tracking system. The point of interconnection is a new 230 kV breaker in DEF's existing Ladybug Switching Station and is connected via a short generation tie-line. All environmental surveys are complete. Solar is a now a permitted use on agriculturally zoned land in a local government comprehensive plan in the State of Florida. Special or Conditional use permits are no longer required. However, a Development Order (Final Site Plan approval) was required from Bay County. An Environmental Resource Permit (ERP) from the Florida Department of Environmental Protection (FDEP) was received in November 2022. There were no wetland impacts on site and there are no impacts to listed species. The project started construction in the spring of 2023. Construction is substantially complete, and the expected in-service date is March 2024.

FIGURE 4.1

Mule Creek Solar Project

Mule Creek	2500 Sandy Creek Rd
	Panama City, FL 32404

WINQUEPIN SOLAR SITE

DEF has identified the Winquepin Renewable Energy Center, a 74.9 MWac solar single-axis tracking PV project located in Madison County, Florida. The site is located on former agricultural and timber lands and is relatively flat with minimal sloping that will allow for the use of a tracking system. The point of interconnection is a new 230 kV, three terminal, three breaker switching station and is connected via a short generation tie-line. All environmental surveys are complete. Madison County approved the Final Site Plan and an ERP from FDEP was secured. There were no wetland impacts on site. State listed gopher tortoises were present onsite. The appropriate permit (Conservation/Relocation Permit) from the Florida Fish and Wildlife Conservation Commission (FWC) was secured. Tortoises have been relocated from the site. No additional listed species of concern were present. Construction began in the spring of 2023. Construction activities are substantially complete, and the expected in-service date is March 2024.

FIGURE 4.2

Winquepin Solar Project

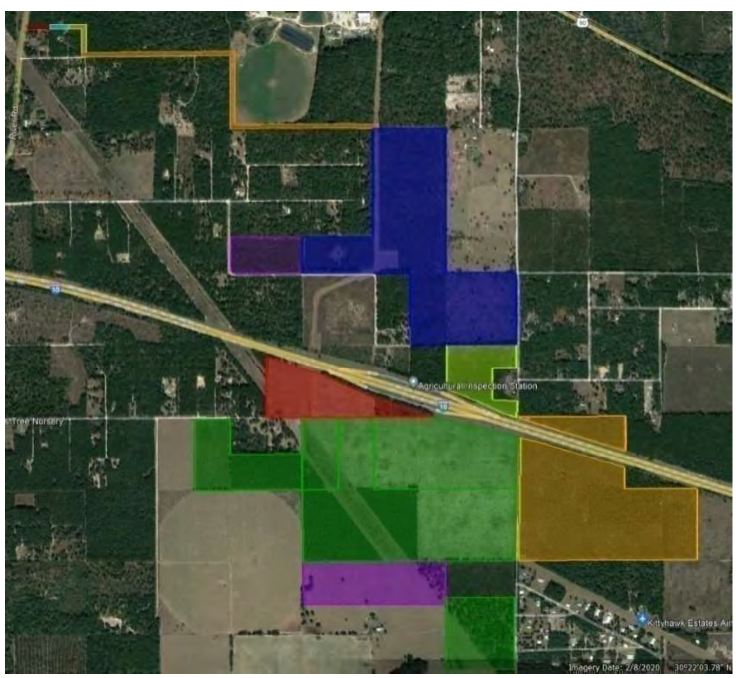
Winquepin	N. County Rd 53
	Madison, FL 32059

FALMOUTH SOLAR SITE

DEF has identified the Falmouth Renewable Energy Center, a 74.9 MWac solar single-axis tracking PV project located in Suwanee County, Florida. Falmouth will be the third project constructed in Suwannee County. The site was historically used as pasture and timber lands and is relatively flat with minimal sloping that will allow for the use of a tracking system. The point of interconnection will be a new 115 kV breaker in DEF's existing Suwanee Switching Station and will be connected via a 1.5-mile generation tie-line. All environmental surveys are complete. Suwannee County has provided Final Site Plan approval. The ERP was issued by FDEP on June 12, 2023. The two small wetlands on site, less than .5 acres total, were avoided thus there were no wetland impacts. The habitat assessment survey and subsequent species-specific surveys confirmed presence for the state-listed Southeastern American kestrel. Gopher tortoises were also present. FWC issued an Incidental Take Permit (ITP) for impacts to Southeastern American kestrel habitat and a Conservation/Relocation permit for gopher tortoises. Construction began in June of 2023. Construction is expected to complete by Q3 2024, with an expected in-service date of August 2024.

FIGURE 4.3

Falmouth Solar Project



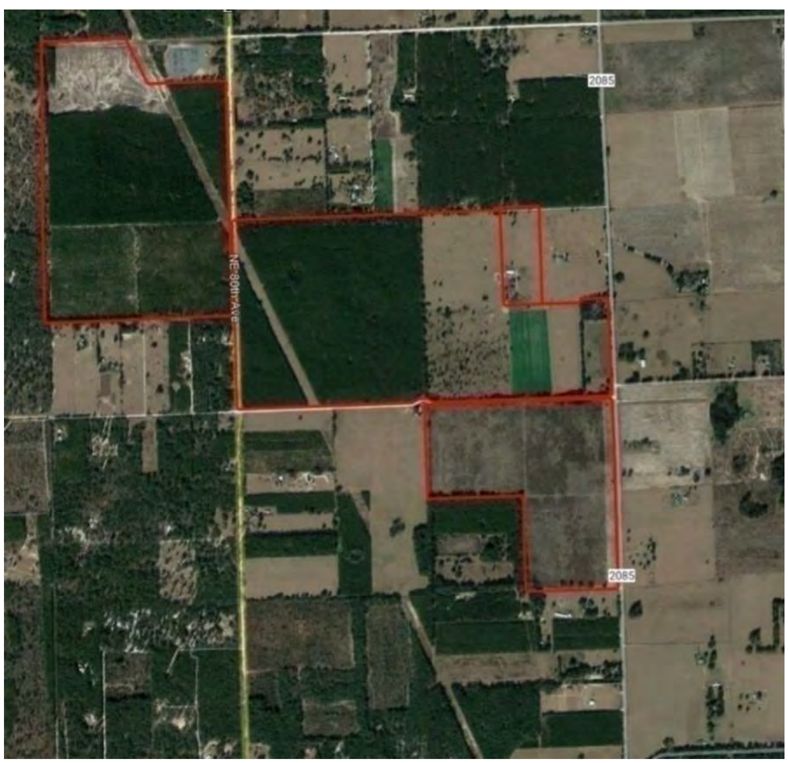
Falmouth	4431 River Rd
	Live Oak FL 32060

COUNTY LINE SOLAR SITE

DEF has identified the County Line Renewable Energy Center, a 74.9 MWac solar single-axis tracking PV project located in Gilchrist County, Florida. The site was used for timber and pasture land and is relatively flat with minimal sloping that will allow for the use of a tracking system. The point of interconnection will be a new 230 kV breaker in DEF's existing Ginnie Substation and will be connected via a short generation tie-line. Environmental surveys have been completed and confirmed the presence of state-listed Southeastern American kestrel and state-listed gopher tortoise. There are no wetlands onsite. Final Site Plan approval from Gilchrist County was received on November 14, 2023. FDEP issued the final ERP on July 25, 2023. There are no wetland impacts proposed. FWC issued an ITP for impacts to Southeastern American kestrel habitat and a Conservation/Relocation permit for gopher tortoises. All gopher tortoises have been relocated. Construction began in December 2023. The expected in-service date is October 2024.

FIGURE 4.4

County Line Solar Project



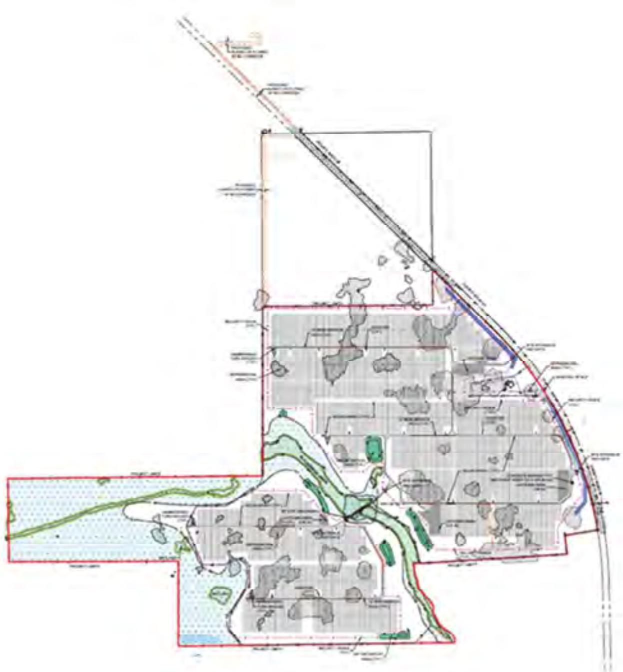
County Line	4960 NE 80th Blvd High Springs, FL 32643

SUNDANCE SOLAR SITE

DEF has identified the Sundance Renewable Energy Center, a 74.9 MWac solar single-axis tracking PV project located in Madison County, Florida. The site is located on former agricultural lands and is relatively flat with minimal sloping that will allow for the use of a tracking system. The point of interconnection will be a new breakered terminal in the 230 kV, three Birch switching station and will be connected via a mile generation tie-line. All environmental surveys are complete. Solar is a permitted use on agriculturally zoned land in a local government comprehensive plan in the State of Florida. Special or Conditional use permits are not required. However, a Site Plan approval is required from Madison County. An ERP from FDEP will also be required. DEF has applied for the ERP and expects to receive it early in spring 2024. There are several wetlands on site that will be avoided. State listed gopher tortoises were present onsite. The appropriate Relocation Permit from the FWC will be secured prior to construction. No additional listed species of concern were present. The project is expected to start construction in the spring of 2024, with an expected in-service date of early 2025.

FIGURE 4.5

Sundance Solar Project



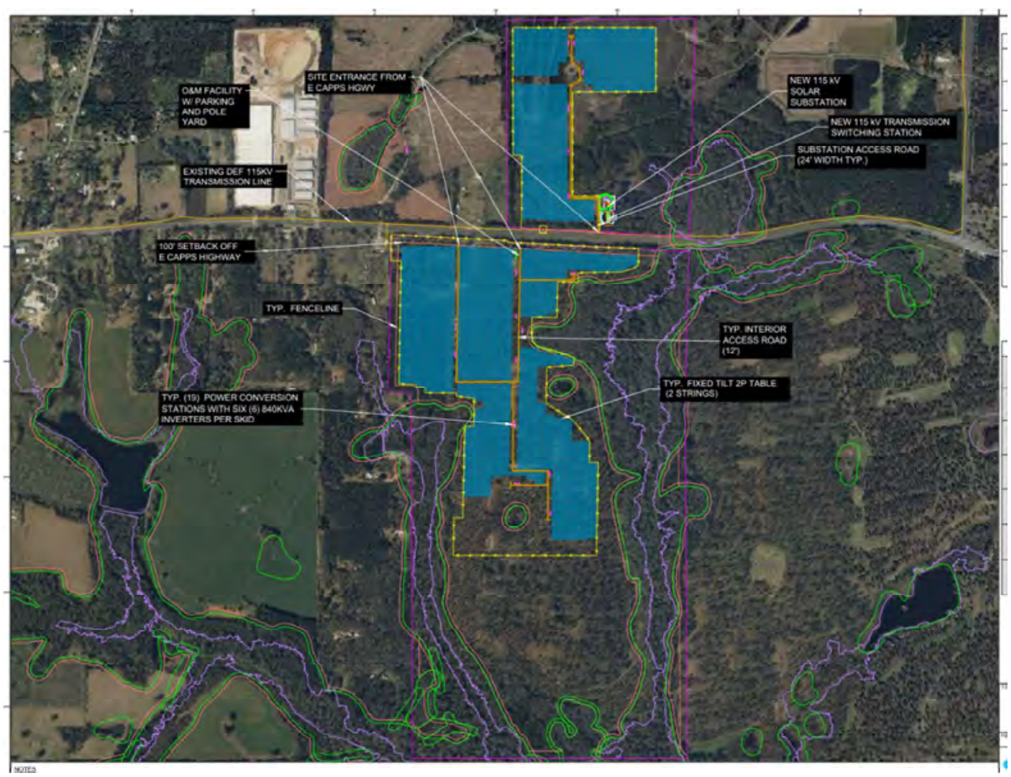
Sundance	16606 County Rd. 53
	Madison, FL 32059

BAILEY MILL SOLAR SITE

DEF has identified the Bailey Mill Renewable Energy Center, a 74.9 MWac solar Fixed tilt PV project located in Jefferson County, Florida. The site is located on timber and agricultural lands with some sloping that limits the use of a tracking system. The point of interconnection will be a new line tap on the Drifton to Waukeenah 115 kV line. All environmental surveys are complete. Solar is a permitted use on agriculturally zoned land in a local government comprehensive plan in the State of Florida. Special or Conditional use permits are not required. However, a Site Plan approval is required from Jefferson County. An ERP from FDEP will also be required. DEF intends to submit the ERP summer of 2024 and expects to receive it in late 2024. There are limited wetlands on site that will be avoided. State listed gopher tortoises were present onsite. The appropriate Relocation Permit from the FWC will be secured prior to construction. No additional listed species of concern were present. The project is expected to start construction in the spring of 2025, with an expected in-service date of December 2025.

FIGURE 4.6

Bailey Mill Solar Project



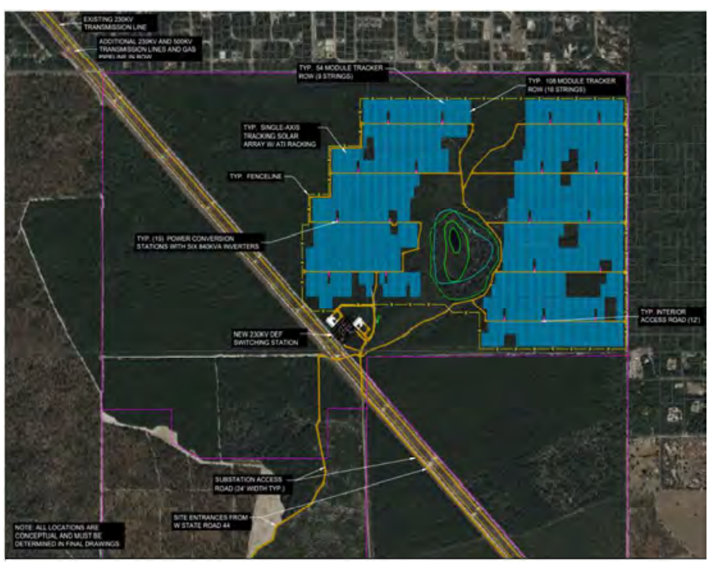
Bailey Mill	Jefferson County
	Zip Code 32344

HALF MOON SOLAR SITE

DEF has identified the Half Moon Renewable Energy Center, a 74.9 MWac solar single-axis tracking PV project located in Sumter County, Florida. The site is located on merchantable timber lands and is relatively flat with minimal sloping that will allow for the use of a tracking system. The point of interconnection will be a new 230 kV, three terminal, three breaker switching station and is connected via a short generation tie-line. All environmental surveys are complete. Solar is a permitted use on agriculturally zoned land in a local government comprehensive plan in the State of Florida. Special or Conditional use permits are not required. However, a Site Plan approval is required from Sumter County. An ERP from FDEP will also be required. DEF intends to submit the ERP summer of 2024 and expects to receive it in late 2024. There are limited wetlands on site that will be avoided. State listed gopher tortoises were present onsite. The appropriate Relocation Permit from the FWC will be secured prior to construction. The Florida Scrub Jay was shown in the area, but not present on site. Consultation with the FWC will be completed prior to the start of construction. The project is expected to start construction in the spring of 2025, with an expected in-service date of December 2025.

FIGURE 4.7

Half Moon Solar Project



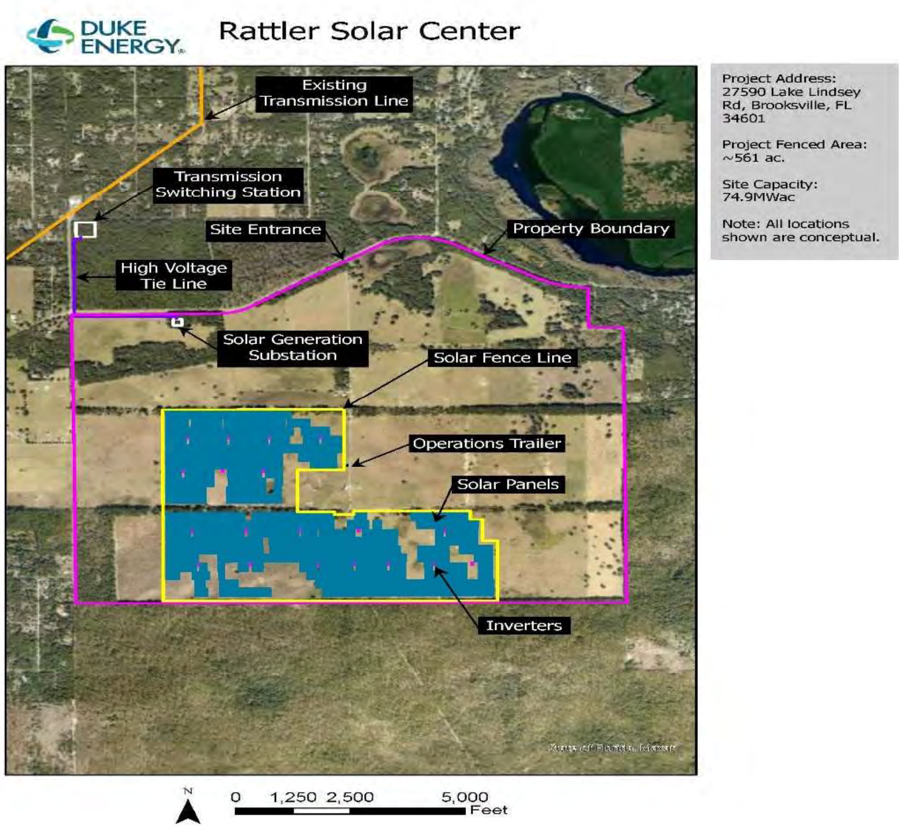
Half Moon	County:	Sumter	Latitude:	28.955619	Longitude:	-82.159585

RATTLER SOLAR SITE

DEF has identified the Rattler Renewable Energy Center, a 74.9 MWac solar single-axis tracking PV project located in Hernando County, Florida. The site is located on agricultural lands and is relatively flat with minimal sloping that will allow for the use of a tracking system. The point of interconnection will be a new 69 kV, four breaker switching station and is connected via a ~2-mile generation tie-line. All environmental surveys are complete. Solar is a permitted use on agriculturally zoned land in a local government comprehensive plan in the State of Florida. Special or Conditional use permits are not required. However, a Site Plan approval is required from Hernando County. An ERP from FDEP will also be required. DEF intends to submit the ERP summer of 2024 and expects to receive it in late 2024. There are limited wetlands on site that will be avoided. State listed gopher tortoises were present onsite. The appropriate permit Relocation Permit from the FWC will be secured prior to construction. The project is expected to start construction in the spring of 2025, with an expected in-service date of December 2025.

FIGURE 4.8

Rattler Solar Project



Progress Energy

JAMES A. MCGEE
ASSOCIATE GENERAL COUNSEL
PROGRESS ENERGY SERVICE COMPANY, LLC

April 1, 2005

VIA HAND DELIVERY

Ms. Blanca S. Bayó, Director
Division of the Commission Clerk
and Administrative Services
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, Florida 32399-0850

Re: Progress Energy's Ten-Year Site Plan as of December 31, 2004

Dear Ms. Bayó:

Enclosed for filing on behalf of Progress Energy Florida, Inc., are an original and fifteen copies of the subject Ten-Year Site Plan, as well as an additional ten copies for the other agencies and organizations on your distribution list.

Please acknowledge your receipt of the above filing on the enclosed copy of this letter and return to the undersigned. A 3½ inch diskette containing the above-referenced document in PDF format is also enclosed. Thank you for your assistance in this matter.

Very truly yours,

James A. McGee

JAM/scc
Enclosures

100 Central Avenue (33701) ▯ Post Office Box 14042 (33733) ▯ St. Petersburg, Florida
Phone: 727.820.5184 ▯ Fax: 727.820.5519 ▯ Email: james.mcgee@pgnmail.com

Progress Energy Florida
Ten-Year Site Plan

April 2005

2005-2014

Submitted to:
Florida Public Service Commission

Progress Energy

TABLE OF CONTENTS

LIST OF REQUIRED SCHEDULES

LIST OF
TABLES AND FIGURES

CODE IDENTIFICATION SHEET

Generating Unit Type

ST - Steam Turbine - Non-Nuclear
NP - Steam Power - Nuclear
GT - Gas Turbine (Combustion Turbine)
CC - Combined-cycle
SPP - Small Power Producer
COG - Cogeneration Facility

Fuel Type

NUC - Nuclear (Uranium)
NG - Natural Gas
RFO - No. 6 Residual Fuel Oil
DFO - No. 2 Distillate Fuel Oil
BIT - Bituminous Coal
MSW - Municipal Solid Waste
WH - Waste Heat
BIO - Biomass

Fuel Transportation

WA - Water
TK - Truck
RR - Railroad
PL - Pipeline
UN - Unknown

Future Generating Unit Status

A - Generating unit capability increased
FC - Existing generator planned for conversion to another fuel or energy source
P - Planned for installation but not authorized; not under construction
RP - Proposed for repowering or life extension
RT - Existing generator scheduled for retirement
T - Regulatory approval received but not under construction
U - Under construction, less than or equal to 50% complete
V - Under construction, more than 50% complete

This page intentionally left blank

INTRODUCTION

Section 186.801 of the Florida Statutes requires electric generating utilities to submit a Ten-Year Site Plan (TYSP) to the Florida Public Service Commission (FPSC). The TYSP includes historical and projected data pertaining to the utility's load and resource needs as well as a review of those needs. It is compiled in accordance with FPSC Rules 25-22.070 through 25.072, Florida Administrative Code.

Progress Energy Florida's (PEF's) TYSP is based on projections of long-term planning requirements that are dynamic in nature and subject to change. These planning documents should be used for general guidance concerning PEF's planning assumptions and projections, and should not be taken as an assurance that particular events discussed in the TYSP will materialize or that particular plans will be implemented. Information and projections pertinent to periods further out in time are inherently subject to greater uncertainty.

The TYSP document contains four chapters as described below:

CHAPTER 1

DESCRIPTION OF EXISTING FACILITIES

CHAPTER 2

FORECAST OF ELECTRICAL POWER DEMAND AND ENERGY CONSUMPTION

CHAPTER 3

FORECAST OF FACILITIES REQUIREMENTS

CHAPTER 4

ENVIRONMENTAL AND LAND USE INFORMATION

This page intentionally left blank

CHAPTER 1

DESCRIPTION OF EXISTING FACILITIES

Progress Energy

This page intentionally left blank

CHAPTER 1

DESCRIPTION OF EXISTING FACILITIES

EXISTING FACILITIES OVERVIEW

OWNERSHIP

Progress Energy Florida (PEF) is a wholly owned subsidiary of Progress Energy, Inc. (Progress Energy), a registered holding company under the Public Utility Holding Company Act (PUHCA) of 1935. Progress Energy and its subsidiaries, including PEF, are subject to the regulatory provisions of the PUHCA. Progress Energy is the parent company of PEF and certain other subsidiaries.

AREA OF SERVICE

PEF provided electric service during 2004 to an average of 1.5 million customers in Florida. Its service area covers approximately 20,000 square miles and includes the densely populated areas around Orlando, as well as the cities of St. Petersburg and Clearwater. PEF is interconnected with 21 municipal and 9 rural electric cooperative systems. PEF is subject to the rules and regulations of the Federal Energy Regulatory Commission (FERC) and the Florida Public Service Commission (FPSC). PEF's Service Area is shown in Figure 1.1.

TRANSMISSION/DISTRIBUTION

At December 31, 2004, PEF had approximately 5,000 circuit miles of transmission lines including 200 miles of 500 kV lines and about 1,500 miles of 230 kV lines, 22,000 circuit miles of overhead distribution conductor and 13,000 circuit miles of underground distribution cable. Distribution and transmission substations in service had a transformer capacity of approximately 45,000,000 kVA in 616 transformers. Distribution line transformers numbered approximately 365,000 with an aggregate capacity of approximately 18,000,000 kVA. A map of the Electric System can be found in Figure 1.2.

ENERGY MANAGEMENT

PEF customers participating in the company's residential Energy Management program are managing future growth and costs. Approximately 361,000 customers participated in the Energy

Management program at the end of the year, contributing about 725,000 kW of winter peak-shaving capacity for use during high load periods.

TOTAL CAPACITY RESOURCE

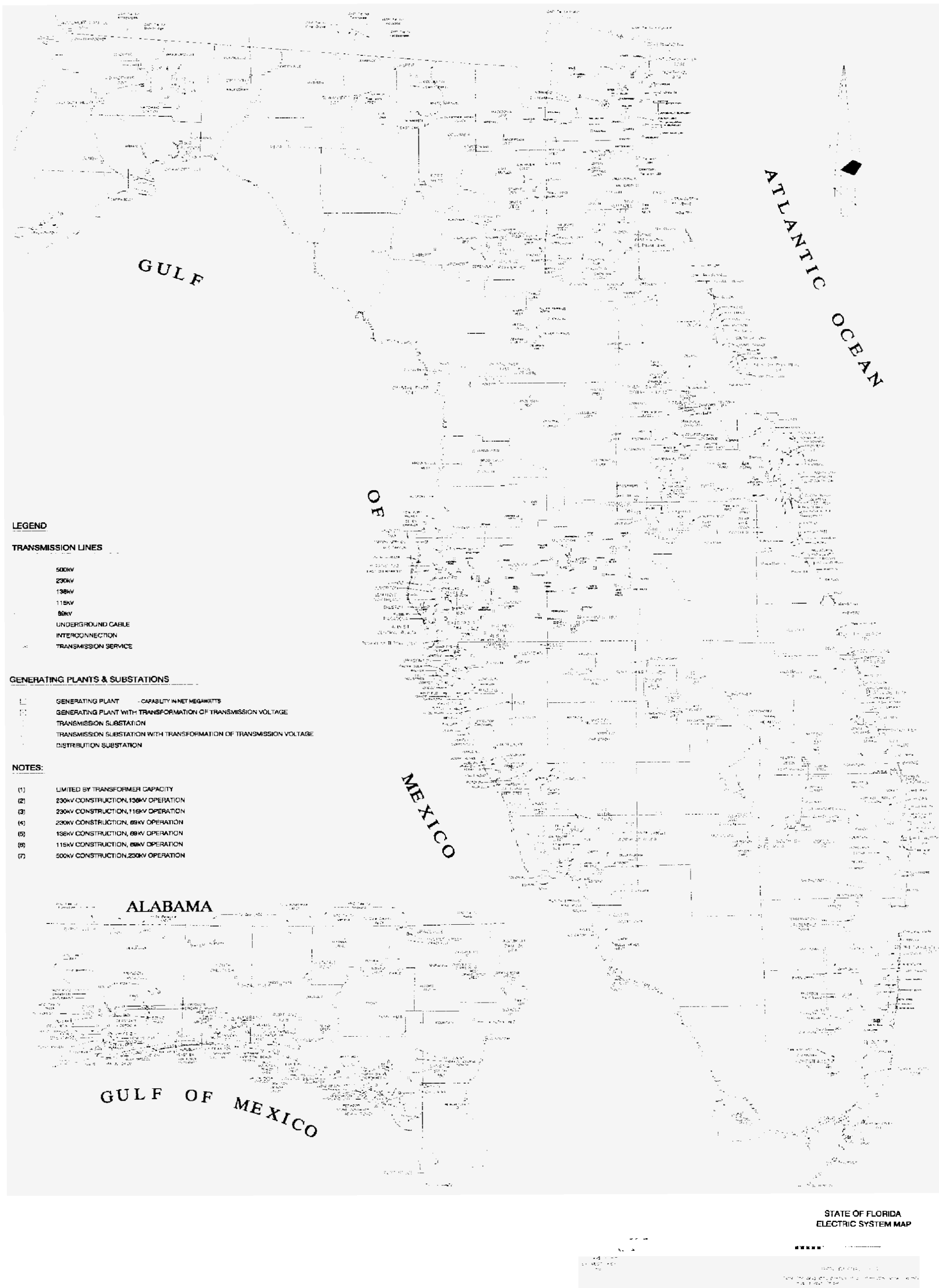
As of December 31, 2004, PEF had total summer capacity resources of approximately 9,769 MW consisting of installed capacity of 8,475 MW (excluding Crystal River 3 joint ownership) and 1,294 MW of firm purchased power. Additional information on PEF's existing generating resources is shown on Schedule 1 and Table 3.1.

FIGURE 1.1

PROGRESS ENERGY FLORIDA

Service Area Map

FIGURE 1.2
PROGRESS ENERGY FLORIDA
Electric System Map



PROGRESS ENERGY FLORIDA

SCHEDULE 1
EXISTING GENERATING FACILITIES
AS OF DECEMBER 31, 2004

(1) PLANT NAME	(2) UNIT NO.	(3) LOCATION (COUNTY)	(4) UNIT TYPE	(5) FUEL PRI.	(6) FUEL ALT.	(7) FUEL TRANSPORT PRI.	(8) FUEL TRANSPORT ALT.	(9) ALT. FUEL DAYS USE	(10) COM'L IN-SERVICE MO./YEAR	(11) EXPECTED RETIREMENT MO./YEAR	(12) GEN. MAX. NAMEPLATE KW	(13) NET CAPABILITY SUMMER MW	(14) NET CAPABILITY WINTER MW
STEAM													
ANCLOTE	1	PASCO	ST	RFO	NG	PL	PL		10/74		556,200	498	522
ANCLOTE	2	PASCO	ST	RFO	NG	PL	PL		10/78		556,200	495	522
BARTOW	1	PINELLAS	ST	RFO		WA			09/58		127,500	121	123
BARTOW	2	PINELLAS	ST	RFO		WA			08/61		127,500	119	121
BARTOW	3	PINELLAS	ST	RFO	NG	WA	PL		07/63		239,360	204	208
CRYSTAL RIVER	1	CITRUS	ST	BIT		WA,RR			10/66		440,550	379	383
CRYSTAL RIVER	2	CITRUS	ST	BIT		WA,RR			11/69		523,800	486	491
CRYSTAL RIVER	3 *	CITRUS	ST	NUC		TK			03/77		890,460	769	788
CRYSTAL RIVER	4	CITRUS	ST	BIT		WA,RR			12/82		739,260	720	735
CRYSTAL RIVER	5	CITRUS	ST	BIT		WA,RR			10/84		739,260	717	732
SUWANNEE RIVER	1	SUWANNEE	ST	RFO	NG	TK	PL		11/53		34,500	32	33
SUWANNEE RIVER	2	SUWANNEE	ST	RFO		TK			11/54		37,500	31	32
SUWANNEE RIVER	3	SUWANNEE	ST	RFO	NG	TK	PL		10/56		75,000	80	81
												4,651	**4,771**
COMBINED-CYCLE													
HINES ENERGY COMPLEX	1	POLK	CC	NG	DFO	PL	TK	6	04/99		546,550	482	529
HINES ENERGY COMPLEX	2	POLK	CC	NG	DFO	PL	TK	6	12/03		598,000	516	582
TIGER BAY	1	POLK	CC	NG		PL			08/97		278,223	207	223
												1,205	**1,334**
COMBUSTION TURBINE													
AVON PARK	P1	HIGHLANDS	GT	NG	DFO	PL	TK	3	12/68		33,790	26	32
AVON PARK	P2	HIGHLANDS	GT	DFO		TK			12/68		33,790	26	32
BARTOW	P1, P3	PINELLAS	GT	DFO		WA			5/72-6/72		111,400	92	106
BARTOW	P2	PINELLAS	GT	NG	DFO	PL	WA	8	06/72		55,700	46	53
BARTOW	P4	PINELLAS	GT	NG	DFO	PL	WA	8	06/72		55,700	49	60
BAYBORO	P1-P4	PINELLAS	GT	DFO		WA,TK			04/73		226,800	184	232
DEBARY	P1-P6	VOLUSIA	GT	DFO		TK			12/75-04/76		401,220	324	390
DEBARY	P7-P9	VOLUSIA	GT	NG	DFO	PL	TK	8	10/92		345,000	258	279
DEBARY	P10	VOLUSIA	GT	DFO		TK			10/92		115,000	85	93
HIGGINS	P1-P2	PINELLAS	GT	NG	DFO	PL	TK		03/69-04/69		67,580	54	64
HIGGINS	P3-P4	PINELLAS	GT	NG	DFO	PL	TK	1	12/70-01/71		85,850	68	70
INTERCESSION CITY	P1-P6	OSCEOLA	GT	DFO		PL,TK			05/74		340,200	294	366
INTERCESSION CITY	P7-P10	OSCEOLA	GT	NG	DFO	PL	PL,TK	5	10/93		460,000	352	376
INTERCESSION CITY	P11 **	OSCEOLA	GT	DFO		PL,TK			01/97		165,000	143	170
INTERCESSION CITY	P12-P14	OSCEOLA	GT	NG	DFO	PL	PL,TK	5	12/00		345,000	252	294
RIO PINAR	P1	ORANGE	GT	DFO		TK			11/70		19,290	13	16
SUWANNEE RIVER	P1	SUWANNEE	GT	NG	DFO	PL	TK	10	10/80		61,200	55	67
SUWANNEE RIVER	P2	SUWANNEE	GT	DFO		TK			10/80		61,200	54	67
SUWANNEE RIVER	P3	SUWANNEE	GT	NG	DFO	PL	TK	10	11/80		61,200	55	67
TURNER	P1-P2	VOLUSIA	GT	DFO		TK			10/70		38,580	26	32
TURNER	P3	VOLUSIA	GT	DFO		TK			08/74		71,200	65	82
TURNER	P4	VOLUSIA	GT	DFO		TK			08/74		71,200	63	80
UNIV. OF FLA.	P1	ALACHUA	GT	NG		PL			01/94		43,000	35	41
												2,619	**3,069**
											TOTAL RESOURCES (MW)	**8,475**	**9,174**

* REPRESENTS APPROXIMATELY 91.8% PEF OWNERSHIP OF UNIT
** SUMMER CAPABILITY (JUNE THROUGH SEPTEMBER) OWNED BY GEORGIA POWER COMPANY

This page intentionally left blank

CHAPTER 2

FORECAST OF ELECTRIC POWER DEMAND AND ENERGY CONSUMPTION

Progress Energy

This page intentionally left blank

CHAPTER 2

FORECAST OF ELECTRIC POWER DEMAND AND ENERGY CONSUMPTION

OVERVIEW

The following Schedules 2, 3 and 4 represent PEF's history and forecast of customers, energy sales (GWh), and peak demand (MW). High and low scenarios are also presented for sensitivity purposes.

The base case was developed using assumptions to predict a forecast with a 50/50 probability, or most likely scenario. The high and low scenarios, which have a 90/10 probability of occurrence or an 80 percent probability of an outcome falling between the high and low cases, employed a Monte Carlo simulation procedure that studied 1,000 possible outcomes of retail demand and energy.

PEF's customer growth is expected to average 1.7 percent between 2005 and 2014, less than the ten-year historical average of 2.2 percent. The ten-year historical growth rate falls to 2.0 percent when accounting for the creation of PEF's Seasonal Service Rate tariff, which artificially inflates customer growth figures. Slower population growth -- based on the latest projection from the University of Florida's Bureau of Economic and Business Research – and economic conditions less favorable for the housing/construction industry result in a lower base case customer projection when compared to the higher historical growth rate. This translates into lower projected energy and demand growth rates from historic rate levels.

Net energy for load (NEL), which had grown at an average of 3.3 percent between 1995 and 2004, is expected to increase by 2.5 percent per year from 2005-2014 in the base case, 2.8 percent in the high case and 2.2 percent in the low case. A lower contribution from the wholesale jurisdiction, which grew an average of 9.9 percent between 1995 and 2004, results in lower expected system growth going forward than the historic rate. Retail NEL, which grew at a

2.9 percent average rate historically, is expected to grow 2.6 percent over the next ten years. Wholesale NEL is expected to average just 1.4 percent between 2005 and 2014.

Summer net firm demand is expected to grow an average of 2.9 percent per year during the next ten years. This matches the average annual growth rate experienced throughout the last ten years. High and low summer growth rates for net firm demand are 3.2 percent and 2.6 percent per year, respectively. Winter net firm demand is projected to grow at 2.8 percent per year after having declined by 0.3 percent per year from 1995 to 2004. The low historical growth figure is driven by a mild weather peak day in 2004. High and low winter net firm demand growth rates are 3.1 percent and 2.5 percent, respectively.

Summer net firm retail demand is expected to grow an average of 2.4 percent per year during the next ten years; this compares to the 3.6 percent average annual growth rate experienced throughout the last ten years. High and low summer growth rates for net firm retail demand are 2.8 percent and 2.1 percent per year, respectively. Winter net firm retail demand is projected to grow at approximately 2.1 percent per year after having remained flat from 1995 to 2004. Again, a mild 2004 peak day causes this anomaly. High and low winter net firm retail demand growth rates are 2.5 percent and 1.8 percent, respectively.

ENERGY CONSUMPTION AND DEMAND FORECAST SCHEDULES

SCHEDULE	DESCRIPTION
2.1, 2.2 and 2.3	History and Forecast of Energy Consumption and Number of Customers by Customer Class
3.1.1, 3.1.2 and 3.1.3	History and Forecast of Base, High and Low Summer Peak Demand (MW)
3.2.1, 3.2.2 and 3.2.3	History and Forecast of Base, High, and Low Winter Peak Demand (MW)
3.3.1, 3.3.2 and 3.3.3	History and Forecast of Base, High and Low Annual Net Energy for Load (GWh)
4	Previous Year Actual and Two-Year Forecast of Peak Demand and Net Energy for Load by Month

PROGRESS ENERGY FLORIDA

SCHEDULE 2.1
HISTORY AND FORECAST OF ENERGY CONSUMPTION AND
NUMBER OF CUSTOMERS BY CUSTOMER CLASS

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
	RURAL AND RESIDENTIAL					COMMERCIAL		
YEAR	PEF POPULATION	MEMBERS PER HOUSEHOLD	GWh	AVERAGE NO. OF CUSTOMERS	AVERAGE KWh CONSUMPTION PER CUSTOMER	GWh	AVERAGE NO. OF CUSTOMERS	AVERAGE KWh CONSUMPTION PER CUSTOMER
1995	2,801,105	2.491	14,938	1,124,679	13,282	8,612	126,189	68,247
1996	2,847,802	2.494	15,481	1,141,671	13,560	8,848	129,440	68,356
1997	2,895,266	2.495	15,080	1,160,611	12,993	9,257	132,504	69,862
1998	2,959,509	2.502	16,526	1,182,786	13,972	9,999	136,345	73,336
1999	3,047,293	2.511	16,245	1,213,470	13,387	10,327	140,897	73,295
2000	3,044,449	2.467	17,116	1,234,286	13,867	10,813	143,475	75,368
2001	3,141,867	2.465	17,604	1,274,672	13,810	11,061	146,983	75,251
2002	3,207,661	2.465	18,754	1,301,515	14,409	11,420	150,577	75,842
2003	3,286,782	2.468	19,429	1,331,914	14,587	11,553	154,294	74,876
2004	3,348,630	2.454	19,347	1,364,677	14,177	11,734	158,780	73,898
2005	3,397,566	2.449	20,069	1,387,564	14,464	12,521	161,148	77,701
2006	3,457,712	2.447	20,602	1,412,969	14,581	12,998	164,319	79,101
2007	3,517,107	2.445	21,139	1,438,524	14,695	13,440	167,509	80,235
2008	3,581,336	2.446	21,669	1,463,871	14,803	13,861	170,672	81,212
2009	3,645,405	2.448	22,201	1,489,119	14,909	14,296	173,820	82,244
2010	3,702,998	2.446	22,742	1,514,200	15,019	14,736	176,945	83,281
2011	3,757,423	2.441	23,288	1,539,080	15,131	15,196	180,043	84,404
2012	3,809,526	2.436	23,837	1,563,793	15,243	15,663	183,119	85,533
2013	3,853,021	2.426	24,394	1,588,391	15,358	16,135	186,180	86,662
2014	3,891,403	2.413	24,959	1,612,925	15,475	16,613	189,232	87,790

PROGRESS ENERGY FLORIDA

SCHEDULE 2.2
HISTORY AND FORECAST OF ENERGY CONSUMPTION AND
NUMBER OF CUSTOMERS BY CUSTOMER CLASS

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
	INDUSTRIAL						
YEAR	GWh	AVERAGE NO. OF CUSTOMERS	AVERAGE KWh CONSUMPTION PER CUSTOMER	RAILROADS AND RAILWAYS GWh	STREET & HIGHWAY LIGHTING GWh	OTHER SALES TO PUBLIC AUTHORITIES GWh	TOTAL SALES TO ULTIMATE CONSUMERS GWh
1995	3,864	3,143	1,229,399	0	27	2,058	29,499
1996	4,224	2,927	1,443,116	0	26	2,205	30,784
1997	4,188	2,830	1,479,859	0	27	2,299	30,851
1998	4,375	2,707	1,616,180	0	27	2,459	33,386
1999	4,334	2,629	1,648,536	0	27	2,509	33,442
2000	4,249	2,535	1,676,134	0	28	2,626	34,832
2001	3,872	2,551	1,517,836	0	28	2,698	35,263
2002	3,835	2,535	1,512,821	0	28	2,822	36,859
2003	4,001	2,643	1,513,810	0	29	2,946	37,957
2004	4,069	2,733	1,488,840	0	28	3,016	38,193
2005	4,403	2,813	1,565,205	0	28	3,264	40,286
2006	4,485	2,813	1,594,218	0	28	3,384	41,497
2007	4,561	2,813	1,621,534	0	28	3,505	42,673
2008	4,600	2,813	1,635,285	0	28	3,617	43,775
2009	4,638	2,813	1,648,721	0	28	3,729	44,892
2010	4,670	2,813	1,660,209	0	28	3,843	46,020
2011	4,701	2,813	1,671,100	0	28	3,966	47,180
2012	4,731	2,813	1,681,991	0	28	4,095	48,354
2013	4,757	2,813	1,691,157	0	28	4,221	49,535
2014	4,780	2,813	1,699,167	0	28	4,344	50,724

PROGRESS ENERGY FLORIDA

SCHEDULE 2.3
HISTORY AND FORECAST OF ENERGY CONSUMPTION AND
NUMBER OF CUSTOMERS BY CUSTOMER CLASS

(1) YEAR	(2) SALES FOR RESALE GWh	(3) UTILITY USE & LOSSES GWh	(4) NET ENERGY FOR LOAD GWh	(5) OTHER CUSTOMERS (AVERAGE NO.)	(6) TOTAL NO. OF CUSTOMERS
1995	1,846	2,322	33,667	17,774	1,271,785
1996	2,089	1,842	34,715	18,035	1,292,073
1997	1,758	1,996	34,605	18,562	1,314,507
1998	2,340	2,037	37,763	19,013	1,340,851
1999	3,267	2,451	39,160	19,601	1,376,597
2000	3,732	2,678	41,242	20,004	1,400,299
2001	3,839	1,830	40,933	20,752	1,444,958
2002	3,173	2,534	42,567	21,156	1,475,783
2003	3,359	2,595	43,911	21,665	1,510,516
2004	4,301	2,773	45,268	22,437	1,548,627
2005	4,572	2,773	47,630	22,922	1,574,447
2006	3,518	2,885	47,900	23,499	1,603,600
2007	3,753	2,945	49,372	24,079	1,632,925
2008	3,748	3,044	50,567	24,660	1,662,016
2009	3,674	3,082	51,648	25,241	1,690,993
2010	4,275	3,246	53,541	25,822	1,719,780
2011	4,427	3,275	54,882	26,403	1,748,339
2012	4,554	3,354	56,263	26,984	1,776,709
2013	4,706	3,435	57,676	27,565	1,804,949
2014	5,242	3,555	59,520	28,144	1,833,114

PROGRESS ENERGY FLORIDA

SCHEDULE 3.1.1
HISTORY AND FORECAST OF SUMMER PEAK DEMAND (MW)
BASE CASE

(1) YEAR	(2) TOTAL	(3) WHOLESALE	(4) RETAIL	(5) INTERRUPTIBLE	(6) RESIDENTIAL LOAD MANAGEMENT	(7) RESIDENTIAL CONSERVATION	(8) COMM. / IND. LOAD MANAGEMENT	(9) COMM. / IND. CONSERVATION	(OTH) OTHER DEMAND REDUCTIONS	(10) NET FIRM DEMAND
1995	7,523	959	6,564	269	503	64	40	106	160	6,381
1996	7,470	828	6,642	309	565	69	41	120	167	6,199
1997	7,786	874	6,912	288	555	78	41	131	170	6,523
1998	8,367	943	7,424	291	438	97	42	142	182	7,175
1999	9,039	1,326	7,713	292	505	113	45	153	183	7,747
2000	8,911	1,319	7,592	277	455	127	48	155	75	7,774
2001	8,841	1,117	7,724	283	414	139	54	156	75	7,720
2002	9,421	1,203	8,218	305	390	153	43	159	75	8,296
2003	8,886	887	7,999	300	347	172	44	164	75	7,785
2004	9,554	1,071	8,483	531	283	188	37	166	75	8,274
2005	9,547	948	8,599	633	258	203	38	167	75	8,172
2006	9,808	993	8,815	420	228	214	39	169	75	8,663
2007	10,085	1,063	9,022	417	202	223	40	171	75	8,957
2008	10,298	1,093	9,205	413	179	232	41	172	75	9,186
2009	10,452	1,063	9,388	409	158	241	42	174	75	9,353
2010	10,802	1,213	9,589	400	140	250	43	176	75	9,719
2011	11,007	1,217	9,790	401	124	259	45	177	75	9,926
2012	11,218	1,230	9,988	402	109	269	46	179	75	10,138
2013	11,436	1,251	10,185	403	97	279	47	180	75	10,355
2014	11,651	1,269	10,382	404	86	289	48	182	75	10,567

Historical Values (1995 - 2004):

Col. (2) = recorded peak + implemented load control + residential and commercial/industrial conservation and customer-owned self-service cogeneration.

Cols. (5) - (9) = cumulative conservation and load control capabilities at peak. Col. (8) includes commercial load management and standby generation.

Col. (OTH) = Residential Heat Works load control, voltage reduction and customer-owned self-service cogeneration.

Col. (10) = (2) - (5) - (6) - (7) - (8) - (9) - (OTH).

Projected Values (2005 - 2014):

Cols. (2) - (4) = forecasted peak without load control, conservation, and customer-owned self-service cogeneration.

Cols. (5) - (9) = cumulative conservation and load control capabilities at peak. Col. (8) includes commercial load management and standby generation.

Col. (OTH) = customer-owned self-service cogeneration.

Col. (10) = (2) - (5) - (6) - (7) - (8) - (9) - (OTH).

PROGRESS ENERGY FLORIDA

SCHEDULE 3.1.2
HISTORY AND FORECAST OF SUMMER PEAK DEMAND (MW)
HIGH LOAD FORECAST

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(OTH)	(10)
YEAR	TOTAL	WHOLESALE	RETAIL	INTERRUPTIBLE	RESIDENTIAL LOAD MANAGEMENT	RESIDENTIAL CONSERVATION	COMM. / IND. LOAD MANAGEMENT	COMM. / IND. CONSERVATION	OTHER DEMAND REDUCTIONS	NET FIRM DEMAND
1995	7,523	959	6,564	269	503	64	40	106	160	6,381
1996	7,470	828	6,642	309	565	69	41	120	167	6,199
1997	7,786	874	6,912	288	555	78	41	131	170	6,523
1998	8,367	943	7,424	291	438	97	42	142	182	7,175
1999	9,039	1,326	7,713	292	505	113	45	153	183	7,747
2000	8,911	1,319	7,592	277	455	127	48	155	75	7,774
2001	8,841	1,117	7,724	283	414	139	54	156	75	7,720
2002	9,421	1,203	8,218	305	390	153	43	159	75	8,296
2003	8,886	887	7,999	300	347	172	44	164	75	7,785
2004	9,554	1,071	8,483	531	283	188	37	166	75	8,274
2005	9,711	948	8,763	633	258	203	38	167	75	8,336
2006	9,990	993	8,997	420	228	214	39	169	75	8,844
2007	10,298	1,063	9,236	417	202	223	40	171	75	9,170
2008	10,542	1,093	9,449	413	179	232	41	172	75	9,430
2009	10,709	1,063	9,645	409	158	241	42	174	75	9,609
2010	11,077	1,213	9,865	400	140	250	43	176	75	9,994
2011	11,314	1,217	10,096	401	124	259	45	177	75	10,232
2012	11,591	1,230	10,361	402	109	269	46	179	75	10,510
2013	11,852	1,251	10,601	403	97	279	47	180	75	10,771
2014	12,136	1,269	10,866	404	86	289	48	182	75	11,052

Historical Values (1995 - 2004):

Col. (2) = recorded peak + implemented load control + residential and commercial/industrial conservation and customer-owned self-service cogeneration.

Cols. (5) - (9) = cumulative conservation and load control capabilities at peak. Col. (8) includes commercial load management and standby generation.

Col. (OTH) = Residential Heat Works load control, voltage reduction and customer-owned self-service cogeneration.

Col. (10) = (2) - (5) - (6) - (7) - (8) - (9) - (OTH).

Projected Values (2005 - 2014):

Cols. (2) - (4) = forecasted peak without load control, conservation, and customer-owned self-service cogeneration.

Cols. (5) - (9) = cumulative conservation and load control capabilities at peak. Col. (8) includes commercial load management and standby generation.

Col. (OTH) = customer-owned self-service cogeneration.

Col. (10) = (2) - (5) - (6) - (7) - (8) - (9) - (OTH).

PROGRESS ENERGY FLORIDA

SCHEDULE 3.1.3
HISTORY AND FORECAST OF SUMMER PEAK DEMAND (MW)
LOW LOAD FORECAST

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(OTH)	(10)
YEAR	TOTAL	WHOLESALE	RETAIL	INTERRUPTIBLE	RESIDENTIAL LOAD MANAGEMENT	RESIDENTIAL CONSERVATION	COMM. / IND. LOAD MANAGEMENT	COMM. / IND. CONSERVATION	OTHER DEMAND REDUCTIONS	NET FIRM DEMAND
1995	7,523	959	6,564	269	503	64	40	106	160	6,381
1996	7,470	828	6,642	309	565	69	41	120	167	6,199
1997	7,786	874	6,912	288	555	78	41	131	170	6,523
1998	8,367	943	7,424	291	438	97	42	142	182	7,175
1999	9,039	1,326	7,713	292	505	113	45	153	183	7,747
2000	8,911	1,319	7,592	277	455	127	48	155	75	7,774
2001	8,841	1,117	7,724	283	414	139	54	156	75	7,720
2002	9,421	1,203	8,218	305	390	153	43	159	75	8,296
2003	8,886	887	7,999	300	347	172	44	164	75	7,785
2004	9,554	1,071	8,483	531	283	188	37	166	75	8,274
2005	9,382	948	8,434	633	258	203	38	167	75	8,007
2006	9,637	993	8,644	420	228	214	39	169	75	8,491
2007	9,889	1,063	8,827	417	202	223	40	171	75	8,761
2008	10,091	1,093	8,998	413	179	232	41	172	75	8,979
2009	10,202	1,063	9,138	409	158	241	42	174	75	9,102
2010	10,518	1,213	9,306	400	140	250	43	176	75	9,435
2011	10,670	1,217	9,452	401	124	259	45	177	75	9,588
2012	10,854	1,230	9,624	402	109	269	46	179	75	9,773
2013	11,043	1,251	9,792	403	97	279	47	180	75	9,962
2014	11,192	1,269	9,922	404	86	289	48	182	75	10,108

Historical Values (1995 - 2004):
Col. (2) = recorded peak + implemented load control + residential and commercial/industrial conservation and customer-owned self-service cogeneration.
Cols. (5) - (9) = cumulative conservation and load control capabilities at peak. Col. (8) includes commercial load management and standby generation.
Col. (OTH) = Residential Heat Works load control, voltage reduction and customer-owned self-service cogeneration.
Col. (10) = (2) - (5) - (6) - (7) - (8) - (9) - (OTH).
Projected Values (2005 - 2014):
Cols. (2) - (4) = forecasted peak without load control, conservation, and customer-owned self-service cogeneration.
Cols. (5) - (9) = cumulative conservation and load control capabilities at peak. Col. (8) includes commercial load management and standby generation.
Col. (OTH) = customer-owned self-service cogeneration.
Col. (10) = (2) - (5) - (6) - (7) - (8) - (9) - (OTH).

PROGRESS ENERGY FLORIDA

SCHEDULE 3.2.1
HISTORY AND FORECAST OF WINTER PEAK DEMAND (MW)
BASE CASE

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(OTH)	(10)
YEAR	TOTAL	WHOLESALE	RETAIL	INTERRUPTIBLE	RESIDENTIAL LOAD MANAGEMENT	RESIDENTIAL CONSERVATION	COMM. / IND. LOAD MANAGEMENT	COMM. / IND. CONSERVATION	OTHER DEMAND REDUCTIONS	NET FIRM DEMAND
1994/95	9,084	1,145	7,939	281	997	101	5	75	131	7,494
1995/96	10,562	1,489	9,073	255	1,156	106	15	95	201	8,734
1996/97	8,486	1,235	7,251	290	917	133	16	104	190	6,836
1997/98	7,752	941	6,811	318	663	164	17	112	168	6,310
1998/99	10,473	1,741	8,732	305	874	196	18	117	187	8,776
1999/00	10,040	1,728	8,312	225	849	229	20	119	182	8,416
2000/01	11,450	1,984	9,466	255	809	254	29	120	194	9,789
2001/02	10,676	1,624	9,052	285	770	278	24	121	188	9,010
2002/03	11,555	1,538	10,017	271	768	313	27	124	200	9,852
2003/04	9,290	1,167	8,123	498	761	343	24	125	218	7,321
2004/05	11,207	1,771	9,436	793	725	371	26	125	252	8,914
2005/06	11,144	1,502	9,642	432	696	405	28	127	255	9,200
2006/07	11,654	1,807	9,847	433	671	429	30	128	259	9,704
2007/08	11,869	1,825	10,045	428	649	453	31	130	262	9,915
2008/09	12,098	1,856	10,242	424	631	479	33	132	266	10,133
2009/10	12,486	2,049	10,438	415	615	506	35	133	269	10,513
2010/11	12,739	2,106	10,633	417	603	534	37	135	272	10,742
2011/12	12,991	2,165	10,826	418	593	566	38	136	276	10,964
2012/13	13,248	2,230	11,018	419	586	597	40	138	279	11,189
2013/14	13,504	2,295	11,209	420	581	628	42	139	282	11,412

Historical Values (1995 - 2004):

Col. (2) = recorded peak + implemented load control + residential and commercial/industrial conservation and customer-owned self-service cogeneration.

Cols. (5) - (9) = cumulative conservation and load control capabilities at peak. Col. (8) includes commercial load management and standby generation.

Col. (OTH) = Residential Heat Works load control, voltage reduction and customer-owned self-service cogeneration.

Col. (10) = (2) - (5) - (6) - (7) - (8) - (9) - (OTH).

Projected Values (2005 - 2014):

Cols. (2) - (4) = forecasted peak without load control, conservation, and customer-owned self-service cogeneration.

Cols. (5) - (9) = cumulative conservation and load control capabilities at peak. Col. (8) includes commercial load management and standby generation.

Col. (OTH) = voltage reduction and customer-owned self-service cogeneration.

Col. (10) = (2) - (5) - (6) - (7) - (8) - (9) - (OTH).

PROGRESS ENERGY FLORIDA

SCHEDULE 3.2.2
HISTORY AND FORECAST OF WINTER PEAK DEMAND (MW)
HIGH LOAD FORECAST

(1) YEAR	(2) TOTAL	(3) WHOLESALE	(4) RETAIL	(5) INTERRUPTIBLE	(6) RESIDENTIAL LOAD MANAGEMENT	(7) RESIDENTIAL CONSERVATION	(8) COMM. / IND. LOAD MANAGEMENT	(9) COMM. / IND. CONSERVATION	(OTH) OTHER DEMAND REDUCTIONS	(10) NET FIRM DEMAND
1994/95	9,084	1,145	7,939	281	997	101	5	75	131	7,494
1995/96	10,562	1,489	9,073	255	1,156	106	15	95	201	8,734
1996/97	8,486	1,235	7,251	290	917	133	16	104	190	6,836
1997/98	7,752	941	6,811	318	663	164	17	112	168	6,310
1998/99	10,473	1,741	8,732	305	874	196	18	117	187	8,776
1999/00	10,040	1,728	8,312	225	849	229	20	119	182	8,416
2000/01	11,450	1,984	9,466	255	809	254	29	120	194	9,789
2001/02	10,676	1,624	9,052	285	770	278	24	121	188	9,010
2002/03	11,555	1,538	10,017	271	768	313	27	124	200	9,852
2003/04	9,290	1,167	8,123	498	761	343	24	125	218	7,321
2004/05	11,385	1,771	9,613	793	725	371	26	125	252	9,091
2005/06	11,341	1,502	9,839	432	696	405	28	127	255	9,397
2006/07	11,882	1,807	10,075	433	671	429	30	128	259	9,933
2007/08	12,132	1,825	10,307	428	649	453	31	130	262	10,177
2008/09	12,374	1,856	10,517	424	631	479	33	132	266	10,409
2009/10	12,781	2,049	10,732	415	615	506	35	133	269	10,808
2010/11	13,067	2,106	10,961	417	603	534	37	135	272	11,070
2011/12	13,387	2,165	11,222	418	593	566	38	136	276	11,360
2012/13	13,688	2,230	11,458	419	586	597	40	138	279	11,629
2013/14	14,015	2,295	11,720	420	581	628	42	139	282	11,923

Historical Values (1995 - 2004):

Col. (2) = recorded peak + implemented load control + residential and commercial/industrial conservation and customer-owned self-service cogeneration.

Cols. (5) - (9) = cumulative conservation and load control capabilities at peak. Col. (8) includes commercial load management and standby generation.

Col. (OTH) = Residential Heat Works load control, voltage reduction and customer-owned self-service cogeneration.

Col. (10) = (2) - (5) - (6) - (7) - (8) - (9) - (OTH).

Projected Values (2005 - 2014):

Cols. (2) - (4) = forecasted peak without load control, conservation, and customer-owned self-service cogeneration.

Cols. (5) - (9) = cumulative conservation and load control capabilities at peak. Col. (8) includes commercial load management and standby generation.

Col. (OTH) = voltage reduction and customer-owned self-service cogeneration.

Col. (10) = (2) - (5) - (6) - (7) - (8) - (9) - (OTH).

PROGRESS ENERGY FLORIDA

SCHEDULE 3.2.3
HISTORY AND FORECAST OF WINTER PEAK DEMAND (MW)
LOW LOAD FORECAST

(1) YEAR	(2) TOTAL	(3) WHOLESALE	(4) RETAIL	(5) INTERRUPTIBLE	(6) RESIDENTIAL LOAD MANAGEMENT	(7) RESIDENTIAL CONSERVATION	(8) COMM. / IND. LOAD MANAGEMENT	(9) COMM. / IND. CONSERVATION	(OTH) OTHER DEMAND REDUCTIONS	(10) NET FIRM DEMAND
1994/95	9,084	1,145	7,939	281	997	101	5	75	131	7,494
1995/96	10,562	1,489	9,073	255	1,156	106	15	95	201	8,734
1996/97	8,486	1,235	7,251	290	917	133	16	104	190	6,836
1997/98	7,752	941	6,811	318	663	164	17	112	168	6,310
1998/99	10,473	1,741	8,732	305	874	196	18	117	187	8,776
1999/00	10,040	1,728	8,312	225	849	229	20	119	182	8,416
2000/01	11,450	1,984	9,466	255	809	254	29	120	194	9,789
2001/02	10,676	1,624	9,052	285	770	278	24	121	188	9,010
2002/03	11,555	1,538	10,017	271	768	313	27	124	200	9,852
2003/04	9,290	1,167	8,123	498	761	343	24	125	218	7,321
2004/05	11,027	1,771	9,255	793	725	371	26	125	252	8,733
2005/06	10,960	1,502	9,458	432	696	405	28	127	255	9,016
2006/07	11,442	1,807	9,635	433	671	429	30	128	259	9,493
2007/08	11,646	1,825	9,821	428	649	453	31	130	262	9,691
2008/09	11,829	1,856	9,972	424	631	479	33	132	266	9,864
2009/10	12,183	2,049	10,134	415	615	506	35	133	269	10,210
2010/11	12,379	2,106	10,273	417	603	534	37	135	272	10,382
2011/12	12,604	2,165	10,439	418	593	566	38	136	276	10,577
2012/13	12,832	2,230	10,602	419	586	597	40	138	279	10,773
2013/14	13,021	2,295	10,726	420	581	628	42	139	282	10,929

Historical Values (1995 - 2004):

Col. (2) = recorded peak + implemented load control + residential and commercial/industrial conservation and customer-owned self-service cogeneration.

Cols. (5) - (9) = cumulative conservation and load control capabilities at peak. Col. (8) includes commercial load management and standby generation.

Col. (OTH) = Residential Heat Works load control, voltage reduction and customer-owned self-service cogeneration.

Col. (10) = (2) - (5) - (6) - (7) - (8) - (9) - (OTH).

Projected Values (2005 - 2014):

Cols. (2) - (4) = forecasted peak without load control, conservation, and customer-owned self-service cogeneration.

Cols. (5) - (9) = cumulative conservation and load control capabilities at peak. Col. (8) includes commercial load management and standby generation.

Col. (OTH) = voltage reduction and customer-owned self-service cogeneration.

Col. (10) = (2) - (5) - (6) - (7) - (8) - (9) - (OTH).

PROGRESS ENERGY FLORIDA

SCHEDULE 3.3.1
HISTORY AND FORECAST OF ANNUAL NET ENERGY FOR LOAD (GWh)
BASE CASE

(1) YEAR	(2) TOTAL	(3) RESIDENTIAL CONSERVATION	(4) COMM. / IND. CONSERVATION	(OTH) OTHER ENERGY REDUCTIONS*	(5) RETAIL	(6) WHOLESALE	(7) UTILITY USE & LOSSES	(8) NET ENERGY FOR LOAD	(9) LOAD FACTOR (%) **
1995	34,696	234	246	549	29,499	1,846	2,322	33,667	49.8
1996	35,812	249	285	562	30,785	2,089	1,841	34,715	44.9
1997	35,753	268	317	563	30,850	1,758	1,997	34,605	49.0
1998	38,950	289	333	565	33,387	2,340	2,036	37,763	53.9
1999	40,376	312	339	565	33,441	3,267	2,452	39,160	50.0
2000	42,486	334	345	565	34,832	3,732	2,678	41,242	50.5
2001	42,200	354	349	564	35,263	3,839	1,831	40,933	47.5
2002	43,860	377	352	564	36,859	3,173	2,535	42,567	50.0
2003	45,232	400	357	564	37,957	3,359	2,595	43,911	47.7
2004	46,617	424	360	565	38,193	4,301	2,774	45,268	56.5
2005	49,002	445	363	564	40,286	4,620	2,724	47,630	61.0
2006	49,289	459	365	564	41,497	3,565	2,838	47,900	59.4
2007	50,778	474	368	564	42,673	3,761	2,938	49,372	58.1
2008	51,992	489	371	565	43,775	3,748	3,044	50,567	58.1
2009	53,090	504	374	564	44,892	3,674	3,082	51,648	58.2
2010	55,001	519	377	564	46,020	4,275	3,246	53,541	58.1
2011	56,362	536	380	564	47,180	4,427	3,275	54,882	58.3
2012	57,763	552	383	565	48,354	4,554	3,355	56,263	58.4
2013	59,194	568	386	564	49,535	4,706	3,435	57,676	58.8
2014	61,057	585	389	564	50,724	5,242	3,554	59,520	59.5

* Column (OTH) includes Conservation Energy For Lighting and Public Authority Customers, Customer-Owned Self-service Cogeneration and Load Control Programs.

** Load Factors for historical years are calculated using the actual winter peak demand except the 1998 and 2004 historical load factors which are based on the actual summer peak demand.
Load Factors for future years are calculated using the net firm winter peak demand (Schedule 3.2.1)

PROGRESS ENERGY FLORIDA

SCHEDULE 3.3.2
HISTORY AND FORECAST OF ANNUAL NET ENERGY FOR LOAD (GWh)
HIGH LOAD FORECAST

(1)	(2)	(3)	(4)	(OTH)	(5)	(6)	(7)	(8)	(9)
YEAR	TOTAL	RESIDENTIAL CONSERVATION	COMM. / IND. CONSERVATION	OTHER ENERGY REDUCTIONS*	RETAIL	WHOLESALE	UTILITY USE & LOSSES	NET ENERGY FOR LOAD	LOAD FACTOR (%) **
1995	34,696	234	246	549	29,499	1,846	2,322	33,667	49.8
1996	35,812	249	285	562	30,785	2,089	1,841	34,715	44.9
1997	35,753	268	317	563	30,850	1,758	1,997	34,605	49.0
1998	38,950	289	333	565	33,387	2,340	2,036	37,763	53.9
1999	40,376	312	339	565	33,441	3,267	2,452	39,160	50.0
2000	42,486	334	345	565	34,832	3,732	2,678	41,242	50.5
2001	42,200	354	349	564	35,263	3,839	1,831	40,933	47.5
2002	43,860	377	352	564	36,859	3,173	2,535	42,567	50.0
2003	45,232	400	357	564	37,957	3,359	2,595	43,911	47.7
2004	46,617	424	360	565	38,193	4,301	2,774	45,268	56.5
2005	49,904	445	363	564	41,094	4,620	2,818	48,532	60.9
2006	50,256	459	365	564	42,401	3,565	2,901	48,867	59.4
2007	51,915	474	368	564	43,736	3,761	3,012	50,509	58.0
2008	53,292	489	371	565	44,995	3,748	3,124	51,867	58.0
2009	54,471	504	374	564	46,188	3,674	3,167	53,029	58.2
2010	56,487	519	377	564	47,411	4,275	3,341	55,027	58.1
2011	58,039	536	380	564	48,743	4,427	3,389	56,559	58.3
2012	59,800	552	383	565	50,261	4,554	3,485	58,300	58.4
2013	61,478	568	386	564	51,668	4,706	3,586	59,960	58.9
2014	63,726	585	389	564	53,222	5,242	3,725	62,189	59.5

* Column (OTH) includes Conservation Energy For Lighting and Public Authority Customers, Customer-Owned Self-service Cogeneration and Load Control Programs.

** Load Factors for historical years are calculated using the actual winter peak demand except the 1998 and 2004 historical load factors which are based on the actual summer peak demand.
Load Factors for future years are calculated using the net firm winter peak demand (Schedule 3.2.2)

PROGRESS ENERGY FLORIDA

SCHEDULE 3.3.3
HISTORY AND FORECAST OF ANNUAL NET ENERGY FOR LOAD (GWh)
LOW LOAD FORECAST

(1)	(2)	(3)	(4)	(OTH)	(5)	(6)	(7)	(8)	(9)
YEAR	TOTAL	RESIDENTIAL CONSERVATION	COMM. / IND. CONSERVATION	OTHER ENERGY REDUCTIONS*	RETAIL	WHOLESALE	UTILITY USE & LOSSES	NET ENERGY FOR LOAD	LOAD FACTOR (%) **
1995	34,696	234	246	549	29,499	1,846	2,322	33,667	49.8
1996	35,812	249	285	562	30,785	2,089	1,841	34,715	44.9
1997	35,753	268	317	563	30,850	1,758	1,997	34,605	49.0
1998	38,950	289	333	565	33,387	2,340	2,036	37,763	53.9
1999	40,376	312	339	565	33,441	3,267	2,452	39,160	50.0
2000	42,486	334	345	565	34,832	3,732	2,678	41,242	50.5
2001	42,200	354	349	564	35,263	3,839	1,831	40,933	47.5
2002	43,860	377	352	564	36,859	3,173	2,535	42,567	50.0
2003	45,232	400	357	564	37,957	3,359	2,595	43,911	47.7
2004	46,617	424	360	565	38,193	4,301	2,774	45,268	56.5
2005	48,094	445	363	564	39,469	4,620	2,633	46,722	61.1
2006	48,382	459	365	564	40,650	3,565	2,778	46,993	59.5
2007	49,735	474	368	564	41,695	3,761	2,873	48,329	58.1
2008	50,871	489	371	565	42,730	3,748	2,968	49,446	58.1
2009	51,741	504	374	564	43,631	3,674	2,994	50,299	58.2
2010	53,458	519	377	564	44,581	4,275	3,142	51,998	58.1
2011	54,532	536	380	564	45,465	4,427	3,160	53,052	58.3
2012	55,778	552	383	565	46,493	4,554	3,231	54,278	58.4
2013	57,034	568	386	564	47,518	4,706	3,292	55,516	58.8
2014	58,536	585	389	564	48,358	5,242	3,399	56,999	59.5

* Column (OTH) includes Conservation Energy For Lighting and Public Authority Customers, Customer-Owned Self-service Cogeneration and Load Control Programs.

** Load Factors for historical years are calculated using the actual winter peak demand except the 1998 and 2004 historical load factors which are based on the actual summer peak demand.
Load Factors for future years are calculated using the net firm winter peak demand (Schedule 3.2.3)

PROGRESS ENERGY FLORIDA

SCHEDULE 4
PREVIOUS YEAR ACTUAL AND TWO-YEAR FORECAST OF PEAK DEMAND
AND NET ENERGY FOR LOAD BY MONTH

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	ACTUAL 2004		FORECAST 2005		FORECAST 2006	
	PEAK DEMAND	NEL	PEAK DEMAND	NEL	PEAK DEMAND	NEL
MONTH	MW	GWh	MW	GWh	MW	GWh
JANUARY	8,748	3,504	8,914	3,735	9,200	3,695
FEBRUARY	7,791	3,090	7,115	3,362	7,335	3,303
MARCH	6,017	3,171	6,008	3,601	6,216	3,553
APRIL	6,760	3,176	6,691	3,483	6,956	3,409
MAY	8,446	3,960	7,659	4,195	7,965	4,142
JUNE	9,125	4,481	8,021	4,390	8,494	4,490
JULY	9,058	4,621	8,147	4,762	8,641	4,884
AUGUST	8,842	4,432	8,172	4,802	8,663	4,918
SEPTEMBER	8,628	4,064	7,689	4,369	8,136	4,444
OCTOBER	8,324	3,900	7,146	3,904	7,561	3,945
NOVEMBER	7,313	3,237	5,792	3,379	6,149	3,422
DECEMBER	8,303	3,632	7,356	3,648	7,899	3,695
TOTAL		45,268		47,630		47,900

NOTE: "Actual" = "Total" - "Interruptible" - "Res. LM" - "C/I LM" - "Voltage Reduction & Standby Generation"

FUEL REQUIREMENTS AND ENERGY SOURCES

PEF's two-year actual and ten-year projected nuclear, coal, oil, and gas requirements (by fuel units) are shown on Schedule 5. PEF's two-year actual and ten-year projected energy sources, in GWh and percent, are shown by fuel type on Schedules 6.1 and 6.2, respectively. PEF's fuel requirements and energy sources reflect a diverse fuel supply system that is not dependent on any one-fuel source. Natural gas consumption is projected to increase as plants and purchases with tolling agreements are added to meet future load growth. PEF's coal and nuclear generation is projected to remain relatively stable over the ten-year planning horizon.

PROGRESS ENERGY FLORIDA

SCHEDULE 5

FUEL REQUIREMENTS

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
				-ACTUAL-											
	FUEL REQUIREMENTS		UNITS	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
(1)	NUCLEAR		TRILLION BTU	62	69	63	68	63	69	52	68	63	69	63	68
(2)	COAL		1,000 TON	6,173	5,915	6,057	5,729	5,889	5,714	6,006	6,017	5,975	5,816	5,926	5,899
(3)	RESIDUAL	TOTAL	1,000 BBL	10,701	10,864	11,446	8,989	12,026	9,860	10,469	10,942	10,462	9,177	9,761	8,675
(4)		STEAM	1,000 BBL	10,701	10,864	11,446	8,989	12,026	9,860	10,469	10,942	10,462	9,177	9,761	8,675
(5)		CC	1,000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(6)		CT	1,000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(7)		DIESEL	1,000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(8)	DISTILLATE	TOTAL	1,000 BBL	1,076	1,019	686	338	677	281	458	457	343	302	364	396
(9)		STEAM	1,000 BBL	119	152	24	33	26	33	29	25	30	39	37	37
(10)		CC	1,000 BBL	32	2	0	0	0	0	0	0	0	0	0	0
(11)		CT	1,000 BBL	925	865	662	305	651	248	429	432	313	263	327	359
(12)		DIESEL	1,000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(13)	NATURAL GAS	TOTAL	1,000 MCF	52,180	62,674	73,574	84,254	76,014	97,740	107,511	115,288	139,461	155,781	164,852	193,811
(14)		STEAM	1,000 MCF	832	1,071	0	0	0	0	0	0	0	0	0	0
(15)		CC	1,000 MCF	36,370	45,816	54,459	72,237	65,640	89,075	96,852	106,856	131,758	148,981	156,603	185,456
(16)		CT	1,000 MCF	14,978	15,787	19,115	12,016	10,374	8,665	10,659	8,433	7,702	6,800	8,249	8,355
(17)	OTHER (SPECIFY)														
	SEASONAL PURCHASE	CT	1,000 BBL	N/A	N/A	0	0	19	0	2	0	0	0	0	0
	SEASONAL PURCHASE	CC	1,000 MCF	N/A	N/A	0	0	0	0	0	5,038	6,875	7,065	7,510	6,647
	SEASONAL PURCHASE	CT	1,000 MCF	N/A	N/A	4,852	1,978	6,893	5,171	6,681	5,372	4,865	4,350	5,253	489

PROGRESS ENERGY FLORIDA

SCHEDULE 6.1

ENERGY SOURCES (GWh)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
				-ACTUAL-											
	ENERGY SOURCES		UNITS	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
(1)	ANNUAL FIRM INTERCHANGE 1/		GWh	97	417	922	1,501	2,018	1,791	1,980	1,878	1,496	1,407	1,493	1,018
(2)	NUCLEAR		GWh	6,039	6,703	6,069	6,636	6,089	6,655	5,087	6,636	6,143	6,655	6,143	6,636
(3)	COAL		GWh	16,111	15,063	15,723	14,797	15,267	14,753	15,550	15,595	15,501	15,035	15,369	15,260
(4)	RESIDUAL	TOTAL	GWh	6,785	6,981	7,044	5,387	7,458	5,940	6,358	6,657	6,329	5,447	5,841	5,065
(5)		STEAM	GWh	6,785	6,981	7,044	5,387	7,458	5,940	6,358	6,657	6,329	5,447	5,841	5,065
(6)		CC	GWh	0	0	0	0	0	0	0	0	0	0	0	0
(7)		CT	GWh	0	0	0	0	0	0	0	0	0	0	0	0
(8)		DIESEL	GWh	0	0	0	0	0	0	0	0	0	0	0	0
(9)	DISTILLATE	TOTAL	GWh	405	361	274	125	269	102	177	179	128	108	134	146
(10)		STEAM	GWh	0	0	0	0	0	0	0	0	0	0	0	0
(11)		CC	GWh	19	2	0	0	0	0	0	0	0	0	0	0
(12)		CT	GWh	386	359	274	125	269	102	177	179	128	108	134	146
(13)		DIESEL	GWh	0	0	0	0	0	0	0	0	0	0	0	0
(14)	NATURAL GAS	TOTAL	GWh	6,155	7,516	9,288	11,220	10,132	13,353	14,618	15,837	19,383	21,698	22,931	26,958
(15)		STEAM	GWh	83	106	0	0	0	0	0	0	0	0	0	0
(16)		CC	GWh	4,938	6,227	7,763	10,230	9,262	12,613	13,725	15,116	18,714	21,098	22,227	26,250
(17)		CT	GWh	1,134	1,183	1,525	989	869	740	893	721	669	599	704	709
(18)	OTHER 2/														
	QF PURCHASES		GWh	5,022	4,685	4,727	4,718	4,595	4,485	4,470	4,466	4,463	4,463	4,250	3,042
	IMPORT FROM OUT OF STATE		GWh	3,555	3,862	3,583	3,517	3,545	3,488	3,408	2,293	1,439	1,451	1,515	1,394
	EXPORT TO OUT OF STATE		GWh	-258	-320	0	0	0	0	0	0	0	0	0	0
(19)	NET ENERGY FOR LOAD		GWh	43,911	45,268	47,630	47,900	49,372	50,567	51,648	53,541	54,882	56,263	57,676	59,520

1/ NET ENERGY PURCHASED (+) OR SOLD (-) WITHIN THE FRCC REGION

2/ NET ENERGY PURCHASED (+) OR SOLD (-).

PROGRESS ENERGY FLORIDA

SCHEDULE 6.2

ENERGY SOURCES (PERCENT)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
				-ACTUAL-											
	ENERGY SOURCES		UNITS	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
(1)	ANNUAL FIRM INTERCHANGE 1/		%	0.2%	0.9%	1.9%	3.1%	4.1%	3.5%	3.8%	3.5%	2.7%	2.5%	2.6%	1.7%
(2)	NUCLEAR		%	13.8%	14.8%	12.7%	13.9%	12.3%	13.2%	9.8%	12.4%	11.2%	11.8%	10.7%	11.1%
(3)	COAL		%	36.7%	33.3%	33.0%	30.9%	30.9%	29.2%	30.1%	29.1%	28.2%	26.7%	26.6%	25.6%
(4)	RESIDUAL	TOTAL	%	15.5%	15.4%	14.8%	11.2%	15.1%	11.7%	12.3%	12.4%	11.5%	9.7%	10.1%	8.5%
(5)		STEAM	%	15.5%	15.4%	14.8%	11.2%	15.1%	11.7%	12.3%	12.4%	11.5%	9.7%	10.1%	8.5%
(6)		CC	%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(7)		CT	%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(8)		DIESEL	%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(9)	DISTILLATE	TOTAL	%	0.9%	0.8%	0.6%	0.3%	0.5%	0.2%	0.3%	0.3%	0.2%	0.2%	0.2%	0.2%
(10)		STEAM	%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(11)		CC	%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(12)		CT	%	0.9%	0.8%	0.6%	0.3%	0.5%	0.2%	0.3%	0.3%	0.2%	0.2%	0.2%	0.2%
(13)		DIESEL	%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(14)	NATURAL GAS	TOTAL	%	14.0%	16.6%	19.5%	23.4%	20.5%	26.4%	28.3%	29.6%	35.3%	38.6%	39.8%	45.3%
(15)		STEAM	%	0.2%	0.2%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(16)		CC	%	11.2%	13.8%	16.3%	21.4%	18.8%	24.9%	26.6%	28.2%	34.1%	37.5%	38.5%	44.1%
(17)		CT	%	2.6%	2.6%	3.2%	2.1%	1.8%	1.5%	1.7%	1.3%	1.2%	1.1%	1.2%	1.2%
(18)	OTHER 2/														
	QF PURCHASES		%	11.4%	10.3%	9.9%	9.8%	9.3%	8.9%	8.7%	8.3%	8.1%	7.9%	7.4%	5.1%
	IMPORT FROM OUT OF STATE		%	8.1%	8.5%	7.5%	7.3%	7.2%	6.9%	6.6%	4.3%	2.6%	2.6%	2.6%	2.3%
	EXPORT TO OUT OF STATE		%	-0.6%	-0.7%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(19)	NET ENERGY FOR LOAD		%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

1/ NET ENERGY PURCHASED (+) OR SOLD (-) WITHIN THE FRCC REGION.

2/ NET ENERGY PURCHASED (+) OR SOLD (-).

FORECASTING METHODS AND PROCEDURES

INTRODUCTION

Accurate forecasts of long-range electric energy consumption, customer growth and peak demand are essential elements in electric utility planning. Accurate projections of a utility's future load growth require a forecasting methodology with the ability to account for a variety of factors influencing electric energy usage over the planning horizon. PEF's forecasting framework utilizes a set of econometric models to achieve this end. This chapter will describe the underlying methodology of the customer, energy, and peak demand forecasts including any assumptions incorporated within each. Also included is a description of how Demand-Side Management (DSM) impacts the forecast, the development of high and low forecast scenarios and a review of DSM programs.

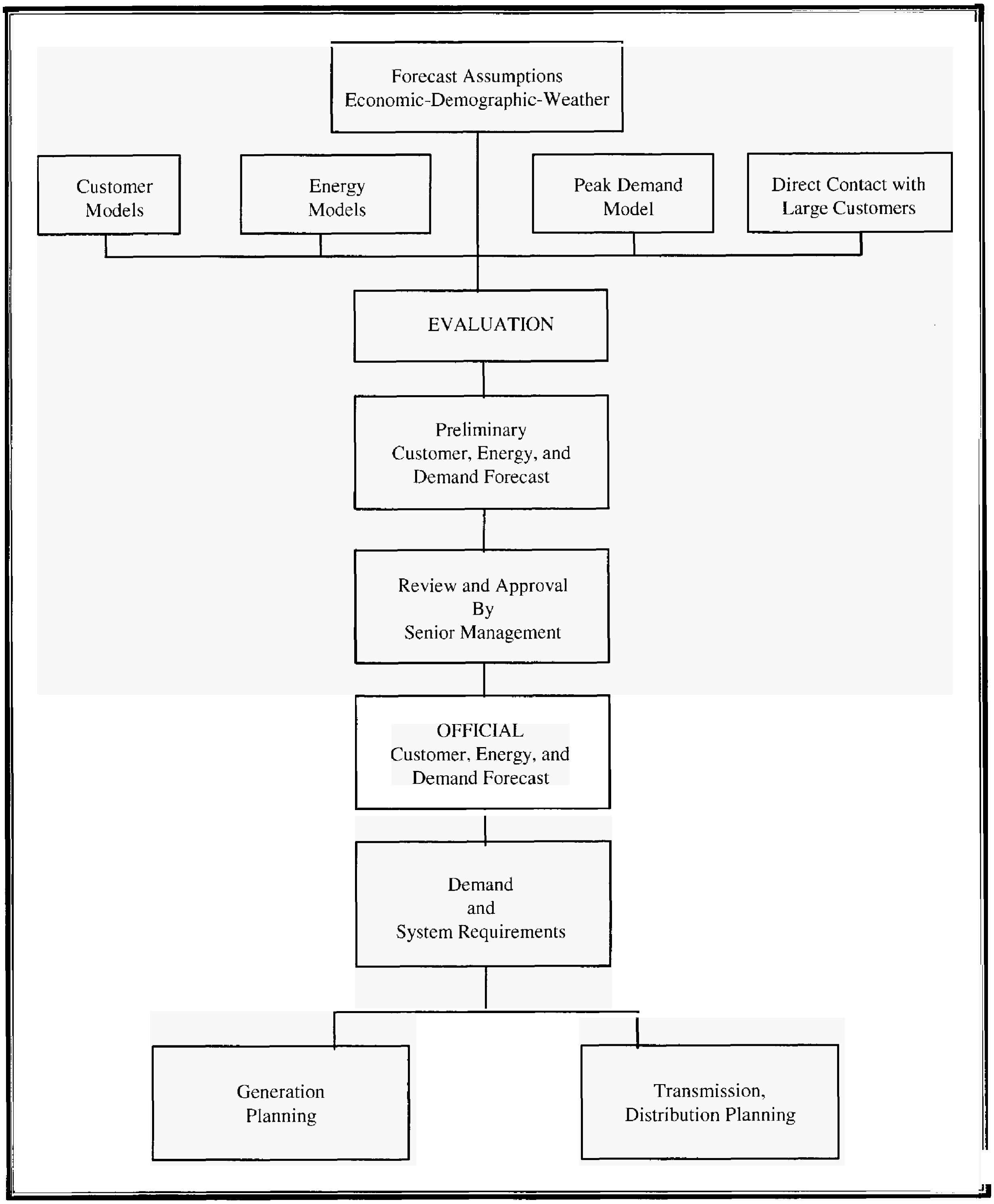
Figure 2.1, entitled "Customer, Energy and Demand Forecast", gives a general description of PEF's forecasting process. Highlighted in the diagram is a disaggregated modeling approach that blends the impacts of average class usage as well as customer growth based on a specific set of assumptions for each class. Also accounted for is some direct contact with large customers. These inputs provide the forecaster at PEF with the tools needed to frame the most likely scenario of the company's future demand.

FORECAST ASSUMPTIONS

The first step in any forecasting effort is the development of assumptions upon which the forecast is based. The Corporate Planning Department develops these assumptions based on discussions with a number of departments within PEF, as well as through the research efforts of a number of external sources. These assumptions specify major factors that influence the level of customers, energy sales, or peak demand over the forecast horizon. The following set of assumptions forms the basis for the forecast presented in this document.

FIGURE 2.1

Customer, Energy, and Demand Forecast



GENERAL ASSUMPTIONS

1. Normal weather conditions are assumed over the forecast horizon using a sales-weighted average of conditions at the St. Petersburg, Orlando and Tallahassee weather stations. For kilowatt-hour sales projections, normal weather is based on a historical thirty-year average of service area weighted billing month degree-days. Seasonal peak demand projections are based on a thirty-year historical average of system-weighted temperatures at time of seasonal peak.

2. The population projections produced by the Bureau of Economic and Business Research (BEBR) at the University of Florida as published in "Florida Population Studies Bulletin No. 138 (February 2004) provide the basis for development of the customer forecast. State and national economic assumptions produced by Economy.Com in their national and Florida forecasts (February, 2004) are also incorporated.

3. Within the Progress Energy Florida (PEF) service area the phosphate mining industry is the dominant sector in the industrial sales class. Five major customers accounted for nearly 30% of the industrial class MWh sales in 2003. These energy intensive customers mine and process phosphate-based fertilizer products for the global marketplace. Both supply and demand conditions for their products are dictated by global conditions that include, but are not limited to, foreign competition, national/international agricultural industry conditions, exchange-rate fluctuations, and international trade pacts. Load and energy consumption at the PEF-served mining or chemical processing sites depend heavily on plant operations, which are heavily influenced by the state of these global conditions as well as local conditions. After years of excess mining capacity and weak product pricing power, the industry has consolidated down to fewer players in time to take advantage of better market conditions. A weaker U.S currency value on the foreign exchange is expected to help the industry in two ways. First, American farm commodities will be more competitive overseas and lead to higher crop production at home. This will result in greater demand for fertilizer products. Second, a weak U.S. dollar results in U.S. fertilizer producers becoming more price competitive relative to foreign producers. Going forward, energy consumption is expected to increase – as we have recently experienced - to the levels just below that experienced in the late 1990 boom period. A significant risk to this projection lies in the continued high price of natural gas, which is a major

factor of production. Operations at several sites in the U.S. have already scaled back or shutdown due to profitability concerns caused by high energy prices. The energy projection for this industry assumes no major reductions or shutdowns of operations in the service territory.

4. PEF supplies load and energy service to wholesale customers on a "full", "partial" and "supplemental" requirement basis. Full requirements (FR) customers' demand and energy is assumed to grow at a rate that approximates their historical trend. Partial requirements (PR) customer load is assumed to reflect the current contractual obligations received by PEF as of May 31, 2004. The forecast of energy and demand to PR customers reflects the nature of the stratified load they have contracted for, plus their ability to receive dispatched energy from power marketers any time it is more economical for them to do so. Contracts for PR service included in this forecast are with FMPA, New Smyrna Beach, Tallahassee, Homestead, Reedy Creek Utilities, Florida Power & Light, and Seminole Electric Cooperative, Inc. (SECI). PEF's contractual arrangement with SECI includes a "supplemental" service contract (1983 contract) for service over and above stated levels they commit to supply themselves. The firm PR contract with SECI includes 150 MW of stratified intermediate service (October 1995 contract) which is projected to continue through the forecast horizon. The firm PR contract with SECI also includes amendments to provide an additional 150 MW of stratified intermediate service beginning June 2006, and 150 MW of stratified peaking service beginning December 2006. Agreements to provide interruptible service at three individual SECI metering sites have also been included in this projection. A full requirement contract has also been added to the forecast starting in 2010 and lasting through the forecast horizon. Finally, a 50MW contract – the “Market Mitigation Sale” – will be sold to SECI through March 2007.

5. This forecast assumes that PEF will successfully renew all future franchise agreements.

6. This forecast incorporates demand and energy reductions from PEF's dispatchable and non-dispatchable DSM programs required to meet the approved goals set by the Florida Public Service Commission.

7. Expected energy and demand reductions from self-service cogeneration are also included in this forecast. PEF will supply the supplemental load of self-service cogeneration customers. While PEF offers "standby" service to all cogeneration customers, the forecast does not assume an unplanned need for standby power.

8. This forecast assumes that the regulatory environment and the obligation to serve our retail customers will continue throughout the forecast horizon. Regarding wholesale customers, the company does not plan for generation resources unless a long-term contract is in place. Current FR customers are assumed to renew their contracts with PEF except those who have given notice to terminate. Current PR contracts are projected to terminate as terms reach their expiration date. Deviation from these assumptions can occur based on information provided by the Progress Energy Ventures term marketing organization.

SHORT-TERM ECONOMIC ASSUMPTIONS

The short-term economic outlook (one year out) calls for a gradual strengthening of national and State economic growth as the recovery from the recent recession takes hold and terrorism fears subside. As this forecast was developed, signs of an improving economy were beginning to be reflected in reported GDP growth. Employment growth had just commenced after a long period of contraction. Monetary policy announcements suggested a return to more normal levels of interest rates and monetary growth. A fifty-year low in market interest rates - coaxed by the Federal Reserve Board (FED) – and lower Federal tax rates appear to have stimulated the U.S. economy enough to warrant a less accommodative monetary policy.

The extremely accommodative fiscal and monetary policies since late 2001, the passage of time from the terror attack of 9/11, and the working off of excess investment of the “bubble” economy, have put the U.S. and Florida economies on track for reasonably consistent growth for the foreseeable future. As consumer confidence rebounds, more reasonable returns on investment will enable businesses to resume hiring. A weaker dollar should make domestic producers more competitive.

Particular sectors of the economy that have been performing well include the housing industry and the individual consumer. Both have been credited with fueling the limited economic advances of the past two years. The multi-generational low in interest rates and expansion of credit has stimulated an unprecedented level of housing construction. The record level of mortgage refinancing and lowering of Federal taxes have acted to put added money in people's pockets, further stimulating demand.

While most signs point toward an improving economic environment, there are some risks that were considered in the development of this forecast. Market prices for energy have been very high for an extended period at this point. Historically, high oil prices have resulted in starving economic growth. Fears of a shortage in supplies has kept natural gas prices high as well and has placed increased burden on manufacturers who rely upon reasonably priced fuel as a major source of production.

An additional risk comes as the FED increases interest rates. Some economists believe that the housing sector has been over-simulated by record-low interest rates. Others believe that Americans have "loaded up" on debt and will be negatively impacted by higher debt-service as interest rates rise. The FED must carefully balance the risks staving off higher inflation without starving economic growth. Higher inflation could force up market-driven interest rates faster than the FED would prefer. This event would certainly hurt the housing sector as well as consumer spending. This forecast tries to balance this and other risks by incorporating the National and State economic projections developed by Economy.Com.

LONG-TERM ECONOMIC ASSUMPTIONS

The long-term economic outlook assumes that changes in economic and demographic conditions will follow a trended behavior pattern. The main focus involves identifying these trends. No attempt is made to predict business cycle fluctuations during this period.

Population Growth Trends

This forecast assumes Florida will experience slower in-migration and population growth over parts of the long term, as reflected in the BEBR projections.

Florida's climate and low cost of living have historically attracted a major share of the retirement population from the eastern half of the United States. This will continue to occur, but at less than historic rates for several reasons. First, Americans entering retirement age during the late 1990s and early twenty-first century were born during the Great Depression era of the 1930s. This decade experienced a low birth rate due to the economic conditions at that time. Now that this generation is retiring, there exists a smaller pool of retirees capable of migrating to Florida. As we enter into the second decade of the new century and the baby-boom generation enters retirement age, the reverse effect can be expected.

Second, the enormous growth in population and corresponding development of the 1980s and 1990s made portions of Florida less desirable for retirement living. This diminished the quality of retiree life, and along with increasing competition from neighboring states, is expected to cause a slight decline in Florida's share of these prospective new residents over the long term.

Another reason for a population growth slowdown deals with a younger age cohort. With the bulk of Florida's in-migrants under age 45, the baby boom generation born between 1945 and 1963 helped fuel the rapid population increase Florida experienced during the 1980s. In fact, slower population in-migration to Florida can be expected as the baby boom generation enters the 40s and 50s age bracket. This age group has been significantly characterized as immobile when studies focusing on interstate population flows or job changes are conducted.

Economic Growth Trends

Florida's rapid population growth of the 1980s created a period of strong job creation, especially in the service sector industries. While the service-oriented economy expanded to support an increasing population level, there were also significant numbers of corporations migrating to Florida capitalizing on the low cost, low tax business environment. This being the case, increased job opportunities in Florida created greater in-migration among the nation's working age population. Florida's ability to attract businesses from other states because of its "comparative advantage" is expected to continue throughout the forecast period but at a less significant level. Florida's successful effort to attract a "big league" biotech firm, Script's

Research, has the potential to draw a whole new growth industry to the State, the same way Disney and NASA once did.

The forecast assumes negative growth in real electricity price. That is, the change in the nominal price of electricity over time is expected to be less than the overall rate of inflation. This also implies that fuel price escalation will track at or below the general rate of inflation throughout the forecast horizon.

Real personal incomes are assumed to increase throughout the forecast period thereby boosting the average customer's ability to purchase electricity -- especially since the price of electricity is expected to increase at a rate below general inflation. As incomes grow faster than the price of electricity, consumers, on average, will remain inclined to purchase additional electric appliances and increase their utilization of existing end-uses.

FORECAST METHODOLOGY

The PEF forecast of customers, energy sales and peak demand is developed using customer class-specific econometric models. These models are expressly designed to capture class-specific variation over time. By modeling customer growth and average energy usage individually, the forecaster can better capture subtle changes in existing customer usage as well as growth from new customers. Peak demand models are projected on a disaggregated basis as well. This allows for appropriate handling of individual assumptions in the areas of wholesale contracts, load management and interruptible service.

ENERGY AND CUSTOMER FORECAST

In the retail jurisdiction, customer class models have been specified showing a historical relationship to weather and economic/demographic indicators using monthly data for sales models and annual data for customer models. Sales are regressed against "driver" variables that best explain monthly fluctuations over the historical sample period. Forecasts of these input variables are either derived internally or come from a review of the latest projections made by several independent forecasting concerns. The external sources of data include Economy.Com and the University of Florida's Bureau of Economic and Business Research. Internal company forecasts are used for projections of electricity price, weather conditions and the length of the billing month. Normal weather, which is assumed throughout the forecast horizon, is based on the 30-year average of heating and cooling degree-days by month as measured at the St Petersburg, Orlando and Tallahassee weather stations. Projections of PEF's demand-side management (conservation programs) are also incorporated as reductions to the forecast. Specific sectors are modeled as follows:

Residential Sector

Residential kWh usage per customer is modeled as a function of real Florida personal income, cooling degree-days, heating degree-days, the real price of electricity to the residential class and the average number of billing days in each sales month. This equation captures significant variation in residential usage caused by economic cycles, weather fluctuations, electric price movements and sales month duration. Projections of kWh usage per customer combined with the customer forecast provide the forecast of total residential energy sales. The residential customer forecast is developed by correlating annual customer growth with PEF service area population growth and mortgage rates. County level population projections for the 29 counties, in which PEF serves residential customers, are provided by the BEBR.

Commercial Sector

Commercial kWh use per customer is forecast based on commercial (non-agricultural, non-manufacturing and non-governmental) employment, the real price of electricity to the commercial class, the average number of billing days in each sales month and heating and cooling degree-days. The measure of cooling degree-days utilized here differs slightly from that used in the residential sector reflecting the unique behavior pattern of this class with respect to its cooling needs. Commercial customers are projected as a function of the number of residential customers served.

Industrial Sector

Energy sales to this sector are separated into two sub-sectors. A significant portion of industrial energy use is consumed by the phosphate mining industry. Because this one industry comprises nearly a 30% share of the total industrial class, it is separated and modeled apart from the rest of the class. The term "non-phosphate industrial" is used to refer to those customers who comprise the remaining portion of total industrial class sales. Both groups are impacted significantly by changes in economic activity. However, adequately explaining sales levels requires separate explanatory variables. Non-phosphate industrial energy sales are modeled using Florida manufacturing employment and a Florida industrial production index developed by Economy.Com, the real price of electricity to the industrial class, and the average number of sales month billing days.

The industrial phosphate mining industry is modeled using customer-specific information with respect to expected market conditions. Since this sub-sector is comprised of only five customers, the forecast is dependent upon information received from direct customer contact. PEF industrial customer representatives provide specific phosphate customer information regarding customer production schedules, inventory levels, area mine-out and start-up predictions, and changes in self-generation or energy supply situations over the forecast horizon.

Street Lighting

Electricity sales to the street and highway lighting class are projected to increase due to growth in the service area population base. Because this class comprised less than 0.01% of PEF's 2004 electric sales and just 0.1% of total customers, a simple time trend was used to project energy consumption and customer growth in this class.

Public Authorities

Energy sales to public authorities (SPA), comprised mostly of government operated services, is also projected to grow with the size of the service area. The level of government services, and thus energy use per customer, can be tied to the population base, as well as to the state of the economy. Factors affecting population growth will affect the need for additional governmental services (i.e., schools, city services, etc.) thereby increasing SPA energy usage per customer. Government employment has been determined to be the best indicator of the level of government services provided. This variable, along with heating and cooling degree-days, the real price of electricity and the average number of sales month billing days, results in a significant level of explained variation over the historical sample period. Intercept shift variables are also included in this model to account for the large change in school-related energy use in the billing months of January, July and August. SPA customers are projected linearly as a function of a time-trend.

Sales for Resale Sector

The Sales for Resale sector encompasses all firm sales to other electric power entities. This includes sales to other utilities (municipal or investor-owned) as well as power agencies (Rural Electric Authority or Municipal).

Seminole Electric Cooperative, Incorporated (SECI) is a wholesale, or sales for resale, customer of PEF on both a supplemental contract basis and contract demand basis. Under the supplemental contract, PEF provides service for those energy requirements above the level of generation capacity served by either SECI's own facilities or its firm purchase obligations. Monthly supplemental energy is developed using an average of several years' historical load shape of total load in the PEF control area, subtracting out the level of SECI "committed" capacity from each hour. Beyond supplemental service, PEF has an agreement with SECI to serve stratified intermediate and peaking energy. This agreement involves serving 150 MW of stratified intermediate demand that is assumed to remain a requirement on the PEF system throughout the forecast horizon. This contract has been amended to provide an additional 150 MW stratified intermediate product and a 150 MW stratified peaking product beginning in 2006. Energy usage under this contract is projected using typical intermediate and peak load factors, respectively. Agreements to provide non-firm or interruptible service are currently in effect between PEF and SECI at three separate metering points amounting to an estimated 50 MW. Two new contracts were signed in 2004. A full requirements service contract was agreed to for 150 MW beginning in 2010 and a 50 MW contract – the "Market Mitigation Sale" begins in January 2005 and ends in March 2007.

The municipal sales for resale class includes a number of customers, divergent not only in scope of service, (i.e., full or partial requirement), but also in composition of ultimate consumers. Each customer is modeled separately in order to accurately reflect its individual profile. The majority of customers in this class are municipalities whose full energy requirements are met by PEF. The full requirement customers are modeled individually using local weather station data and population growth trends. Since the ultimate consumers of electricity in this sector are, to a large degree, residential and commercial customers, it is assumed that their use patterns will follow those of the PEF retail-based residential and commercial customer classes. PEF serves partial requirement service (PR) to municipalities such as New Smyrna Beach (NSB), Homestead and Tallahassee, and other power providers like Florida Municipal Power Agency (FMPA) and Florida Power & Light. In each case, these customers contract with PEF for a specific level and type of demand needed to provide their particular electrical system with an appropriate level of reliability. The terms of the FMPA and NSB contracts are subject to change each year via a letter of “declared” MW nomination. More specifically, this means that the level and type of demand and energy under contract can increase or decrease for each year a value is nominated. The energy forecast for each contract is derived using its historical load factors where enough history exists, or typical load factors for a given type of contracted stratified load. The energy projections for the Florida Municipal Power Agency (FMPA) also include a "losses service contract" for energy PEF supplies to FMPA for transmission losses incurred when "wheeling" power to their ultimate customers in PEF's transmission area. This projection is based on the projected requirements of the aggregated needs of the cities of Ocala, Leesburg and Bushnell.

PEAK DEMAND FORECAST

The forecast of peak demand also employs a disaggregated econometric methodology. For seasonal (winter and summer) peak demands, as well as each month of the year, PEF’s coincident system peak is dissected into five major components. These components consist of potential firm retail load, conservation and load management program capability, wholesale demand, company use demand and interruptible demand.

Potential firm retail load refers to projections of PEF retail hourly seasonal net peak demand (excluding the non-firm interruptible/curtailable/standby services) before the cumulative effects of any conservation activity or the activation of PEF's Load Management program. The historical values of this series are constructed to show the size of PEF's firm retail net peak demand assuming no utility-induced conservation or load control had taken place. The value of constructing such a "clean" series enables the forecaster to observe and correlate the underlying trend in retail peak demand to total system customer levels and coincident weather conditions at the time of the peak without the impacts of year-to-year variation in conservation activity or load control reductions. Seasonal peaks are projected using historical seasonal peak data regardless of which month the peak occurred. The projections become the potential retail demand projection for the month of January (winter) and August (summer) since this is typically when the seasonal peaks occur. The non-seasonal peak months are projected the same as the seasonal peaks, but the analysis is limited to the specific month being projected.

Energy conservation and direct load control estimates are consistent with PEF's DSM goals that have been approved by the Florida Public Service Commission. These estimates are incorporated into the MW forecast. Projections of dispatchable and cumulative non-dispatchable DSM are subtracted from the projection of potential firm retail demand resulting in a projected series of retail demand figures one would expect to occur.

Sales for Resale demand projections represent load supplied by PEF to other electric utilities such as SECI, FMPA, and other electric distribution companies. The SECI supplemental demand projection is based on a trend of their historical demand within the PEF control area. The level of MW to be served by PEF is dependent upon the amount of generation resources SECI supplies itself or contracts from others. An assumption has been made that beyond the last year of committed capacity declaration (five years out), SECI will shift their level of self-serve resources to meet their base and intermediate load needs. For FMPA and NSB demand projections, historical ratios of coincident-to-contract levels of demand are applied to future MW contract levels. Demand requirements continue at the MW level indicated by the final year in their respective contract declaration letter. The full requirements municipal demand forecast is estimated for individual cities using linear econometric equations modeling both weather and economic impacts specific to each locale. The seasonal (winter and summer) projections become the January and August peak values, respectively. The non-seasonal peak months are calculated using monthly allocation factors derived from applying the historical relationship between each winter month (November to March) relative to the winter peak, and each summer month (April to October) in relation to the summer peak demand.

PEF "company use" at the time of system peak is estimated using load research metering studies and is assumed to remain stable over the forecast horizon. The interruptible and curtailable service (IS and CS) load component is developed from historic trends, as well as the incorporation of specific information obtained from PEF's large industrial accounts by field representatives.

Each of the peak demand components described above is a positive value except for the DSM program MW impacts and IS and CS load. These impacts represent a reduction in peak demand and are assigned a negative value. Total system peak demand is then calculated as the arithmetic sum of the five components.

HIGH AND LOW FORECAST SCENARIOS

The high and low bandwidth scenarios around the base MWh energy sales forecast are developed using a Monte Carlo simulation applied to a multivariate regression model that closely replicates the base retail MWh energy forecast in aggregate. This model accounts for variation in Gross Domestic Product, retail customers and electricity price. The base forecasts for these variables were developed based on input from Economy.Com and internal company price projections. Variation around the base forecast predictor variables used in the Monte Carlo simulation was based on an 80 percent confidence interval calculated around variation in each variable's historic growth rate. While the total number of degree-days (weather) was also incorporated into the model specification, the high and low scenarios do not attempt to capture extreme weather conditions. Normal weather conditions were assumed in all three scenarios.

The Monte Carlo simulation was produced through the estimation of 1,000 scenarios for each year of the forecast horizon. These simulations allowed for random normal variation in the growth trajectories of the economic input variables (while accounting for cross-correlation amongst these variables), as well as simultaneous variation in the equation (model error) and coefficient estimates. These scenarios were then sorted and rank ordered from one to a thousand, while the simulated scenario with no variation was adjusted to equal the base forecast.

The low retail scenario was chosen from among the ranked scenarios resulting in a bandwidth forecast reflecting an approximate probability of occurrence of 0.10. The high retail scenario similarly represents a bandwidth forecast with an approximate probability of occurrence of 0.90. In both scenarios the high and low peak demand bandwidth forecasts are projected from the energy forecasts using the load factor implicit in the base forecast scenario.

CONSERVATION

PEF's historical DSM performance is shown in the following tables, which compare the conservation savings actually achieved through PEF's DSM programs for the reporting years of 2000-2004 with the Commission-approved conservations goals for those same years.

Historical Residential Conservation Savings Goals and Achievements

	Cumulative Summer MW		Cumulative Winter MW		* Annual Cumulative GWh Energy	
Year	**Goal**	**Achieved**	**Goal**	**Achieved**	**Goal**	**Achieved**
2000	10	17	30	35	15	21
2001	20	29	64	72	32	42
2002	32	43	102	111	50	65
2003	45	59	142	152	69	90
2004	58	74	185	186	88	114

Historical Commercial/Industrial Conservation Savings Goals and Achievements

	Cumulative Summer MW		Cumulative Winter MW		* Annual Cumulative GWh Energy	
Year	**Goal**	**Achieved**	**Goal**	**Achieved**	**Goal**	**Achieved**
2000	4	12	4	12	2	6
2001	8	18	7	17	4	10
2002	11	28	11	24	6	14
2003	15	35	15	29	8	18
2004	19	59	18	52	10	21

* Represents only the annual energy contribution not the total cumulative energy savings over the life of the measures.

On August 9, 2004, the FPSC issued a PAA Order approving new conservation goals for PEF that span the ten-year period from 2005 through 2014 (in Docket 040031-EG, Order No. PSC-04-0769-PAA-EG). In that same PAA Order, the Commission also approved a new DSM Plan for PEF that was specifically designed to meet the new conservation goals. The PAA Order was subsequently made effective and final in a Consummating Order (PSC-04-0852-CO-EG) issued by the Commission on September 1, 2004.

The forecasts contained in this Ten-Year Site Plan document are based on PEF's new DSM Plan and, therefore, appropriately reflect the level of DSM savings required to meet the Commission-established conservation goals. PEF's DSM Plan consists of five residential programs, seven commercial and industrial programs, and one research and development program. The programs are subject to periodic monitoring and evaluation for the purpose of ensuring that all DSM resources are acquired in a cost-effective manner and that the program savings are durable. Following is a brief description of these programs.

RESIDENTIAL PROGRAMS

Home Energy Check Program

This energy audit program provides customers with an analysis of their current energy use and recommendations on how they can save on their electricity bills through low-cost or no-cost energy-saving practices and measures. The Home Energy Check program offers PEF customers the following types of audits: Type 1: Free Walk-Through Audit (Home Energy Check); Type 2: Customer-completed Mail In Audit (Do It Yourself Home Energy Check); Type 3: Online Home Energy Check (Internet Option)-a customer-completed audit; Type 4: Phone Assisted Audit –A customer assisted survey of structure and appliance use; Type 5: Computer Assisted Audit; Type 6: Home Energy Rating Audit (Class I, II, III). The Home Energy Check Program serves as the foundation of the Home Energy Improvement Program in that the audit is a prerequisite for participation in the energy saving measures offered in the Home Energy Improvement Program.

Home Energy Improvement Program

This is the umbrella program to increase energy efficiency for existing residential homes. It combines efficiency improvements to the thermal envelope with upgraded electric appliances. The program provides incentives for attic insulation upgrades, duct testing and repair, and high efficiency electric heat pumps.

Residential New Construction Program

This program promotes energy efficient new home construction in order to provide customers with more efficient dwellings combined with improved environmental comfort. The program provides education and information to the design and building community on energy efficient equipment and construction. It also facilitates the design and construction of energy efficient homes by working directly with the builders to comply with program requirements. The program provides incentives to the builder for high efficiency electric heat pumps and high performance windows. The highest level of the program incorporates the Environmental Protection Agency's Energy Star Homes Program and qualifies participants for cooperative advertising.

Low Income Weatherization Assistance Program

This umbrella program seeks to improve energy efficiency for low-income customers in existing residential dwellings. It combines efficiency improvements to the thermal envelope with upgraded electric appliances. The program provides incentives for attic insulation upgrades, duct testing and repair, reduced air infiltration, water heater wrap, HVAC maintenance, high efficiency heat pumps, heat recovery units, and dedicated heat pump water heaters.

Residential Energy Management Program

This is a voluntary customer program that allows PEF to reduce peak demand and thus defer generation construction. Peak demand is reduced by interrupting service to selected electrical equipment with radio controlled switches installed on the customer's premises. These interruptions are at PEF's option, during specified time periods, and coincident with hours of peak demand. Participating customers receive a monthly credit on their electricity bills.

COMMERCIAL/INDUSTRIAL (C/I) PROGRAMS

Business Energy Check Program

This energy audit program provides commercial and industrial customers with an assessment of the current energy usage at their facilities, recommendations on how they can improve the environmental conditions of their facilities while saving on their electricity bills, and information on low-cost energy efficiency measures. The Business Energy Check consists of the following types of audits: A free walk-through audit, and a paid walk-through audit. Small business customers also have the option to complete a Business Energy Check online at Progress Energy's website. In most cases, this program is a prerequisite for participation in the other C/I programs.

Better Business Program

This is the umbrella efficiency program for existing commercial and industrial customers. The program provides customers with information, education, and advice on energy-related issues and incentives on efficiency measures that are cost-effective to PEF and its customers. The Better Business Program promotes energy efficient heating, ventilation, air conditioning (HVAC), and some building retrofit measures (in particular, ceiling insulation upgrade, duct leakage test and repair, energy-recovery ventilation and Energy Star cool roof coating products.)

Commercial/Industrial New Construction Program

The primary goal of this program is to foster the design and construction of energy efficient buildings. The new construction program: 1) provides education and information to the design community on all aspects of energy efficient building design; 2) requires that the building design, at a minimum, surpass the state energy code; 3) provides financial incentives for specific energy efficient equipment; and 4) provides energy design awards to building design teams. Incentives will be provided for high efficiency HVAC equipment, energy recovery ventilation and Energy Star cool roof coating products.

Innovation Incentive Program

This program promotes a reduction in demand and energy by subsidizing energy conservation projects for customers in PEF's service territory. The intent of the program is to encourage legitimate energy efficiency measures that reduce kW demand and/or kWh energy, but are not addressed by other programs. Energy efficiency opportunities are identified by PEF representatives during a Business Energy Check audit. If a candidate project meets program specifications, it will be eligible for an incentive payment, subject to PEF approval.

Commercial Energy Management Program (Rate Schedule GSLM-1)

This direct load control program reduces PEF's demand during peak or emergency conditions. As described in PEF's DSM Plan, this program is currently closed to new participants. It is applicable to existing program participants who have electric space cooling equipment suitable for interruptible operation and are eligible for service under the Rate Schedule GS-1, GST-1, GSD-1, or GSDT-1. The program is also applicable to existing participants who have any of the following electrical equipment installed on permanent residential structures and utilized for domestic (household) purposes: 1) water heater(s), 2) central electric heating systems(s), 3) central electric cooling system(s), and/or 4) swimming pool pump(s). Customers receive a monthly credit on their bills depending on the type of equipment in the program and the interruption schedule.

Standby Generation Program

This demand control program reduces PEF's demand based upon the indirect control of customer generation equipment. This is a voluntary program available to all commercial, industrial, and agricultural customers who have on-site generation capability and are willing to reduce their PEF demand when PEF deems it necessary. The customers participating in the Standby Generation program receive a monthly credit on their electricity bills according to the demonstrated ability of the customer to reduce demand at PEF's request.

Interruptible Service Program

This direct load control program reduces PEF's demand at times of capacity shortage during peak or emergency conditions. The program is available to qualified non-residential customers with an average billing demand of 500 kW or more, who are willing to have their power interrupted. PEF will have remote control of the circuit breaker or disconnect switch supplying the customer's equipment. In return for this ability to interrupt load, customers participating in the Interruptible Service program receive a monthly interruptible demand credit applied to their electric bills.

Curtailable Service

This direct load control program reduces PEF's demand at times of capacity shortage during peak or emergency conditions. The program is available to qualified non-residential customers with an average billing demand of 500 kW or more, who are willing to curtail 25 percent of their average monthly billing demand. Customers participating in the Curtailable Service program receive a monthly curtailable demand credit applied to their electric bills.

RESEARCH AND DEVELOPMENT PROGRAMS

Technology Development Program

The primary purpose of this program is to establish a system to "Aggressively pursue research, development and demonstration projects jointly with others as well as individual projects" (Rule 25-17.001, {5}(f), Florida Administration Code). PEF will undertake certain development, educational and demonstration projects that have promise to become cost-effective demand reduction and energy efficiency programs. In most cases, each demand reduction and energy efficiency project that is proposed and investigated under this program requires field testing with actual customers.

CHAPTER 3

FORECAST OF FACILITIES REQUIREMENTS

Progress Energy

This page intentionally left blank

CHAPTER 3

FORECAST OF FACILITIES REQUIREMENTS

RESOURCE PLANNING FORECAST

OVERVIEW OF CURRENT FORECAST

Supply-Side Resources

PEF has a summer total capacity resource of 9,769 MW, as shown in Table 3.1. This capacity resource includes utility purchased power (474 MW), non-utility purchased power (820 MW), combustion turbine (2,619 MW, 143 MW of which is owned by Georgia Power for the months June through September), nuclear (769 MW), fossil steam (3,882 MW) and combined-cycle plants (1,205 MW). Table 3.2 shows PEF's contracts for firm capacity provided by Qualifying Facilities (QFs).

Demand-Side Programs

Total DSM resources are shown in Schedules 3.1.1 and 3.2.1 of Chapter 2. These programs include Non-Dispatchable DSM, Interruptible Load, and Dispatchable Load Control resources. PEF's 2005 Ten-Year Site Plan Demand-Side Management projections are consistent with the DSM Goals established by the Commission in Docket No. 040031-EG.

Capacity and Demand Forecast

PEF's forecasts of capacity and demand for the projected summer and winter peaks are shown in Schedules 7.1 and 7.2, respectively. PEF's forecasts of capacity and demand are based on serving expected growth in retail requirements in its regulated service area and meeting commitments to wholesale power customers who have entered into supply contracts with PEF. In its planning process, PEF balances its supply plan for the needs of retail and wholesale customers and endeavors to ensure that cost-effective resources are available to meet the needs across the customer base. Over the years, as wholesale markets have grown more competitive, PEF has remained active in the competitive solicitations while planning in a manner that maintains an appropriate balance of commitments and resources within the overall regulated supply framework.

Base Expansion Plan

PEF's planned supply resource additions and changes are shown in Schedule 8 and are referred to as PEF's Base Expansion Plan. This Plan includes 3,357 MW (summer rating) of proposed new capacity additions through the summer of 2014. As identified in Schedule 8, PEF's next planned need is the Hines 3 Unit, a 516 MW (summer) power block with a December 2005 in-service date. PEF's self-build option for Hines Unit 3 was determined to be the most cost-effective alternative (FPSC Docket No. 020953-EI, Order No. PSC-03-0175-FOF-EI, issued February 4, 2003). After Hines 3, the next planned unit is Hines 4, 461 MW (summer) power block with a December 2007 in-service date. Hines Unit 4 was granted its Need Certificate by the FPSC in November 2004 (Docket No. 040817-EI, Order No. PSC-04-1168-FOF-EI).

PEF's Base Expansion Plan projects requirements for additional combined-cycle units with proposed in-service dates of 2009, 2010, 2012, 2013 and 2014. These high efficiency gas-fired combined-cycle units, together with the Central Power & Lime Purchase from December 2005 through December 2015, the Shady Hills Purchase from December 2006 through April 2014, and the Southern Company Purchase from June 2010 through December 2015 help the PEF system meet the growing energy requirements of its customer base and also contribute to meeting the requirements of the 1990 Clean Air Act Amendments. Fuel switching, SO_2 emission allowance purchases, re-dispatching of system generation and technology improvements are additional options available to PEF to ensure compliance with these important environmental requirements. Status reports and specifications for new generation facilities are included in Schedule 9. As shown in Schedule 10, there are no new transmission lines associated with the Hines 3 combined-cycle unit, and only one new line (Hines-West Lake Wales 230 kV) required for the Hines 4 combined-cycle unit.

Current planning studies identify gas-fired units as the most economic alternatives for system expansion over the ten-year planning term. New coal units may become a competitive option beyond the ten-year timeframe should forecasted gas prices continue to increase versus coal over that term. The uncertainties associated with fuel price forecasts and the long lead times required to site, permit, license, engineer, and construct a coal unit will require additional study of coal options in the next planning cycle.

The recently issued Clean Air Interstate Rule (CAIR) may impact PEF's need for new capacity. While a compliance plan has not yet been finalized, some alternatives may impact the capacity of existing and/or future generation resources, resulting in a need for additional capacity. Once the compliance plan has been finalized, PEF will quantify the impacts on generating resources and determine if any additional capacity is needed.

TABLE 3.1

PROGRESS ENERGY FLORIDA

TOTAL CAPACITY RESOURCES OF POWER PLANTS AND PURCHASED POWER CONTRACTS

AS OF DECEMBER 31, 2004

PLANTS	NUMBER OF UNITS	SUMMER NET DEPENDABLE CAPABILITY (MW)	
Nuclear Steam			
Crystal River	1	769	*(1)*
Total Nuclear Steam	1	769	
Fossil Steam			
Crystal River	4	2,302	
Anclote	2	993	
Paul L. Bartow	3	444	
Suwannee River	3	143	
Total Fossil Steam	12	3,882	
Combined-cycle			
Hines Energy Complex	2	998	
Tiger Bay	1	207	
Total Combined-cycle	3	1,205	
Combustion Turbine			
DeBary	10	667	
Intercession City	14	1,041	*(2)*
Bayboro	4	184	
Bartow	4	187	
Suwannee	3	164	
Turner	4	154	
Higgins	4	122	
Avon Park	2	52	
University of Florida	1	35	
Rio Pinar	1	13	
Total Combustion Turbine	47	2,619	
Total Units	**63**		
Total Net Generating Capability		**8,475**	

(1) Adjusted for sale of approximately 8.2% of total capacity
(2) Includes 143 MW owned by Georgia Power Company (Jun-Sep)

Purchased Power			
Qualifying Facility Contracts	19	820	
Investor Owned Utilities	2	474	
TOTAL CAPACITY RESOURCES		**9,769**	

TABLE 3.2

PROGRESS ENERGY FLORIDA

QUALIFYING FACILITY GENERATION CONTRACTS

AS OF DECEMBER 31, 2004

Facility Name	Firm Capacity (MW)
Bay County Resource Recovery	11.0
Cargill	15.0
Dade County Resource Recovery	43.0
El Dorado	114.2
Jefferson Power	2.0
Lake Cogen	110.0
Lake County Resource Recovery	12.8
LFC Jefferson	8.5
LFC Madison	8.5
Mulberry	79.2
Orange Cogen (CFR-Biogen)	74.0
Orlando Cogen	79.2
Pasco Cogen	109.0
Pasco County Resource Recovery	23.0
Pinellas County Resource Recovery	54.8
Ridge Generating Station	39.6
Royster	30.8
US Agrichem	5.6
TOTAL	**820.20**

PROGRESS ENERGY FLORIDA

SCHEDULE 7.1

FORECAST OF CAPACITY, DEMAND AND SCHEDULED MAINTENANCE

AT TIME OF SUMMER PEAK

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
	TOTAL INSTALLED CAPACITY	FIRM CAPACITY IMPORT	FIRM CAPACITY EXPORT	QF	TOTAL CAPACITY AVAILABLE	SYSTEM FIRM SUMMER PEAK DEMAND	RESERVE MARGIN BEFORE MAINTENANCE		SCHEDULED MAINTENANCE	RESERVE MARGIN AFTER MAINTENANCE	
YEAR	MW	MW	MW	MW	MW	MW	MW	% OF PEAK	MW	MW	% OF PEAK
2005	8,332	799 *	0	820	9,951	8,173	1,778	22%	0	1,778	22%
2006	8,848	767 *	0	820	10,435	8,663	1,772	20%	0	1,772	20%
2007	8,848	1,087	0	802	10,737	8,958	1,779	20%	0	1,779	20%
2008	9,309	1,087	0	787	11,183	9,187	1,996	22%	0	1,996	22%
2009	9,309	1,087	0	787	11,183	9,353	1,830	20%	0	1,830	20%
2010	9,785	1,098	0	787	11,670	9,719	1,951	20%	0	1,951	20%
2011	10,261	1,028	0	787	12,076	9,926	2,150	22%	0	2,150	22%
2012	10,737	1,028	0	787	12,552	10,138	2,414	24%	0	2,414	24%
2013	10,737	1,028	0	677	12,442	10,355	2,087	20%	0	2,087	20%
2014	11,689	550	0	490	12,729	10,567	2,162	20%	0	2,162	20%

* Progress Energy is pursuing seasonal purchases of approximately 300 MW in 2005 and 150 MW in 2006. The deals are not yet consummated as of the time of the Ten-Year Site Plan filing. Since the purchase is expected to be from peaking capacity, no energy impact has been included in the plan at this time.

The recently issued Clean Air Interstate Rule (CAIR) may impact PEF's need for new capacity. While a compliance plan has not yet been finalized, some alternatives may impact the capacity of existing and/or future generation resources, resulting in a need for additional capacity. Once the compliance plan has been finalized, PEF will quantify the impacts on generating resources and determine if any additional capacity is needed.

PROGRESS ENERGY FLORIDA

SCHEDULE 7.2

FORECAST OF CAPACITY, DEMAND AND SCHEDULED MAINTENANCE

AT TIME OF WINTER PEAK

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
	TOTAL INSTALLED CAPACITY	FIRM CAPACITY IMPORT	FIRM CAPACITY EXPORT	QF	TOTAL CAPACITY AVAILABLE	SYSTEM FIRM WINTER PEAK DEMAND	RESERVE MARGIN BEFORE MAINTENANCE		SCHEDULED MAINTENANCE	RESERVE MARGIN AFTER MAINTENANCE	
YEAR	MW	MW	MW	MW	MW	MW	MW	% OF PEAK	MW	MW	% OF PEAK
2004 / 05	9,174	672 *	0	820	10,666	8,914	1,752	20%	0	1,752	20%
2005 / 06	9,756	767	0	820	11,343	9,201	2,142	23%	0	2,142	23%
2006 / 07	9,756	1,287	0	802	11,844	9,704	2,140	22%	0	2,140	22%
2007 / 08	10,273	1,129	0	787	12,188	9,916	2,272	23%	0	2,272	23%
2008 / 09	10,273	1,129	0	787	12,188	10,133	2,055	20%	0	2,055	20%
2009 / 10	10,821	1,129	0	787	12,736	10,514	2,222	21%	0	2,222	21%
2010 / 11	11,369	1,140	0	787	13,295	10,741	2,554	24%	0	2,554	24%
2011 / 12	11,369	1,070	0	787	13,225	10,963	2,262	21%	0	2,262	21%
2012 / 13	11,917	1,070	0	787	13,773	11,189	2,584	23%	0	2,584	23%
2013 / 14	12,465	1,070	0	502	14,037	11,411	2,626	23%	0	2,626	23%

* Includes Seasonal Purchase of 188 MW in 2004/05

The recently issued Clean Air Interstate Rule (CAIR) may impact PEF's need for new capacity. While a compliance plan has not yet been finalized, some alternatives may impact the capacity of existing and/or future generation resources, resulting in a need for additional capacity. Once the compliance plan has been finalized, PEF will quantify the impacts on generating resources and determine if any additional capacity is needed.

PROGRESS ENERGY FLORIDA

SCHEDULE 8
PLANNED AND PROSPECTIVE GENERATING FACILITY ADDITIONS AND CHANGES

AS OF JANUARY 1, 2004 THROUGH DECEMBER 31, 2014

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
								CONST.	COM'L IN-	EXPECTED	GEN. MAX.	NET CAPABILITY			
	UNIT	LOCATION	UNIT	FUEL		FUEL TRANSPORT		START	SERVICE	RETIREMENT	NAMEPLATE	SUMMER	WINTER		
PLANT NAME	NO.	(COUNTY)	TYPE	PRI.	ALT.	PRI.	ALT.	MO. / YR	MO. / YR	MO. / YR	KW	MW	MW	STATUS	NOTES
HINES ENERGY COMPLEX	3	POLK	CC	NG	DFO	PL	TK	9/2003	12/2005			516	582	V	
HINES ENERGY COMPLEX	4	POLK	CC	NG	DFO	PL	TK	12/2005	12/2007			461	517	T	
HINES ENERGY COMPLEX	5	POLK	CC	NG	DFO	PL	TK	5/2007	12/2009			476	548	P	
HINES ENERGY COMPLEX	6	POLK	CC	NG	DFO	PL	TK	5/2008	12/2010			476	548	P	
COMBINED-CYCLE	1	UNKNOWN	CC	NG	DFO	PL	UN	10/2009	5/2012			476	548	P	
COMBINED-CYCLE	2	UNKNOWN	CC	NG	DFO	PL	UN	5/2011	12/2013			476	548	P	
COMBINED-CYCLE	3	UNKNOWN	CC	NG	DFO	PL	UN	10/2011	5/2014			476	548	P	

PROGRESS ENERGY FLORIDA

SCHEDULE 9
STATUS REPORT AND SPECIFICATIONS OF PROPOSED GENERATING FACILITIES

AS OF JANUARY 1, 2005

(1)	Plant Name and Unit Number:	HINES ENERGY COMPLEX UNIT #3
(2)	Capacity	
	a. Summer:	516
	b. Winter:	582
(3)	Technology Type:	COMBINED-CYCLE
(4)	Anticipated Construction Timing	
	a. Field construction start date:	9/2003
	b. Commercial in-service date:	12/2005 (EXPECTED)
(5)	Fuel	
	a. Primary fuel:	NATURAL GAS
	b. Alternate fuel:	DISTILLATE FUEL OIL
(6)	Air Pollution Control Strategy:	DRY LOW NOx COMBUSTION with SELECTIVE CATALYTIC REDUCTION
(7)	Cooling Method:	COOLING POND
(8)	Total Site Area:	8,200 ACRES
(9)	Construction Status:	UNDER CONSTRUCTION, MORE THAN 50% COMPLETE
(10)	Certification Status:	SITE PERMITTED
(11)	Status with Federal Agencies:	SITE PERMITTED
(12)	Projected Unit Performance Data	
	a. Planned Outage Factor (POF):	5.8 %
	b. Forced Outage Factor (FOF):	3.0 %
	c. Equivalent Availability Factor (EAF):	91.4 %
	d. Resulting Capacity Factor (%):	75.0 %
	e. Average Net Operating Heat Rate (ANOHR):	7,114 BTU/kWh
(13)	Projected Unit Financial Data	
	a. Book Life (Years):	25
	b. Total Installed Cost (In-service year $/kW):	435.57
	c. Direct Construction Cost ($/kW):	389.18
	d. AFUDC Amount ($/kW):	46.39
	e. Escalation ($/kW):	0.00
	f. Fixed O&M ($/kW-yr):	1.35
	g. Variable O&M ($/MWh):	2.15
	h. K Factor:	NO CALCULATION

PROGRESS ENERGY FLORIDA

SCHEDULE 9
STATUS REPORT AND SPECIFICATIONS OF PROPOSED GENERATING FACILITIES

AS OF JANUARY 1, 2005

(1)	Plant Name and Unit Number:	HINES ENERGY COMPLEX UNIT #4
(2)	Capacity	
	a. Summer:	461
	b. Winter:	517
(3)	Technology Type:	COMBINED-CYCLE
(4)	Anticipated Construction Timing	
	a. Field construction start date:	12/2005
	b. Commercial in-service date:	12/2007 (EXPECTED)
(5)	Fuel	
	a. Primary fuel:	NATURAL GAS
	b. Alternate fuel:	DISTILLATE FUEL OIL
(6)	Air Pollution Control Strategy:	DRY LOW NOx COMBUSTION with SELECTIVE CATALYTIC REDUCTION
(7)	Cooling Method:	COOLING POND
(8)	Total Site Area:	8,200 ACRES
(9)	Construction Status:	REGULATORY APPROVAL RECEIVED, NOT UNDER CONSTRUCTION
(10)	Certification Status:	SITE PERMITTED
(11)	Status with Federal Agencies:	SITE PERMITTED
(12)	Projected Unit Performance Data	
	a. Planned Outage Factor (POF):	6.0 %
	b. Forced Outage Factor (FOF):	3.0 %
	c. Equivalent Availability Factor (EAF):	91.2 %
	d. Resulting Capacity Factor (%):	62.0 %
	e. Average Net Operating Heat Rate (ANOHR):	7,390 BTU/kWh
(13)	Projected Unit Financial Data	
	a. Book Life (Years):	25
	b. Total Installed Cost (In-service year $/kW):	479.69
	c. Direct Construction Cost ($/kW):	429.40
	d. AFUDC Amount ($/kW):	50.29
	e. Escalation ($/kW):	0.00
	f. Fixed O&M ($/kW-yr):	1.23
	g. Variable O&M ($/MWh):	2.32
	h. K Factor:	NO CALCULATION

PROGRESS ENERGY FLORIDA

SCHEDULE 9
STATUS REPORT AND SPECIFICATIONS OF PROPOSED GENERATING FACILITIES

AS OF JANUARY 1, 2005

(1)	Plant Name and Unit Number:	HINES ENERGY COMPLEX UNIT #5 *
(2)	Capacity	
	a. Summer:	476
	b. Winter:	548
(3)	Technology Type:	COMBINED-CYCLE
(4)	Anticipated Construction Timing	
	a. Field construction start date:	5/2007
	b. Commercial in-service date:	12/2009 (EXPECTED)
(5)	Fuel	
	a. Primary fuel:	NATURAL GAS
	b. Alternate fuel:	DISTILLATE FUEL OIL
(6)	Air Pollution Control Strategy:	DRY LOW NOx COMBUSTION with SELECTIVE CATALYTIC REDUCTION
(7)	Cooling Method:	COOLING POND
(8)	Total Site Area:	8,200 ACRES
(9)	Construction Status:	PLANNED
(10)	Certification Status:	SITE PERMITTED
(11)	Status with Federal Agencies:	SITE PERMITTED
(12)	Projected Unit Performance Data	
	a. Planned Outage Factor (POF):	6.9 %
	b. Forced Outage Factor (FOF):	4.6 %
	c. Equivalent Availability Factor (EAF):	88.8 %
	d. Resulting Capacity Factor (%):	57.0 %
	e. Average Net Operating Heat Rate (ANOHR):	7,309 BTU/kWh
(13)	Projected Unit Financial Data	
	a. Book Life (Years):	25
	b. Total Installed Cost (In-service year $/kW):	500.16
	c. Direct Construction Cost ($/kW):	387.01
	d. AFUDC Amount ($/kW):	72.97
	e. Escalation ($/kW):	40.18
	f. Fixed O&M ($/kW-yr):	2.92
	g. Variable O&M ($/MWh):	1.63
	h. K Factor:	NO CALCULATION

* Progress Energy continues to evaluate alternative sites as well as repowering of existing units.

PROGRESS ENERGY FLORIDA

SCHEDULE 9
STATUS REPORT AND SPECIFICATIONS OF PROPOSED GENERATING FACILITIES

AS OF JANUARY 1, 2005

(1)	Plant Name and Unit Number:	HINES ENERGY COMPLEX UNIT #6 *
(2)	Capacity	
	a. Summer:	476
	b. Winter:	548
(3)	Technology Type:	COMBINED-CYCLE
(4)	Anticipated Construction Timing	
	a. Field construction start date:	5/2008
	b. Commercial in-service date:	12/2010 (EXPECTED)
(5)	Fuel	
	a. Primary fuel:	NATURAL GAS
	b. Alternate fuel:	DISTILLATE FUEL OIL
(6)	Air Pollution Control Strategy:	DRY LOW NOx COMBUSTION with SELECTIVE CATALYTIC REDUCTION
(7)	Cooling Method:	COOLING POND
(8)	Total Site Area:	8,200 ACRES
(9)	Construction Status:	PLANNED
(10)	Certification Status:	SITE PERMITTED
(11)	Status with Federal Agencies:	SITE PERMITTED
(12)	Projected Unit Performance Data	
	a. Planned Outage Factor (POF):	6.9 %
	b. Forced Outage Factor (FOF):	4.6 %
	c. Equivalent Availability Factor (EAF):	88.8 %
	d. Resulting Capacity Factor (%):	57.0 %
	e. Average Net Operating Heat Rate (ANOHR):	7,309 BTU/kWh
(13)	Projected Unit Financial Data	
	a. Book Life (Years):	25
	b. Total Installed Cost (In-service year $/kW):	512.66
	c. Direct Construction Cost ($/kW):	387.01
	d. AFUDC Amount ($/kW):	74.80
	e. Escalation ($/kW):	50.85
	f. Fixed O&M ($/kW-yr):	2.92
	g. Variable O&M ($/MWh):	1.63
	h. K Factor:	NO CALCULATION

* Progress Energy continues to evaluate alternative sites as well as repowering of existing units.

PROGRESS ENERGY FLORIDA

SCHEDULE 9
STATUS REPORT AND SPECIFICATIONS OF PROPOSED GENERATING FACILITIES

AS OF JANUARY 1, 2005

(1)	Plant Name and Unit Number:	COMBINED-CYCLE 1
(2)	Capacity	
	a. Summer:	476
	b. Winter:	548
(3)	Technology Type:	COMBINED-CYCLE
(4)	Anticipated Construction Timing	
	a. Field construction start date:	10/2009
	b. Commercial in-service date:	5/2012 (EXPECTED)
(5)	Fuel	
	a. Primary fuel:	NATURAL GAS
	b. Alternate fuel:	DISTILLATE FUEL OIL
(6)	Air Pollution Control Strategy:	DRY LOW NOx COMBUSTION with SELECTIVE CATALYTIC REDUCTION
(7)	Cooling Method:	UNKNOWN
(8)	Total Site Area:	UNKNOWN ACRES
(9)	Construction Status:	PLANNED
(10)	Certification Status:	PLANNED
(11)	Status with Federal Agencies:	PLANNED
(12)	Projected Unit Performance Data	
	a. Planned Outage Factor (POF):	6.9 %
	b. Forced Outage Factor (FOF):	4.6 %
	c. Equivalent Availability Factor (EAF):	88.8 %
	d. Resulting Capacity Factor (%):	57.0 %
	e. Average Net Operating Heat Rate (ANOHR):	7,309 BTU/kWh
(13)	Projected Unit Financial Data	
	a. Book Life (Years):	25
	b. Total Installed Cost (In-service year $/kW):	538.62
	c. Direct Construction Cost ($/kW):	387.01
	d. AFUDC Amount ($/kW):	78.60
	e. Escalation ($/kW):	73.01
	f. Fixed O&M ($/kW-yr):	2.92
	g. Variable O&M ($/MWh):	1.63
	h. K Factor:	NO CALCULATION

PROGRESS ENERGY FLORIDA

SCHEDULE 9
STATUS REPORT AND SPECIFICATIONS OF PROPOSED GENERATING FACILITIES

AS OF JANUARY 1, 2005

(1)	Plant Name and Unit Number:	COMBINED-CYCLE 2
(2)	Capacity	
	a. Summer:	476
	b. Winter:	548
(3)	Technology Type:	COMBINED-CYCLE
(4)	Anticipated Construction Timing	
	a. Field construction start date:	5/2011
	b. Commercial in-service date:	12/2013 (EXPECTED)
(5)	Fuel	
	a. Primary fuel:	NATURAL GAS
	b. Alternate fuel:	DISTILLATE FUEL OIL
(6)	Air Pollution Control Strategy:	DRY LOW NOx COMBUSTION with SELECTIVE CATALYTIC REDUCTION
(7)	Cooling Method:	UNKNOWN
(8)	Total Site Area:	UNKNOWN ACRES
(9)	Construction Status:	PLANNED
(10)	Certification Status:	PLANNED
(11)	Status with Federal Agencies:	PLANNED
(12)	Projected Unit Performance Data	
	a. Planned Outage Factor (POF):	6.9 %
	b. Forced Outage Factor (FOF):	4.6 %
	c. Equivalent Availability Factor (EAF):	88.8 %
	d. Resulting Capacity Factor (%):	57.0 %
	e. Average Net Operating Heat Rate (ANOHR):	7,309 BTU/kWh
(13)	Projected Unit Financial Data	
	a. Book Life (Years):	25
	b. Total Installed Cost (In-service year $/kW):	552.08
	c. Direct Construction Cost ($/kW):	387.01
	d. AFUDC Amount ($/kW):	80.55
	e. Escalation ($/kW):	84.52
	f. Fixed O&M ($/kW-yr):	2.92
	g. Variable O&M ($/MWh):	1.63
	h. K Factor:	NO CALCULATION

PROGRESS ENERGY FLORIDA

SCHEDULE 9
STATUS REPORT AND SPECIFICATIONS OF PROPOSED GENERATING FACILITIES

AS OF JANUARY 1, 2005

(1)	Plant Name and Unit Number:	COMBINED-CYCLE 3
(2)	Capacity	
	a. Summer:	476
	b. Winter:	548
(3)	Technology Type:	COMBINED-CYCLE
(4)	Anticipated Construction Timing	
	a. Field construction start date:	10/2011
	b. Commercial in-service date:	5/2014 (EXPECTED)
(5)	Fuel	
	a. Primary fuel:	NATURAL GAS
	b. Alternate fuel:	DISTILLATE FUEL OIL
(6)	Air Pollution Control Strategy:	DRY LOW NOx COMBUSTION with SELECTIVE CATALYTIC REDUCTION
(7)	Cooling Method:	UNKNOWN
(8)	Total Site Area:	UNKNOWN ACRES
(9)	Construction Status:	PLANNED
(10)	Certification Status:	PLANNED
(11)	Status with Federal Agencies:	PLANNED
(12)	Projected Unit Performance Data	
	a. Planned Outage Factor (POF):	6.9 %
	b. Forced Outage Factor (FOF):	4.6 %
	c. Equivalent Availability Factor (EAF):	88.8 %
	d. Resulting Capacity Factor (%):	57.0 %
	e. Average Net Operating Heat Rate (ANOHR):	7,309 BTU/kWh
(13)	Projected Unit Financial Data	
	a. Book Life (Years):	25
	b. Total Installed Cost (In-service year $/kW):	565.88
	c. Direct Construction Cost ($/kW):	387.01
	d. AFUDC Amount ($/kW):	82.56
	e. Escalation ($/kW):	96.31
	f. Fixed O&M ($/kW-yr):	2.92
	g. Variable O&M ($/MWh):	1.63
	h. K Factor:	NO CALCULATION

PROGRESS ENERGY FLORIDA

SCHEDULE 10
STATUS REPORT AND SPECIFICATIONS OF PROPOSED DIRECTLY ASSOCIATED TRANSMISSION LINES

HINES UNIT #3

(1)	POINT OF ORIGIN AND TERMINATION:	N/A
(2)	NUMBER OF LINES:	N/A
(3)	RIGHT-OF-WAY:	N/A
(4)	LINE LENGTH:	N/A
(5)	VOLTAGE:	N/A
(6)	ANTICIPATED CONSTRUCTION TIMING:	N/A
(7)	ANTICIPATED CAPITAL INVESTMENT:	N/A
(8)	SUBSTATIONS:	N/A
(9)	PARTICIPATION WITH OTHER UTILITIES:	N/A

PROGRESS ENERGY FLORIDA

SCHEDULE 10
STATUS REPORT AND SPECIFICATIONS OF PROPOSED DIRECTLY ASSOCIATED TRANSMISSION LINES

HINES UNIT #4

(1) POINT OF ORIGIN AND TERMINATION:	West Lake Wales Substation-Hines Energy Complex
(2) NUMBER OF LINES:	1
(3) RIGHT-OF-WAY:	Existing Hines Energy Complex Site and new transmission Right of Way
(4) LINE LENGTH:	21
(5) VOLTAGE:	230kV
(6) ANTICIPATED CONSTRUCTION TIMING:	5/2007
(7) ANTICIPATED CAPITAL INVESTMENT:	$26,500,000
(8) SUBSTATIONS:	N/A
(9) PARTICIPATION WITH OTHER UTILITIES:	N/A

INTEGRATED RESOURCE PLANNING OVERVIEW

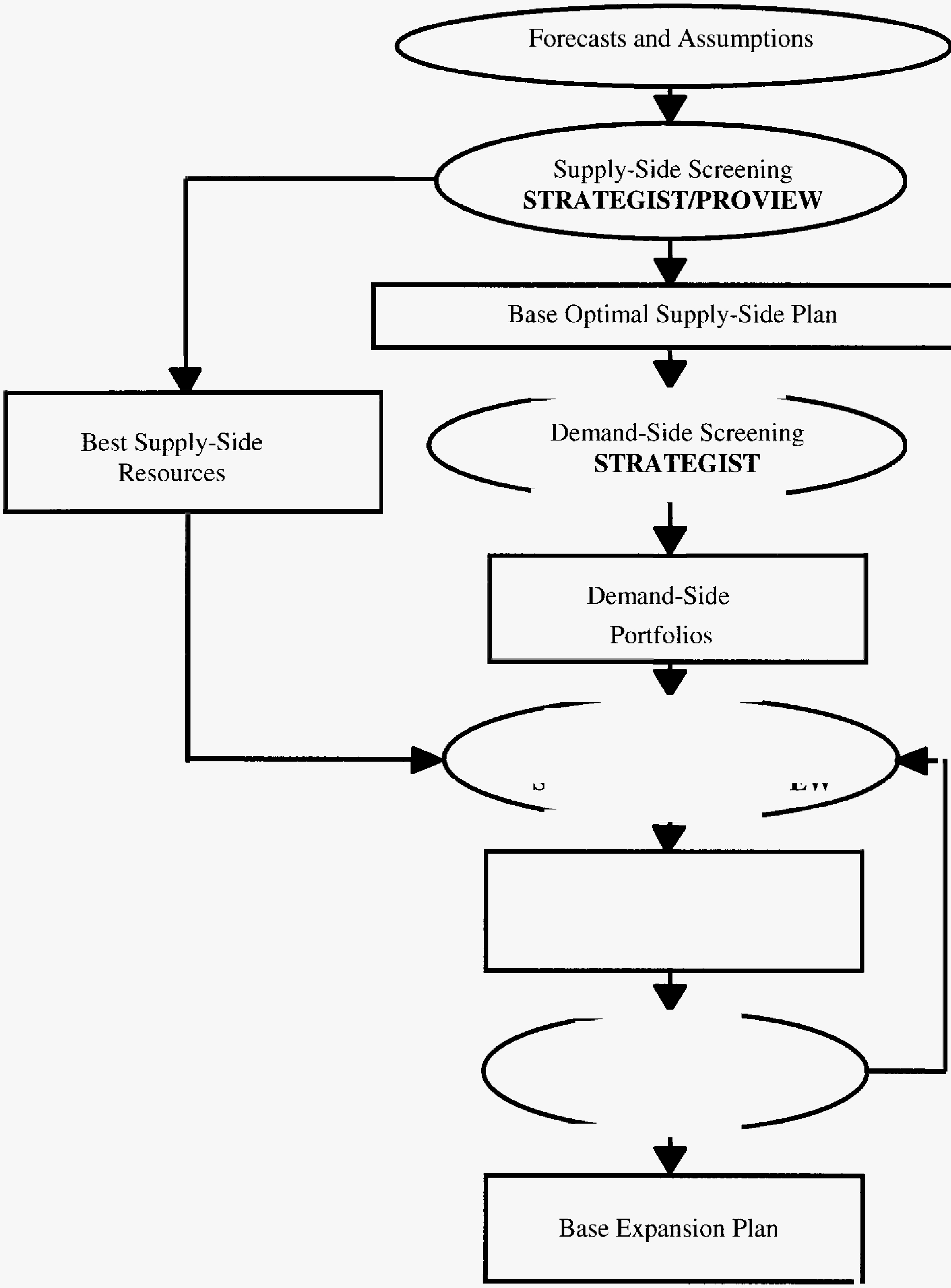
PEF employs an Integrated Resource Planning (IRP) process to determine the most cost-effective mix of supply- and demand-side alternatives that will reliably satisfy our customers' future demand and energy needs. PEF's IRP process incorporates state-of-the-art computer models used to evaluate a wide range of future generation alternatives and cost-effective conservation and dispatchable demand-side management programs on a consistent and integrated basis.

An overview of PEF's IRP Process is shown in Figure 3.1. The process begins with the development of various forecasts, including demand and energy, fuel prices, and economic assumptions. Future supply- and demand-side resource alternatives are identified and extensive cost and operating data are collected to enable these to be modeled in detail. These alternatives are optimized together to determine the most cost-effective plan for PEF to pursue over the next ten years to meet the company's reliability criteria. The resulting ten-year plan, the Integrated Optimal Plan, is then tested under different relevant sensitivity scenarios to identify variances, if any, which would warrant reconsideration of any of the base plan assumptions. If the plan is judged robust under sensitivity analysis and works within the corporate framework, it evolves as the Base Expansion Plan. This process is discussed in more detail in the following section titled "The IRP Process".

The Integrated Resource Plan provides PEF with substantial guidance in assessing and optimizing the Company's overall resource mix on both the supply side and the demand side. When a decision supporting a significant resource commitment is being developed (e.g. plant construction, power purchase, DSM program implementation), the Company will move forward with directional guidance from the IRP and delve much further into the specific levels of examination required. This more detailed assessment will typically address very specific technical requirements and cost estimates, detailed corporate financial considerations, and the most current dynamics of the business and regulatory environments.

FIGURE 3.1

IRP Process Overview



THE IRP PROCESS

Forecasts and Assumptions

The evaluation of possible supply- and demand-side alternatives, and development of the optimal plan, is an integral part of the IRP process. These steps together comprise the integration process that begins with the development of forecasts and collection of input data. Base forecasts that reflect PEF's view of the most likely future scenarios are developed, along with high and low forecasts that reflect alternative future scenarios. Computer models used in the process are brought up-to-date to reflect this data, along with the latest operating parameters and maintenance schedules for PEF's existing generating units. This establishes a consistent starting point for all further analysis.

Reliability Criteria

Utilities require a margin of generating capacity above the firm demands of their customers in order to provide reliable service. Periodic scheduled outages are required to perform maintenance and inspections of generating plant equipment and to refuel nuclear plants. At any given time during the year, some capacity may be out of service due to unanticipated equipment failures resulting in forced outages of generation units. Adequate reserve capacity must be available to accommodate these outages and to compensate for higher than projected peak demand due to forecast uncertainty and abnormal weather. In addition, some capacity must be available for operating reserves to maintain the balance between supply and demand on a moment-to-moment basis.

PEF plans its resources in a manner consistent with utility industry planning practices, and employs both deterministic and probabilistic reliability criteria in the resource planning process. A Reserve Margin criterion is used as a deterministic measure of PEF's ability to meet its forecasted seasonal peak load with firm capacity. The FPSC approved a joint proposal from the investor-owned utilities in peninsular Florida to increase the minimum planning Reserve Margin level to 20 percent (Docket No. 981890-EU, Order No. PSC-99-2507-S-EU). PEF thus plans its resources to satisfy the 20 percent minimum Reserve Margin criterion.

Loss of Load Probability (LOLP) is a probabilistic criterion that measures the probability that a company will be unable to meet its load throughout the year. While Reserve Margin only considers the peak load and amount of installed resources, LOLP also takes into account generating unit sizes, capacity mix, maintenance scheduling, unit availabilities, and capacity assistance available from other utilities. A standard probabilistic reliability threshold commonly used in the electric utility industry, and the criterion employed by PEF, is a maximum of one day in ten years loss of load probability.

PEF has based its resource planning on the use of dual reliability criteria since the early 1990s, a practice that has been accepted by the FPSC. PEF's resource portfolio is designed to satisfy the minimum 20% Reserve Margin requirement and probabilistic analyses are conducted to ensure that the one day in ten years LOLP criterion is also satisfied. By using both the Reserve Margin and LOLP planning criteria, PEF's resource portfolio is designed to have sufficient capacity available to meet customer peak demand, and to provide reliable generation service under all expected load conditions.

Supply-Side Screening

Potential supply-side resources are screened to determine those that are the most cost-effective. Data used for the screening analysis is compiled from various industry sources and PEF's experiences. The wide range of resource options is pre-screened to set aside those that do not warrant a detailed cost-effectiveness analysis. Typical screening criteria are costs, fuel source, technology maturity, environmental parameters, and overall resource feasibility.

Economic evaluation of generation alternatives is performed using the PROVIEW module of the STRATEGIST optimization program. The optimization program evaluates revenue requirements for specific resource plans generated from multiple combinations of future resource additions that meet system reliability criteria and other system constraints. All resource plans are then ranked by system revenue requirements. The optimization run produces the optimal supply-side resource plan, which is considered the "Base Optimal Supply-Side Plan."

Demand-Side Screening

Like supply-side resources, data for large numbers of potential demand-side resources is also collected. These resources are pre-screened to eliminate those alternatives that are still in research and development, addressed by other regulations (building code), or not applicable to PEF's customers. The demand-side screening module of STRATEGIST, DCE, is updated with cost data and load impact parameters for each potential DSM measure to be evaluated.

The Base Optimal Supply-Side Plan is used to establish avoidable units for screening future demand-side resources. Each future demand-side alternative is individually tested in this plan over the ten-year planning horizon to determine the benefit or detriment that the addition of this demand-side resource provides to the overall system. DCE calculates the benefits and costs for each demand-side measure evaluated and reports the appropriate ratios for the Rate Impact Measure (RIM), the Total Resource Cost Test (TRC), and the Participant Test. Demand-side programs that pass the RIM test are then bundled together to create demand-side portfolios. These portfolios contain the appropriate DSM options and make the optimization solvable with the STRATEGIST model.

Resource Integration and the Integrated Optimal Plan

The cost-effective generation alternatives and the demand-side portfolios developed in the screening process can then be optimized together to formulate an Integrated Optimal Plan. The optimization program considers all possible future combinations of supply- and demand-side alternatives that meet the company's reliability criteria in each year of the ten-year study period and reports those that provide both flexibility and low revenue requirements for PEF's ratepayers.

Developing the Base Expansion Plan

The plans that provide the lowest revenue requirements are then further tested using sensitivity analysis. The economics of the plan may be evaluated under high and low forecast scenarios for load, fuel, and financial assumptions, or any other sensitivities which, in the judgment of the planner, are relevant given existing circumstances **to** ensure that the plan does not unduly burden the company or the ratepayers if the future unfolds in a manner significantly different from the base forecasts. From the sensitivity assessment, the ten-year plan that is identified as achieving the best balance of flexibility and cost is then reviewed within the corporate framework to determine how the plan potentially impacts or is impacted by many other factors. If the plan is judged robust under this review, it evolves as the Base Expansion Plan.

KEY CORPORATE FORECASTS

Fuel Forecast

Base Fuel Case: The base case fuel price forecast was developed using short-term and long-term market price projections from industry-recognized sources. Coal prices are expected to be relatively stable month to month; however, oil and natural gas prices are expected to be more volatile on a day-to-day and month-to-month basis.

In the short term, the base cost for coal is based on the existing contractual structure between Progress Fuels Corporation (PFC) and Progress Energy Florida and both contract and spot market coal and transportation arrangements between PFC and its various suppliers. For the longer term, the costs are based on market forecasts reflective of expected market conditions. Oil and natural gas prices are estimated based on current and expected contracts and spot purchase arrangements as well as near-term and long-term market forecasts. Oil and natural gas commodity prices are driven primarily by open market forces of supply and demand. Natural gas firm transportation cost is determined primarily by pipeline tariff rates and tends to change less frequently than commodity prices.

Financial Forecast

The key financial assumptions used in PEF's most recent planning studies were 48% debt and 52% equity PEF capital structure, projected debt cost of 6.5%, and an equity return of 12.0%. These assumptions resulted in a weighted average cost of capital of 9.36% and an after-tax discount rate of 8.16%. In recent planning work, PEF did not test the sensitivity of the base resource plan to varying financial assumptions. This is due to the fact that the most economical options are combined-cycle (CC) and combustion turbine (CT) gas-fired units with relatively short construction lead times and low capital costs. These options have lower capital costs than other alternatives; therefore, higher financial assumptions would not be expected to alter the results in any significant way.

Lower cost of capital escalation rates would favor options with longer construction lead times and higher capital costs. However, PEF does not expect escalation rates to go much lower than the current base case forecast. Consequently, PEF does not believe that financial assumption sensitivity cases are needed.

CURRENT PLANNING RESULTS

TYSP Supply-Side Resources

In this TYSP, PEF's supply-side resources include the projected combined-cycle expansion of the Hines Energy Complex (HEC) with Units 3 through 6 forecasted to be in-service by December 2005, 2007, 2009, and 2010. As new advancements in combined-cycle technologies mature, PEF will continue to examine the merits of these new alternatives to ensure the lowest possible expansion costs. PEF will also continue to evaluate alternatives to construction at Hines, including alternative sites and the repowering of existing units. The TYSP also includes three generic combined-cycle units with planned in-service dates of May 2012, December 2013, and May 2014. The Company is currently conducting detailed analyses of generation sites and has not finalized its decision on the preferred site(s) for the future generic combined-cycle units

TRANSMISSION PLANNING

PEF's transmission planning assessment practices are developed to test the ability of the planned system to meet the reliability criteria as outlined in the FERC Form 715 filing. This involves the use of load flow and transient stability programs to model various contingency situations that may occur, and determining if the system response meets the reliability criteria. In general, this involves running simulations for the loss of any single line, generator, or transformer. PEF normally runs this analysis for system load levels from minimum to peak for all possible contingencies, and for both summer and winter. Additional studies are performed to determine the system response to credible, less probable criteria, to assure the system meets PEF and Florida Reliability Coordinating Council, Inc. (FRCC) criteria. These studies include the loss of multiple generators or lines, and combinations of each, and some load loss is permissible under these more severe disturbances. These credible, less probable scenarios are also evaluated at various load levels, since some of the more severe situations occur at average or minimum load conditions. In particular, critical fault clearing times are typically the shortest (most severe) at minimum load conditions, with just a few large base load units supplying the system needs.

As noted in the PEF reliability criteria, some remedial actions are allowed to reduce system loadings, in particular, sectionalizing is allowed to reduce loading on lower voltage lines for bulk system contingencies, but the risk to load on the sectionalized system must be reasonable (it would not be considered prudent to operate for long periods with a sectionalized system). In addition, the number of remedial action steps and the overall complexity of the scheme are evaluated to determine overall acceptability.

Presently, PEF uses the following reference documents to calculate Available Transfer Capability (ATC) for required transmission path postings on the Florida Open Access Same-Time Information System (OASIS):

- FRCC: FRCC ATC Calculation and Coordination Procedures, November 4, 2003, which is posted on the FRCC website: (http://www.frcc.com/downloads/frccatc.pdf)

- NERC: Transmission Transfer Capability, May 1, 1995

- NERC: Available Transfer Capability – Definitions and Determination, July 30, 1996

PEF uses the FRCC Capacity Benefit Margin (CBM) methodology to assess its CBM needs. This methodology is:
"FRCC Transmission Providers make an assessment of the CBM needed on their respective systems by using either deterministic or probabilistic generation reliability analysis. The appropriate amount of transmission interface capability is then reserved for CBM on a per interface basis, taking into account the amount of generation available on other interconnected systems, the respective load peaking diversities of those systems, and Transmission Reliability Margin (TRM). Operating reserves may be included if appropriate in TRM and subsequently subtracted from the CBM if needed."

PEF currently has zero CBM reserved on each of its interfaces (posted paths). PEF's CBM on each path is currently established through the transmission provider functions within PEF using deterministic and probabilistic generation reliability analysis.

Currently, PEF proposes no bulk transmission additions that must be certified under the Florida Transmission Line Siting Act (TLSA). PEF's proposed bulk transmission line additions are shown below:

TABLE 3.3
PROGRESS ENERGY FLORIDA

LIST OF PROPOSED BULK TRANSMISSION LINE ADDITIONS

2005-2014

MVA RATING WINTER	LINE OWNERSHIP	TERMINALS		LINE LENGTH (CKT.-MILES)	COMMERCIAL IN-SERVICE DATE (MO./YEAR)	NOMINAL VOLTAGE (kV)
1141	PEF/FPL	VANDOLAH	WHIDDEN	14	6/2005	230
1141	PEF	LAKE BRYAN	WINDERMERE #1	10 *	10 / 2006	230
1141	PEF	LAKE BRYAN	WINDERMERE #2	10	10 / 2006	230
1141	PEF	HINES ENERGY COMPLEX	WEST LAKE WALES #1	21	5 / 2007	230
1141	PEF	INTERCESSION CITY	GIFFORD	10	4 / 2008	230
1141	PEF	HINES ENERGY COMPLEX	WEST LAKE WALES #2	21	5 / 2009	230
1141	PEF/FPL	VANDOLAH	CHARLOTTE	55*	5/2009	230
1141	PEF	INTERCESSION CITY	WEST LAKE WALES #1	30 *	6 / 2010	230
1141	PEF	INTERCESSION CITY	WEST LAKE WALES #2	30	6 / 2010	230

* Rebuild existing circuit

CHAPTER 4

ENVIRONMENTAL AND LAND USE INFORMATION

Progress Energy

This page intentionally left blank

CHAPTER 4

ENVIRONMENTAL AND LAND USE INFORMATION

PREFERRED SITES

PEF's base expansion plan proposes new combined-cycle generation at the Hines Energy Complex (HEC) site in Polk County. Although not delineated in the base expansion plan, new proposed peaking simple-cycle combustion turbine generation site options include Intercession City (Osceola County) and DeBary (Volusia County). While the Intercession City, DeBary, and Hines sites are suitable for new generation, PEF continues to evaluate other available options for future supply alternatives, including the potential repowering of existing Bartow steam units.

The next proposed combined-cycle units at the HEC site are scheduled for commercial operation in December 2005 and December 2007. PEF continues to pursue siting opportunities for undesignated combined-cycle units with a commercial operation date of 2012 and beyond. PEF's existing sites, as identified in Table 3.1 of Chapter 3, include the capability to further develop generation. All appropriate permitting requirements will be addressed for PEF's preferred sites as discussed in the following site descriptions. The base expansion plan does not currently include any potential new sites for generating additions. Therefore, detailed environmental or land use data are not included.

HINES ENERGY COMPLEX SITE

In 1990, PEF completed a statewide search for a new 3,000 MW coal capable power plant site. As a result of this work, a large tract of mined-out phosphate land in south central Polk County was selected as the primary alternative. This 8,200-acre site is located south of the City of Bartow, near the cities of Fort Meade and Homeland, south of S.R. 640 and west of U.S. 17/98 (reference Figure 4.1). It is an area that has been extensively mined and remains predominantly unreclaimed.

The Governor and cabinet approved site certification for ultimate site development and construction of the first 470 MW increment on January 25, 1994, in accordance with the rules of the Power Plant Siting Act. Due to the thorough screening during the selection process, and the disturbed nature of the site, there were no major environmental limitations. As would be the situation at any location in the state, air emissions and water consumption were significant issues during the licensing process.

The site's initial preparation involved moving over 10 million cubic yards of soil and draining 4 billion gallons of water. Construction of the energy complex will recycle the land for a beneficial use and promote habitat restoration.

The Hines Energy Complex is visited by several species of wildlife, including alligators, bobcats, turtles, and over 50 species of birds. The Hines site also contains a wildlife corridor, which creates a continuous connection between the Peace River and the Alafia River.

PEF arranged for the City of Bartow to provide treated effluent for cooling pond make-up. The complex's cooling pond initially covered 722 acres with an eventual expansion to 2,500 acres.

The Hines Energy Complex is designed and permitted to be a zero discharge site. This means that there will be no discharges to surface waters either from the power plant facilities or from storm water runoff. Based on this design, storm water runoff from the site can be used as cooling pond make-up, minimizing groundwater withdrawals.

The Florida Department of Environmental Protection air rules currently list all of Polk County as attainment for ambient air quality standards. The environmental impact on the site will be minimized by PEF's close coordination with regulatory agencies to ensure compliance with all applicable environmental regulations.

As future generation units are added, the remaining network of on-site clay settling ponds will be converted to cooling ponds and combustion waste storage areas to support power plant operations. Given the disturbed nature of the property, considerable development has been required in order to make it usable for electric utility application. An industrial rail network and an adequate road system service the site.

The first combined-cycle unit at this site, with a capacity of 482 MW summer, began commercial operation in April 1999. The transmission improvements associated with this first unit were the rebuilding of the 230/115 kV double circuit Barcola to Ft. Meade line by increasing the conductor sizes and converting the line to double circuit 230 kV operation.

The second combined-cycle unit at this site entered commercial operation in December 2003 with seasonal capacity ratings of 516 MW summer. The transmission improvement associated with the second combined-cycle unit at this site involved the addition of a 230 kV circuit from the Hines Energy Complex to Barcola.

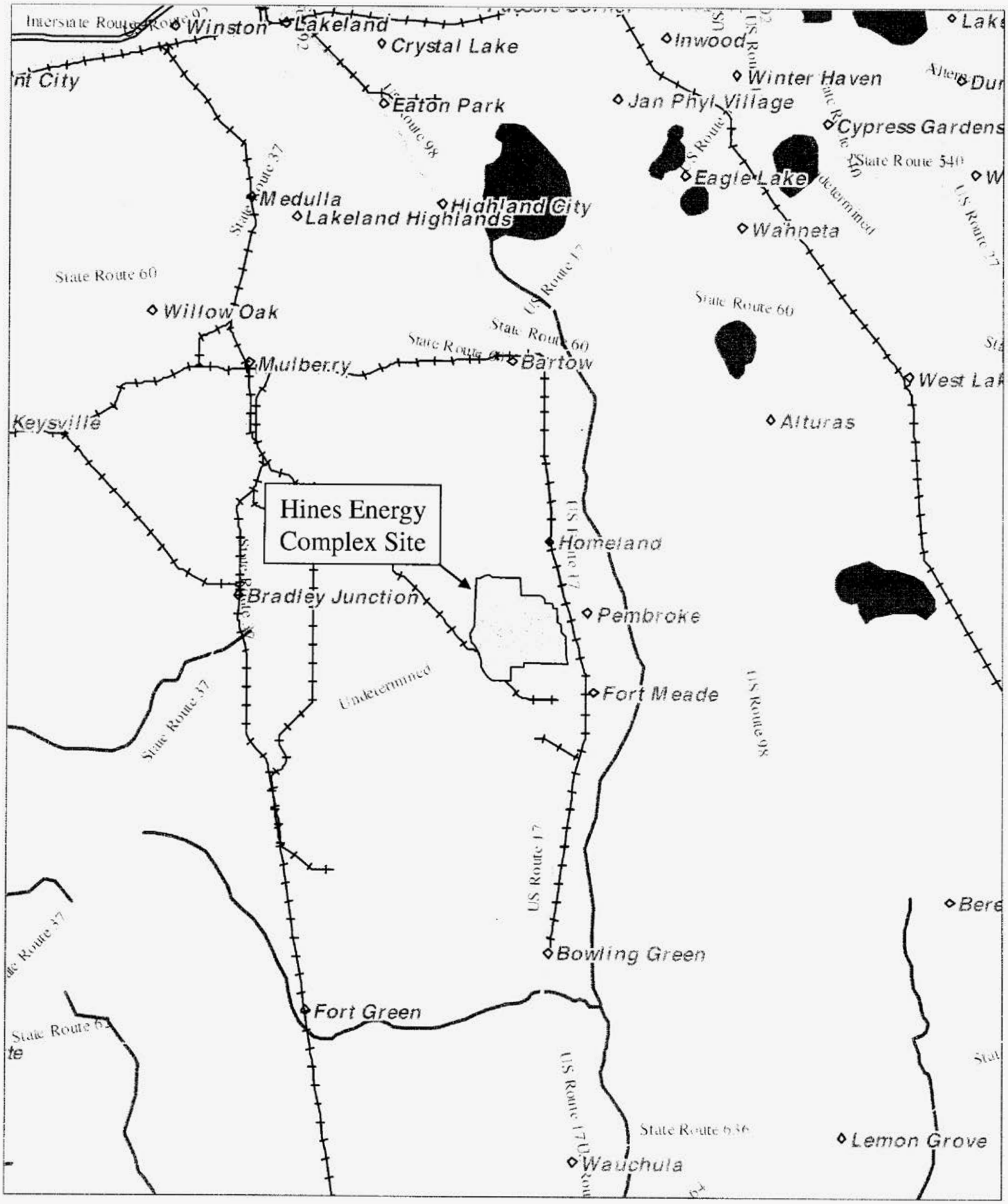
The third HEC combined-cycle unit is planned for commercial operation in December 2005 with seasonal capacity ratings of 516 MW summer, and requires no transmission upgrades.

The fourth HEC combined-cycle unit is planned for commercial operation in December 2007 with seasonal capacity ratings of 461 MW summer. The transmission improvements associated with the fourth combined-cycle unit at this site involved the addition of a 230 kV circuit from the Hines Energy Complex to West Lake-Wales and associated substation expansion and breaker replacements.

The HEC is also PEF's preferred site for future Hines 5 and 6 combined-cycle units required in 2009 and 2010, respectively.

FIGURE 4.1

Hines Energy Complex Site (Polk County)



INTERCESSION CITY SITE

Intercession City was chosen as a potential site for installation of peaking combustion turbine units.

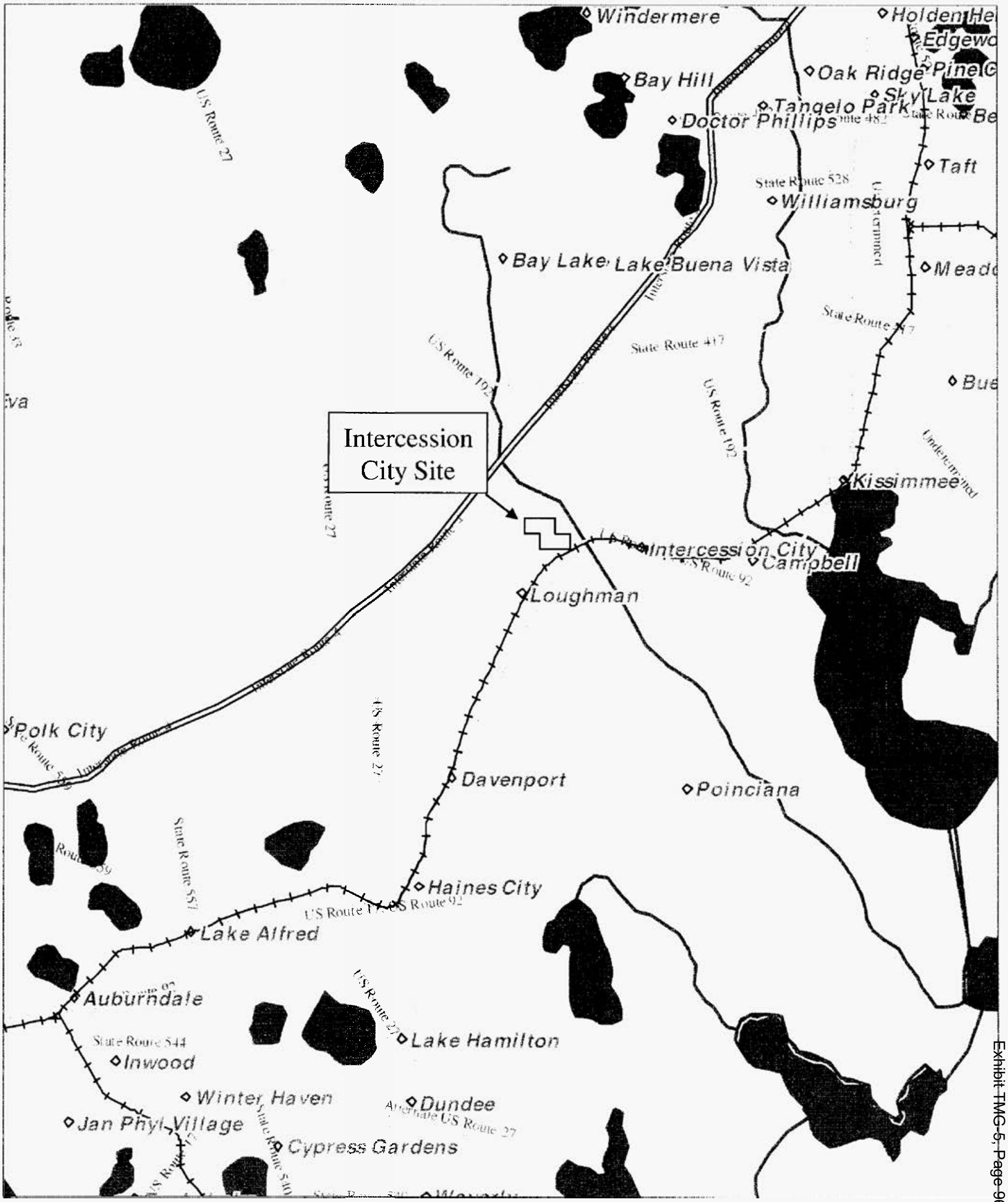
The Intercession City site (Figure 4.2) consists of 162 acres in Osceola County, two miles west of Intercession City. The site is immediately west of Reedy Creek and the adjacent Reedy Creek Swamp. The site is adjacent to a secondary effluent pipeline from a municipal wastewater treatment plant, an oil pipeline, and natural gas supply from the Florida Gas Transmission (FGT) and Gulfstream pipelines.

The Florida Department of Environmental Protection air rules currently list all of Osceola County as attainment for ambient air quality standards. The environmental impact on the site will be minimized by PEF's close coordination with regulatory agencies to ensure compliance with all applicable environmental regulations.

Transmission modifications will be required to accommodate additional combustion turbine peaking units at this site.

FIGURE 4.2

Intercession City Site (Osceola County)



Docket No. 20240013-EG
PEF 2005 Ten-Year Site Plan
Exhibit TMG-5, Page 96 of 102

DEBARY SITE

DeBary was chosen as a potential site for installation of peaking combustion turbine units.

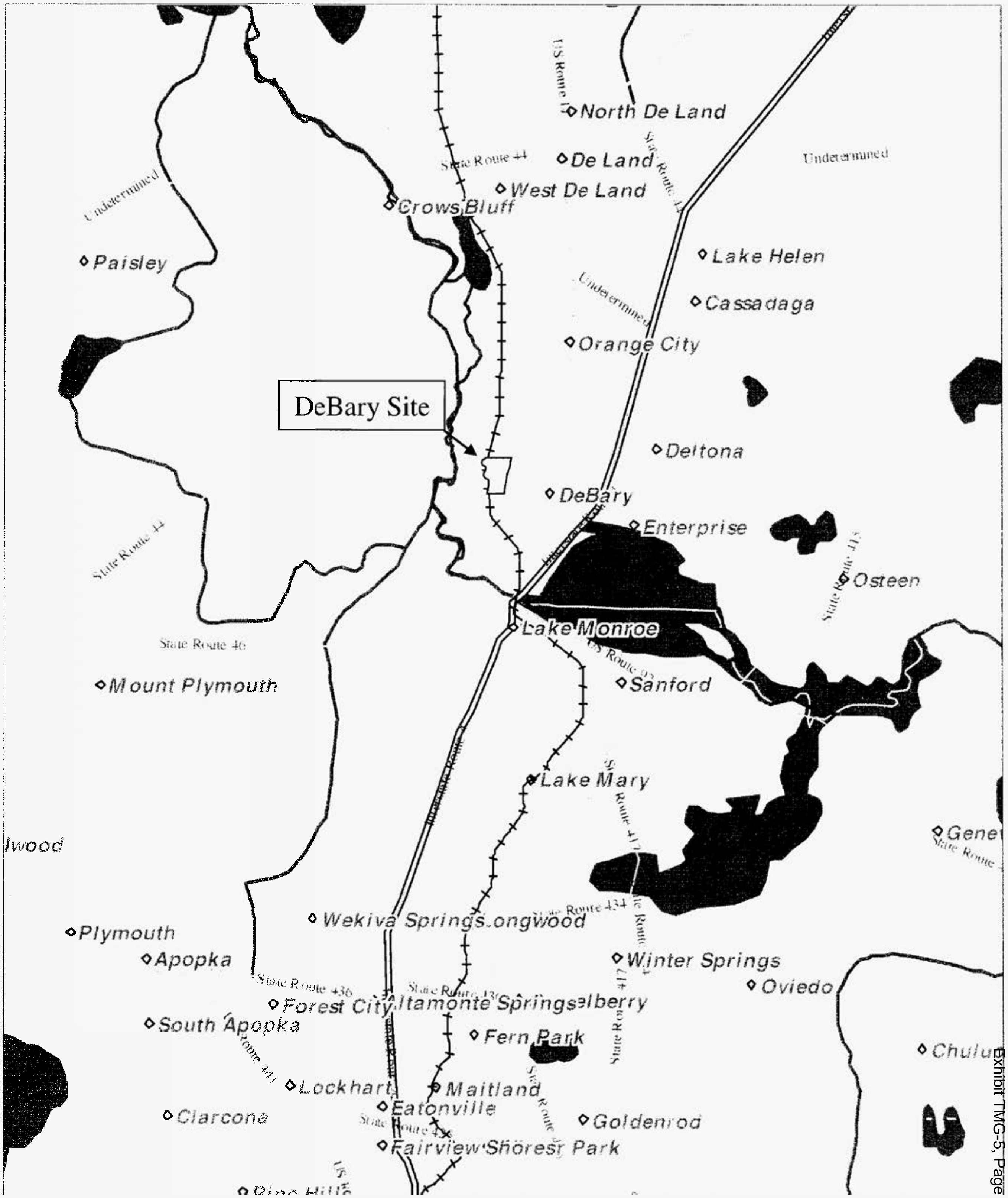
The DeBary site (Figure 4.3) consists of 2,210 acres in Volusia County, immediately west of the town of DeBary. The site is bordered on the west by the St. Johns River and on the north by Blue Springs State Park. This site is adjacent to an oil pipeline and natural gas supply from the Florida Gas Transmission (FGT) pipeline.

The Florida Department of Environmental Protection air rules currently list all of Volusia County as attainment for ambient air quality standards. The environmental impact on the site will be minimized by PEF's close coordination with regulatory agencies to ensure compliance with all applicable environmental regulations.

Transmission modifications will be required to accommodate additional combustion turbine peaking units at this site.

FIGURE 4.3

DeBary Site (Volusia County)



ANCLOTE SITE

Anclote was chosen as a potential site for installation of peaking combustion turbine units.

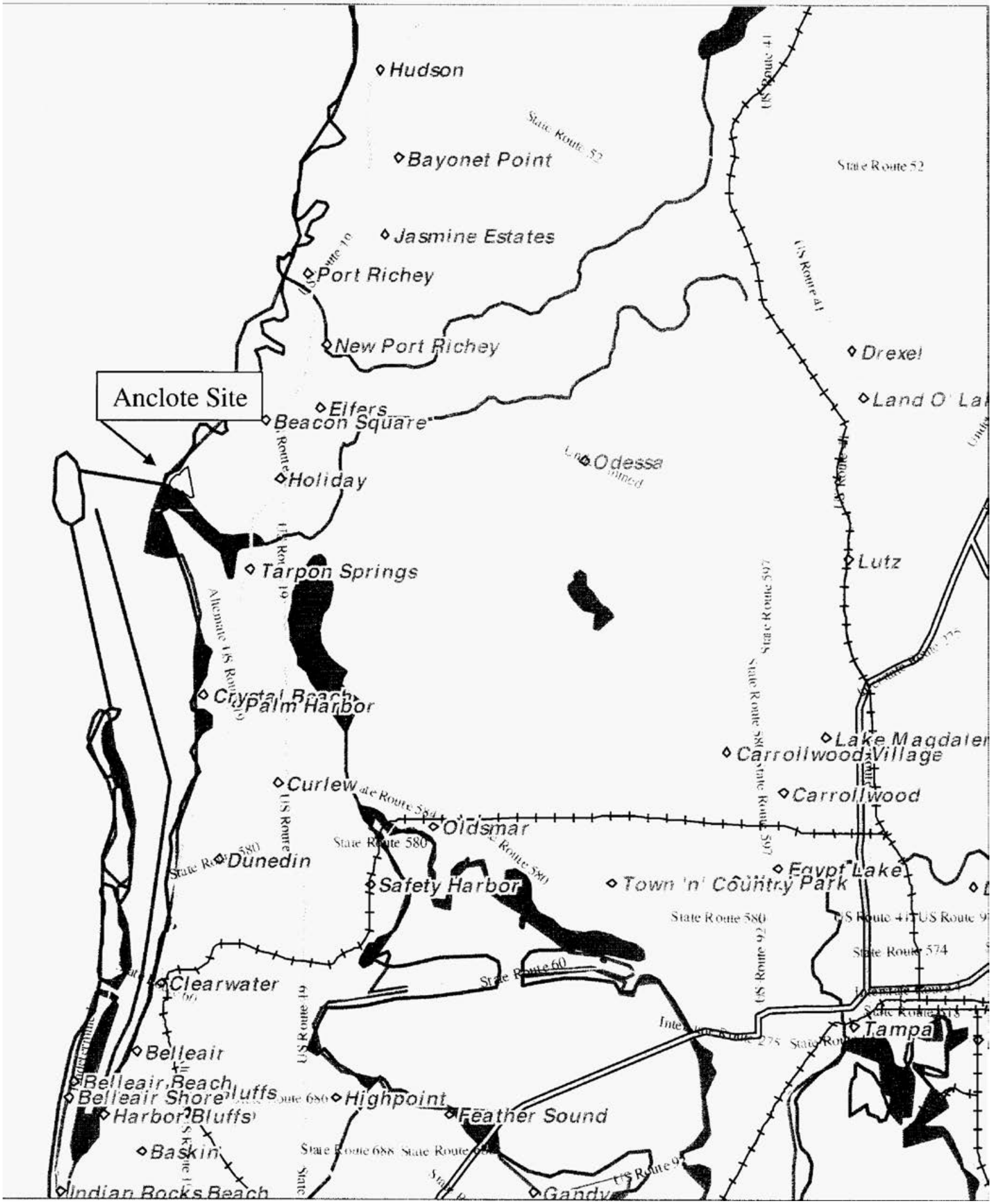
The Anclote site (Figure 4.4) consists of approximately 400 acres in Pasco County. The site is located in Holiday Florida at the mouth of the Anclote River. The site receives make-up water from the city of Tarpon Springs, fuel oil through a pipeline from the Bartow plant, and natural gas supply from the Florida Gas Transmission (FGT) pipeline.

The Florida Department of Environmental Protection air rules currently list all of Pasco County as attainment for ambient air quality standards. The environmental impact on the site will be minimized by PEF's close coordination with regulatory agencies to ensure compliance with all applicable environmental regulations.

Transmission modifications will be required to accommodate additional combustion turbine peaking units at this site.

FIGURE 4.4

Anclote (Pasco County)



BARTOW SITE

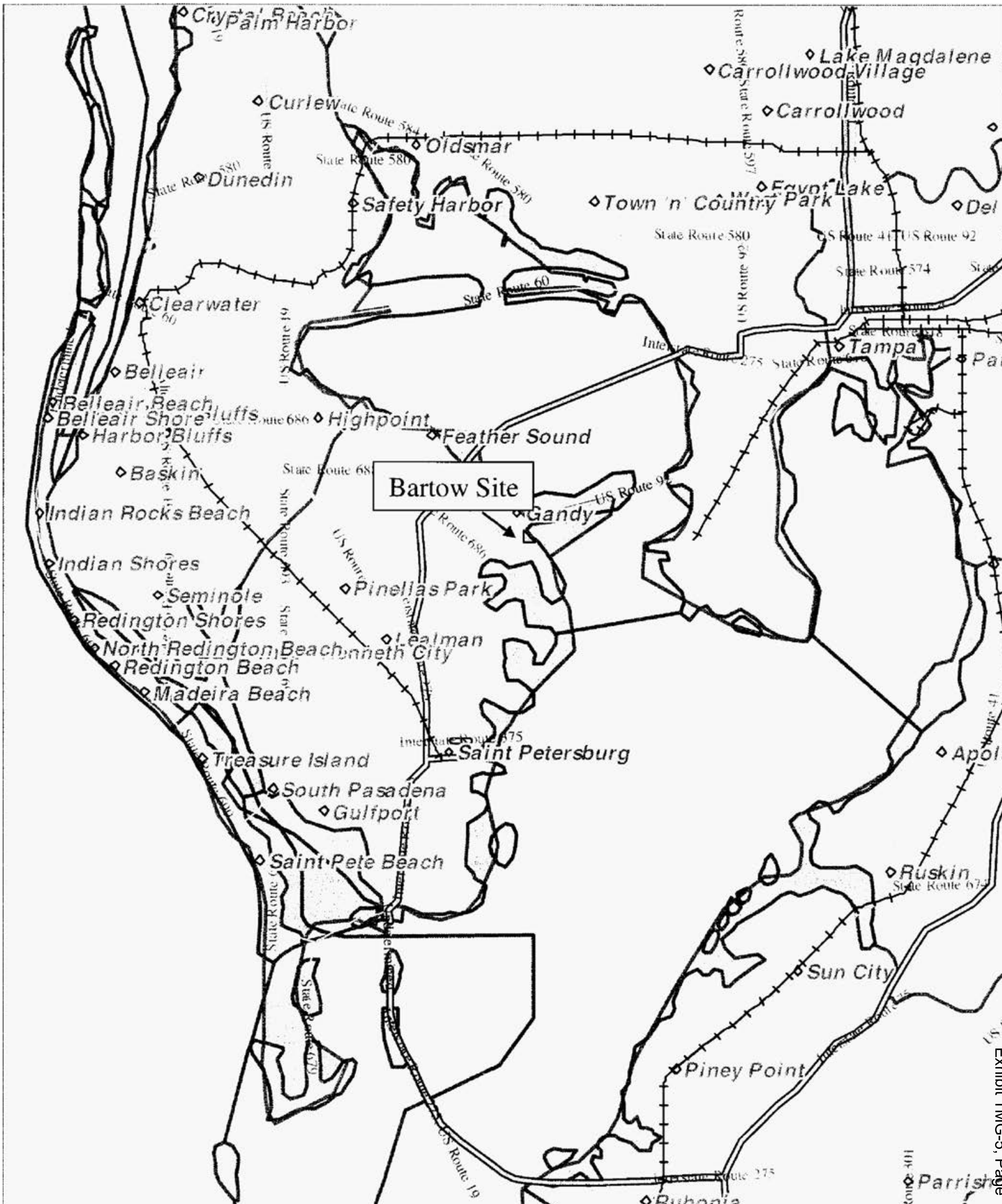
Bartow was chosen as a potential site for additional generation.

The Bartow site (Figure 4.5) consists of 1348 acres in Pinellas County, on the west shore of Tampa Bay. The site is on Weedon Island, north of downtown St. Petersburg. The site is adjacent to a barge fuel oil off-loading facility and natural gas supply from the Florida Gas Transmission (FGT) pipeline.

The Florida Department of Environmental Protection air rules currently list all of Pinellas County as attainment for ambient air quality standards. The environmental impact on the site will be minimized by PEF's close coordination with regulatory agencies to ensure compliance with all applicable environmental regulations.

Transmission modifications will be required to accommodate the potential repowering of existing Bartow steam units.

FIGURE 4.5
Bartow Site (Pinellas County)



Docket No. 20240013-EG
PEF 2005 Ten-Year Site Plan
Exhibit TMG-5, Page 102 of 102