State of Florida

Public Service Commission

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

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

DATE: November 4, 2020

TO: Division of Accounting and Finance, Office of Primary Responsibility

FROM: OFFICE OF COMMISSION CLERK

RE: CONFIDENTIALITY OF CERTAIN INFORMATION

DOCKET NOS: 20200001-EI   DOCUMENT NO: 11636-2020

DESCRIPTION: TECO (Beasley) - (CONFIDENTIAL) Highlighted information in Forms 423-2, 2(a), and 2(b) for 6/20; and Forms 423-1, 1(a), 2, 2(a), and 2(b) for 7/20.

SOURCE: **Tampa Electric Company**

The above confidential material was filed along with a request for confidential classification. Please complete the following form by checking all applicable information and forward it to the attorney assigned to the docket, along with a brief memorandum supporting your recommendation.

___ The document(s) is (are), in fact, what the utility asserts it (them) to be.
_X_ The utility has provided enough details to perform a reasoned analysis of its request.
___ The material has been received incident to an inquiry.
_X_ The material is confidential business information because it includes:
- ___ (a) Trade secrets;
- ___ (b) Internal auditing controls and reports of internal auditors;
- ___ (c) Security measures, systems, or procedures;
- _X_ (d) Information concerning bids or other contractual data, the disclosure of which would impair the efforts of the public utility or its affiliates to contract for goods or services on favorable terms;
- ___ (e) Information relating to competitive interests, the disclosure of which would impair the competitive business of the provider of information;
- ___ (f) Employee personnel information unrelated to compensation, duties, qualifications, or responsibilities;

_X_ The material appears to be confidential in nature and harm to the company or its ratepayers will result from public disclosure.
___ The material appears not to be confidential in nature.
_X_ The material is a periodic or recurring filing and each filing contains confidential information.

This response was prepared by /s/Devlin Higgins on 11.4.20, a copy of which has been sent to the Office of Commission Clerk and the Office of General Counsel.

State of Florida

Public Service Commission

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

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

DATE: November 4, 2020

TO: Suzanne S. Brownless, Special Counsel, Office of the General Counsel

FROM: Devlin Higgins, Public Utility Analyst IV, Division of Accounting & Finance

RE: CONFIDENTIALITY OF CERTAIN INFORMATION

DOCKET NO: 20200001-EI DOCUMENT NO: 11636-2020

TECO (Beasley) - (CONFIDENTIAL) Highlighted information in Forms 423-2, 2(a), and 2(b) for 6/20; and Forms 423-1, 1(a), 2, 2(a), and 2(b) for 7/20.

SOURCE: Tampa Electric Company

Pursuant to Section 366.093, Florida Statues (F.S.), and Rule 25-22.006, Florida Administrative Code, Tampa Electric Company (TECO or Company) requests confidential classification of certain information filed in the above-referenced docket, dated October 30, 2020.

The Company is claiming confidentiality of its information under Section 366.093(3)(d), F.S. Per the Statute, propriety of confidential business information includes, but is not limited to: Subsection (d) "[i]nformation concerning bids or other contractual data, the disclosure of which would impair the efforts of the public utility or its affiliates to contract for goods or services on favorable terms."

More specifically, the information at issue relates to actual purchase amounts pursuant to confidential contracts negotiated by and between the Company and certain energy providers. As such, the relevant information if disclosed would impair the efforts of TECO to contract for goods and services on favorable terms. This information has historically been treated as confidential. Further, TECO requests that the information for which the Company seeks confidential classification not be declassified until 24 months after the issuance of a Commission order disposing of this request. The Company claims this time period is necessary to allow it to negotiate future contracts without its competitors having access to information which would adversely affect the ability of TECO to negotiate future contracts.

Staff has reviewed the Company's confidentiality request. It is staff's opinion that the information subject to this request meets the criteria for confidentiality contained in Section 366.093(3)(d), F.S.

BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

In the Matter of:

DOCKET NO. 20200001-EI

FUEL AND PURCHASED POWER
COST RECOVERY CLAUSE WITH
GENERATING PERFORMANCE
INCENTIVE FACTOR.
_____________________________/

VOLUME 1
PAGES 1 through 248

PROCEEDINGS: HEARING

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

DATE: Tuesday, November 3, 2020

TIME: Commenced: 10:20 a.m.
Concluded: 5:12 p.m.

PLACE: Betty Easley Conference Center
Room 148
4075 Esplanade Way
Tallahassee, Florida

REPORTED BY: DEBRA R. KRICK
Court Reporter

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

APPEARANCES:

MATTHEW R. BERNIER, ESQUIRE, 106 East College Avenue, Suite 800, Tallahassee, Florida 32301-7740; and DIANNE M. TRIPLETT, ESQUIRE, 299 First Avenue North, St. Petersburg, Florida 33701, appearing on behalf of Duke Energy Florida, LLC.

MARIA J. MONCADA, WADE R. LITCHFIELD, and DAVID M. LEE, ESQUIRES, 700 Universe Boulevard, Juno Beach, Florida 33408-0420, appearing on behalf of Florida Power & Light Company.

BETH KEATING, ESQUIRE, Gunster, Yoakley & Stewart, P.A., 215 South Monroe Street, Suite 601, Tallahassee, Florida 32301-1839, appearing on behalf of Florida Public Utilities Company.

RUSSELL A. BADDERS, ESQUIRE, One Energy Place, Pensacola, Florida 32520-0100; MARIA J. MONCADA, ESQUIRE, 700 Universe Boulevard, Juno Beach, Florida 33408-0420, appearing on behalf of Gulf Power Company.

JAMES D. BEASLEY, J. JEFFRY WAHLEN, and MALCOLM N. MEANS, ESQUIRES, Ausley & McMullen, Post Office Box 391, Tallahassee, Florida 32302, appearing on behalf of Tampa Electric Company.

APPEARANCES (CONTINUED):

J.R. KELLY, PUBLIC COUNSEL; CHARLES REHWINKEL, DEPUTY PUBLIC COUNSEL; and PATRICIA A. CHRISTENSEN, STEPHANIE A. MORSE, A. MIREILLE FALL-FRY, and THOMAS (TAD) DAVID, ESQUIRES, Office of Public Counsel, c/o The Florida Legislature, 111 W. Madison Street, Room 812, Tallahassee, Florida 32399-1400, appearing on behalf of the Citizens of the State of Florida.

JON C. MOYLE, JR., and KAREN A. PUTNAL, ESQUIRES, Moyle Law Firm, P.A., The Perkins House, 118 North Gadsden Street, Tallahassee, Florida 32301, appearing on behalf of Florida Industrial Power Users Group.

JAMES W. BREW and LAURA WYNN BAKER, ESQUIRES, Stone Mattheis Xenopoulos & Brew, PC, 1025 Thomas Jefferson Street, NW, Eighth Floor, West Tower, Washington, DC 20007, appearing on behalf of White Springs Agricultural Chemicals, Inc. d/b/a PCS Phosphate - White Springs.

SUZANNE BROWNLESS, ESQUIRE, FPSC General Counsel's Office, 2540 Shumard Oak Boulevard, Tallahassee, Florida 32399-0850, appearing on behalf of the Florida Public Service Commission Staff.

APPEARANCES (CONTINUED):

KEITH HETRICK, GENERAL COUNSEL; MARY ANNE HELTON, DEPUTY GENERAL COUNSEL, ESQUIRES, Florida Public Service Commission, 2540 Shumard Oak Boulevard, Tallahassee, Florida 32399-0850, Advisor to the Florida Public Service Commission.

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P R O C E E D I N G S

CHAIRMAN CLARK: All right. Good morning again. We are going to call the November 3rd clause docket hearing to order.

I would ask staff, if they would, please read the notice.

MS. WEISENFELD: By notice issued on October 7th, 2020, this time and place has been set for hearings in Docket Nos. 20200001-EI, 20200002-EG, 20200003-GU, 20200004-GU and 20200007-EI. The purpose of these hearings is set out more fully in the notice.

CHAIRMAN CLARK: All right. Thank you, Ms. Weisenfeld.

Let me just give kind of a quick overview of what I think -- how I think things are going to go today.

We had scheduled this for today, tomorrow and Thursday. It looks like we are going to be able to consolidate things pretty rapidly. We are not going to try to rush anything through, but my plan this morning is to get through the first -- the 02, 03, 04 and 07 dockets even prior to lunch today.

If the timing hits us right, we are going to take a lunch break at 12 o'clock. We are going to probably take about 45 minutes for lunch. Those of you that are sitting at your kitchen table, it should not be too difficult for you to grab a quick sandwich, but the rest of us have got to go out and scrape something up. So we are going to probably take about 45 minutes for lunch. Then we will come back, and if we don't get to the 01 prior to lunch, we will take it up immediately after.

My anticipation, based on the number of witnesses and what we have seen so far, is that we are going to try to finish it up today. If it doesn't look like it's going to push much past 5:00 p.m., we will stay and wrap everything up today. If it does look like it's going to go quite a bit further, then we certainly have tomorrow scheduled, and we will reconvene tomorrow morning. Maybe we can make a little bit better call on that issue somewhere around 3:30 or four o'clock this afternoon.

So with that said, we are going to take appearances with all of the dockets to begin with.

Ms. Weisenfeld.

MS. WEISENFELD: There are five dockets to address today. We suggest that all appearances be taken at once.

All parties should enter their appearances and declare the dockets that they are entering an appearance for. Several parties will make appearances, and after the parties make their appearances, staff will need to make theirs.

CHAIRMAN CLARK: All right. Thank you.

All right. So we are going to take appearances beginning with Florida Power & Light. If you would, please state the docket that you are going to be appearing in when you give your appearance, please.

FPL.

MS. MONCADA: Good morning, Mr. Chairman. Can you hear me?

CHAIRMAN CLARK: Yes, we can hear you.

MS. MONCADA: Wonderful.

Maria Moncada on behalf of Florida Power & Light Company in the 01, 02 and 07 dockets. In each of those dockets, I would like to also enter an appearance for our general counsel, Wade Litchfield. In the 01 and 07 dockets, I will also enter an appearance for David Lee, and in the 02 docket, for Joel Baker.

Mr. Chairman, I am also here today on behalf of Gulf Power Company in the 01 and the 07 dockets.

And in those two dockets, I would like to also enter an appearance for Russell Badders.
Thank you.
CHAIRMAN CLARK: All right. Any other -- any other appearances for Gulf Power?
MR. GRIFFIN: Yes, Mr. Chairman. Thank you. Good morning, Commissioners.
This is Steven Griffin with the Beggs & Lane law firm in Pensacola. I will be entering an appearance for Gulf Power Company in the 02 docket, and would also like to enter an appearance for Russell Badders with Gulf Power Company in the 02 docket as well.
Thank you.
CHAIRMAN CLARK: All right. Thank you very much.
Duke Energy, Mr. Bernier.
MR. BERNIER: Good morning, Mr. Chairman, Commissioners. Matt Bernier from Duke Energy. I will be appearing in the 01, 02 and 07 dockets. I would also like to enter an appearance for Dianne Triplett in the same dockets.
Thank you.
CHAIRMAN CLARK: Thank you very much.
TECO.

MR. MEANS: Good morning, Mr. Chairman, Commissioners. This is Malcolm Means with the Ausley McMullen law firm in Tallahassee. I would also like to enter appearances for Jim Beasley and Jeff Wahlen with the Ausley McMullen law firm. We are appearing on behalf of Tampa Electric in the 02, 07 and 01 dockets.

Thank you.

CHAIRMAN CLARK: Thank you very much.

Florida Public Utilities, Ms. Keating.

MS. KEATING: Good morning, Mr. Chairman, Commissioners. Beth Keating with the Gunster Law Firm appearing today on behalf of FPUC in the 01, 02, 03 and 04 dockets. I will also be making an appearance for Chesapeake and Sebring in the 04 docket, and I will also be appearing for Florida City Gas in the 03 and 04 dockets. And in those dockets, I would like to also enter appearance for Greg Munson with the Gunster Law Firm, as well as Chris Wright with FPL.

CHAIRMAN CLARK: All right. Thank you very much.

That takes care of Florida City Gas and Sebring Gas. Anybody else under those two?

All right moving to Peoples Gas.

MR. BROWN: Thank you, Mr. Chairman, Andy Brown of the law firm of Macfarlane Ferguson & McMullen. I am appearing on behalf of Peoples Gas in the 03 and 04 dockets.

CHAIRMAN CLARK: All right. St. Joe Natural Gas Company. They were requested to be excused? Okay.

MS. WEISENFELD: They should be on the line. They should be on the line. St. Joe should be on the line, Mr. Chairman.

CHAIRMAN CLARK: Okay. Is there anyone from St. Joe? Anyone from St. Joe? Stuart Shoaf?

All right. Move right along to the Office of Public Counsel.

MS. FALL-FRY: Good morning. A. Mireille Fall-Fry. I will be appearing for the Office of Public Counsel in the 02, 03, 04 and 07 dockets, and also would like to enter an appearance for Charles Rehwinkel and Stephanie Morse in the 01 docket, and J.R. Kelly in all of the dockets.

CHAIRMAN CLARK: All right. Thank you, Ms. Fall-Fry.

FIPUG.

MS. PUTNAL: Good morning, Mr. Chairman, Commissioners. Karen Putnal with the Moyle Law

Firm appearing on behalf of Florida Industrial Power Users Group in the 01, 02 and 07 dockets. And I would also like to enter an appearance for Jon Moyle in all three.

CHAIRMAN CLARK: All right. Thank you, Ms. Putnal.

PCS Phosphate.

MR. BREW: Good morning, Chairman and Commissioners. For White Springs Agricultural Chemicals, PCS Phosphate, with the law firm of Stone Mattheis Xenopoulos & Brew, in the 01, 02 and 07 dockets, I am James Brew, and I would like to note the appearance of Laura Baker and as well.

CHAIRMAN CLARK: All right. Great. Thank you very much, Mr. Brew.

Commission staff.

MS. WEISENFELD: Ashley Weisenfeld in the 02 docket. I would also like to enter appearances for Kurt Schrader in the 03, Gabriella Passidomo in the 04, Charles Murphy in the 07 and Suzanne Brownless in the 01.

MS. HELTON: And finally, Mr. Chairman, Mary Anne Helton is here as your Advisor today, as well as for the other Commissioners, along with your General Counsel, Keith Hetrick.

CHAIRMAN CLARK: Thank you, Ms. Helton.

Okay, let's move to preliminary matters, Ms. Weisenfeld.

MS. WEISENFELD: State buildings are currently closed to the public, and other restrictions on gatherings remain in place due to COVID-19. Accordingly, this hearing is being conducted remotely with the parties participating by communications media technology.

Members of the public who want to observe or listen to this hearing may do so by accessing the live video broadcast which is available from the Commission website. Upon completion of the hearing, the archived video will also be available.

Each person participating today needs to keep their phone or device muted when they are not speaking, and only unmute when they are called upon to speak. If they do not keep their phone muted, or put their phone on hold, they may be disconnected from the proceeding and will need to call back in.

Also, telephonic participants should speak directly into their phone and not use their speaker function.

CHAIRMAN CLARK: All right. Thank you, Ms.

Weisenfeld.

All right. The order of the dockets we are going to take up today, we are going to begin with the 02 docket, the 03, the 04 and the 07, and then we will conclude the day with the 01 docket.

(Whereupon, other matters were held before the Commission, and Docket No. 20200001-EI proceedings are as follows:)

CHAIRMAN CLARK: All right. We are going to open the 01 docket. I assume all the parties are on the line and, staff, are there preliminary matters?

MS. BROWNLESS: Yes, sir.

There are proposed Type 2 stipulations for all of FPUC, Gulf and TECO issues listed in the Prehearing Order, Section X, on pages 37 through 56. For FPUC Issue 3A, stated on page 11 of the Prehearing Order, there is no corresponding stipulated stated since it was inadvertently admitted. The parties have agreed to the following:

Issue 3A, should the Commission approve FPUC's revised fuel and purchase power cost recovery factors filed in accordance with the stipulation and settlement approved in Docket No.

201980156-EI -- actually, it's probably 20190156-EI -- which reflect the flow-through of interim rate overrecovery calculated based on nine months actual and one month estimated revenue? The stipulation is yes.

There are proposed Type 2 stipulations for the following Florida Power & Light issues: 2A, 2B, 2C, 2D, 2E, 2H, 6, 7, 11, 16, 17, 19, 21, 24A, 24B, 27, 28, 29, 30, 31, 32, 33, 34, 35 and 36. These are contained in the Prehearing Order, Section X, pages 37 through 56 as well.

FPL's Issues 2F, 2G, 8, 9, 10, 18, 20 and 22 are outstanding.

There are no proposed Type 2 stipulations for any of DEF's issues: Issues 1A, 6 through 11, 16 through 22, 23A through 23D, 27 through 33 and 34 through 36. These are contained in the Prehearing Order, Section VIII, on pages seven through 32.

The issues for which there are type -- there are proposed Type 2 stipulations can be voted on today.

Finally, yesterday, DEF filed an appeal and motion for stay of the Commission's order adopting Judge Stevenson's Recommended Order regarding Bartow Unit 4 replacement power costs. This motion will be dealt with at the Commission's December 1st agenda conference.

And that's all, sir.

CHAIRMAN CLARK: Thank you very much, Ms. Brownless.

Okay, let's address prefiled testimony.

MS. BROWNLESS: Thank you.

It is our understanding that the following witnesses have been excused, and the prefiled testimonies of McClay, Lewter, Deaton, Yupp, Rote, Fuentes, Anderson, Young, Cutshaw, Hume, Sizemore, Cain, Smith, Heisey and Dobiac have been stipulated to by the parties.

We would ask that the prefiled testimony of these witnesses be moved into the record at this time.

CHAIRMAN CLARK: Without objection, the prefiled testimony is moved into the record.

(Whereupon, prefiled direct testimony of James McClay was inserted.)

DUKE ENERGY FLORIDA

DOCKET NO. 20200001-EI

Fuel and Capacity Cost Recovery
Final True-Up for the Period
January through December 2019

DIRECT TESTIMONY OF
JAMES MCCLAY

April 3, 2020

Q. Please state your name and business address.

A. My name is James McClay. My business address is 526 South Church Street, Charlotte, North Carolina 28202.

Q. By whom are you employed and in what capacity?

A. I employed by Duke Energy Carolinas ("DEC"), an affiliate company of Duke Energy Florida, LLC ("DEF", "Petitioner" or "Company") as the Director of Trading. I manage the Southeast power trading, Midwest financial activities, oil procurement and natural gas group procurement, scheduling and hedging activities in the Trading and Dispatch Section of the Fuels and Systems Optimization Department for the Duke Energy regulated generation fleet. This group is responsible for the hourly trading, financial hedging activities, oil procurement and natural gas procurement and scheduling needed to support the gas generation needs for Duke Energy Indiana, Duke Energy

Kentucky, Duke Energy Carolinas, Duke Energy Progress and Duke Energy Florida.

Q. Have you testified before the Commission in previous fuel clause proceedings?

A. Yes.

Q. Please briefly describe your work experience.

A. I received a Bachelor Degree in Business Administration majoring in Finance from St. Bonaventure University. I joined Progress Energy in 1998 as the Manager of Power Trading and held that position through early 2003 and then became the Director of Power Trading and Portfolio Management for Progress Energy Ventures through February 2007. From March 2007 through late 2008, I was the Director of Power Trading for Arclight Energy Marketing. From March 2009 through present I've been either the Director of Trading, Director of Natural Gas or the Manager of Gas and Oil Trading with Progress Energy and Duke Energy. Prior to my tenure with Duke Energy, I spent approximately 13 years in Capital Markets as a U.S. Government fixed income securities trader with various banks, and primary broker/ dealers.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to provide the August through December 2019 hedging true-up data and summarize the results of DEF's hedging activity for calendar year 2019 as required by Commission Order No. PSC-02-1484-

FOF-EI and further clarified by Commission Orders No. PSC-08-0667-PPA-EI issued in October 2008, and No. PSC-09-0255-PAA-EI issued in April 2009.

Q. Have you prepared exhibits to your testimony?

A. No. To clarify, DEF does not have any hedges in place past March 2019 - therefore there are no results to report for August through December of 2019.

Q. What are the objectives of DEF's hedging strategy?

A. The objectives of DEF's hedging program are to reduce fuel price volatility risk and provide greater cost certainty for DEF's customers.

Q. What hedging activities did DEF undertake for 2019 and what were the results?

A. As discussed below, DEF did not execute any hedges during 2019. Prior hedging activities resulted in a net hedge savings for 2019 of approximately $100,700.

Q. Did DEF execute its hedging activities consistent with its approved Risk Management Plan?

A. As part of the Joint Stipulation and Agreement for Interim Resolution of Hedging Issues filed on October 24, 2016 in Docket No. 20160001-EI, DEF ceased hedging activities. Subsequently, DEF agreed to a hedging moratorium during the term of the 2017 Second Revised and Restated

Stipulation and Settlement Agreement, approved by the Commission in Docket No. 20170183-EI. Notwithstanding the suspension of prospective hedging activities, DEF had hedging transactions entered into under previously approved risk management plans that settled in 2019.

As outlined in those earlier Commission-approved plans, actual hedge percentages for any monthly period, rolling twelve month time period or calendar annual period can come in higher or lower than the hedge percentage targets as a result of actual versus forecasted fuel burns.

Q. Did DEF hedging activities meet the stated objective and are the activities consistent with the Commission's Orders for hedging?

A. Yes. DEF's hedging activity met the stated objective of DEF's hedging program to reduce price risk and provide greater cost certainty for DEF's customers. The hedging activities are consistent with Commission Orders No. PSC-02-1484-FOF-EI, No. PSC-08-0667-PPA-EI, and No. PSC-09-0255-PAA-EI. DEF's hedging activities are conducted in an environment of strong internal controls and executed in a structured manner. DEF's hedging activities do not attempt to outguess the market and may or may not result in net fuel cost savings, but have achieved the objectives of reduced fuel price volatility.

Q. Does this conclude your testimony?

A. Yes.

(Whereupon, prefiled direct testimony of Mary Ingle Lewter was inserted.)

DUKE ENERGY FLORIDA, LLC

DOCKET NO. 20200001-EI

GPIF Schedules for
January through December 2019

DIRECT TESTIMONY OF
MARY INGLE LEWTER

March 16, 2020

Q. Please state your name and business address.

A. My name is M. Ingle Lewter. My business address is 526 South Church Street, Charlotte, North Carolina 28202.

Q. By whom are you employed and in what capacity?

A. I am employed by Duke Energy Indiana, LLC ("DEI") as Manager of Fuels and Fleet Analytics for Fuels and Systems Optimization.

Q. Describe your responsibilities as Manager of Fuels and Fleet Analytics.

A. As Manager of Fuels and Fleet Analytics for Fuels and Systems Optimization, I oversee the analysis and modeling of energy portfolios for Duke Energy Corporation's regulated utility subsidiaries, including Duke Energy Florida, LLC ("DEF" or "Company"), as well as Duke Energy Carolinas ("DEC"), Duke Energy Progress, LLC ("DEP"), DEI, and Duke

Energy Kentucky, Inc ("DEK"). My responsibilities include oversight of planning and coordination associated with economic system operations, including production cost modeling, outage coordination, dispatch pricing, fuel burn forecasting, position analysis, and commodities analytics.

Q. Please describe your educational background and professional experience.

A. I earned a Bachelor of Science in Statistics from North Carolina State University in 1995. I have worked with Progress Energy (Carolina Power & Light) and Duke Energy combined since graduating from North Carolina State University in 1995. I started with Carolina Power & Light (CP&L) in the customer service area and then moved into payroll services in 1997. In 1999, I joined the Bulk Power Marketing Department as a Business Analyst and was responsible for data analysis, including load forecast metrics, external market tracking and unit commitment modeling. In 2000, I took the role of Power Scheduler and was responsible for scheduling, confirming and tagging all short-term physical power transactions. In 2005, I was promoted to Portfolio Analyst in the Portfolio Management group. In this role, I was responsible for the short-term seven-day unit commitment plan for Progress Energy Florida, which included load forecast development, generation scheduling, unit commitment and the fuel burn forecast. In 2008, I moved from the short-term seven-day unit commitment responsibilities to the mid-term forecasting role and was promoted to Senior Portfolio Analyst. In 2012, I was promoted to Lead Fuels & Fleet Analyst when Progress Energy merged with Duke Energy. In these roles, I was responsible for the 5-year mid-term forecast for Duke Energy Carolinas and Duke Energy Midwest utilities, which are utilized for fuel planning, regulatory fuel filings, and budget development. In December 2019, I became the Manager of Fuels & Fleet Analytics, which is responsible for the mid-term forecast for all Duke Energy Jurisdictions (DEC, DEP, DEI, DEK, and DEF).

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to describe the calculation of DEF's Generating Performance Incentive Factor ("GPIF") reward/(penalty) amount for the period of January through December 2019. This calculation was based on a comparison of the actual performance of DEF's Seven (7) GPIF generating units for this period against the approved targets set for these units prior to the actual performance period.

Q. Do you have an exhibit to your testimony in this proceeding?

A. Yes, I am sponsoring Exhibit No. _______ (MIL-1T), which consists of the schedules required by the GPIF Implementation Manual to support the development of the incentive amount. This 24-page exhibit is attached to my prepared testimony and includes as its first page an index to the contents of the exhibit.

Q. What GPIF incentive amount has been calculated for this period?

A. DEF's calculated GPIF incentive amount is a reward of $4,407,712. This amount was developed in a manner consistent with the GPIF Implementation Manual. Page 2 of my exhibit shows the system GPIF points and the corresponding reward/(penalty). The summary of weighted incentive points earned by each individual unit can be found on page 4 of my exhibit.

Q. How were the incentive points for equivalent availability and heat rate calculated for the individual GPIF units?

A. The calculation of incentive points was made by comparing the adjusted actual performance data for equivalent availability and heat rate to the target performance indicators for each unit. This comparison is shown on each unit's Generating Performance Incentive Points Table found on pages 9 through 15 of my exhibit.

Q. Why is it necessary to make adjustments to the actual performance data for comparison with the targets?

A. Adjustments to the actual equivalent availability and heat rate data are necessary to allow their comparison with the "target" Point Tables exactly as approved by the Commission prior to the period. These adjustments are described in the Implementation Manual and are further explained by a Staff memorandum, dated October 23, 1981, directed to the GPIF utilities. The adjustments to actual equivalent availability primarily concern the differences between target and actual planned outage hours, and are shown on page 7 of my exhibit. The heat rate adjustments concern the differences between the target and actual Net Output Factor (NOF), and are shown on page 8. The methodology for both the equivalent availability and heat rate adjustments are explained in the Staff memorandum.

In addition, the Bartow combined cycle (“CC”) unit had data excluded during the period in which its steam turbine was in a planned outage. The Bartow CC unit has the capability to be operated in simple cycle mode while the steam turbine is in an outage. When operating in simple cycle mode, the unit’s heat rate will deviate significantly from its normal range. DEF’s heat rate target setting process for the Bartow CC unit excludes historical data from periods when the unit operated in simple cycle mode. From late September until early December 2019 the steam turbine was in a planned outage; during this period the Bartow CC unit was operated in simple cycle mode when the combustion turbines ("CT") were available. To be consistent with the target setting process, simple cycle mode heat rate data was excluded from actuals for the purposes of calculating the heat rate for the Bartow CC in year 2019 during those times when the unit was being operated in simple cycle mode as the result of a planned outage.

Q. Have you provided the as-worked planned outage schedules for DEF’s GPIF units to support your adjustments to actual equivalent availability?

A. Yes. Page 23 of my exhibit summarizes the planned outages experienced by DEF’s GPIF units during the period. Page 24 presents an as-worked schedule for each individual planned outage.

Q. Does this conclude your testimony?

A. Yes.

IN RE: PETITION ON BEHALF OF DUKE ENERGY FLORIDA FOR FUEL AND CAPACITY COST RECOVERY FINAL TRUE-UP FOR THE PERIOD JANUARY THROUGH DECEMBER 2019

FPSC DOCKET NO. 20200001-EI

GPIF TARGETS AND RANGES FOR JANUARY THROUGH DECEMBER 2021

DIRECT TESTIMONY OF MARY INGLE LEWTER

September 3, 2020

Q. Please state your name and business address.

A. My name is M. Ingle Lewter. My business address is 526 South Church Street, Charlotte, North Carolina 28202.

Q. By whom are you employed and in what capacity?

A. I am employed by Duke Energy Indiana, LLC ("DEI") as Manager of Fuels and Fleet Analytics for Fuels and Systems Optimization. DEI and Duke Energy Florida, LLC ("DEF" or "Company") are both wholly-owned subsidiaries of Duke Energy Corporation ("Duke Energy").

Q. What are your responsibilities in that position?

A. As Manager of Fuels and Fleet Analytics for Fuels and Systems Optimization, I oversee the analysis and modeling of energy portfolios for Duke Energy Corporation's regulated utility subsidiaries, including Duke Energy Florida, LLC ("DEF" or "Company"), as well as Duke Energy Carolinas ("DEC"), Duke Energy Progress, LLC ("DEP"), DEI, and Duke

Energy Kentucky, Inc ("DEK"). My responsibilities include oversight of planning and coordination associated with economic system operations, including production cost modeling, outage coordination, dispatch pricing, fuel burn forecasting, position analysis, and commodities analytics.

Q. Please describe your educational background and professional experience.

A. I earned a Bachelor of Science in Statistics from North Carolina State University in 1995. I have worked with Progress Energy (Carolina Power & Light) and Duke Energy combined since graduating from North Carolina State University in 1995. I started with Carolina Power & Light (CP&L) in the customer service area and then moved into payroll services in 1997. In 1999, I joined the Bulk Power Marketing Department as a Business Analyst and was responsible for data analysis, including load forecast metrics, external market tracking and unit commitment modeling. In 2000, I took the role of Power Scheduler and was responsible for scheduling, confirming and tagging all short-term physical power transactions. In 2005, I was promoted to Portfolio Analyst in the Portfolio Management group. In this role, I was responsible for the short-term seven-day unit commitment plan for Progress Energy Florida, which included load forecast development, generation scheduling, unit commitment and the fuel burn forecast. In 2008, I moved from the short-term seven-day unit commitment responsibilities to the mid-term forecasting role and was promoted to Senior Portfolio Analyst. In 2012, I was promoted to Lead Fuels & Fleet Analyst when Progress Energy merged with Duke Energy. In these roles, I was responsible for the 5-year mid-term forecast for Duke Energy Carolinas and Duke Energy Midwest utilities, which are utilized for fuel planning, regulatory fuel filings, and budget development. In December 2019, I became the Manager of Fuels & Fleet Analytics, which is responsible for the mid-term forecast for all Duke Energy Jurisdictions (DEC, DEP, DEI, DEK, and DEF).

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to provide a recap of actual reward / penalty for the period of January through December 2019, and outline the development of the Company's Generating Performance Incentive Factor ("GPIF") targets and ranges for the period January through December 2021. These GPIF targets and ranges have been developed from individual unit equivalent availability, average net operating heat rate targets, and improvement/degradation ranges for each of the Company's GPIF generating units, in accordance with the Commission's GPIF Implementation Manual.

Q. What GPIF incentive amount was calculated and reported in your March 16, 2020 testimony for the period January through December 2019?

A. DEF's calculated GPIF incentive amount for this period was a reward of $4,407,712. Please refer to my testimony filed March 16, 2020 for the details of how this incentive amount was calculated.

Q. Have there been any adjustments to the incentive amount filed in March?

A. No.

Q. Do you have an exhibit to your testimony?

A. Yes. I am sponsoring Exhibit No. _____ (MIL-1P), which consists of the GPIF standard form schedules prescribed in the GPIF Implementation Manual and supporting data, including outage rates, net operating heat rates, and computer analyses and graphs for each of the individual GPIF units. This exhibit is attached to my prepared testimony and includes as its first page an index to the contents of the exhibit.

Q. Which of the Company's generating units have you included in the GPIF program for the upcoming projection period?

A. For the 2021 projection period, the GPIF program includes the following units: Bartow Unit 4, Crystal River Unit 4, Crystal River Unit 5, and Hines Units 1 through 4. Combined, these units account for 85% of the estimated total system net generation for the period, excluding Citrus CC units. Citrus CC Units 1 and 2 were not included for the upcoming projection period since they do not meet the inclusion of performance history to use in setting targets and ranges for these units.

Q. Have you determined the equivalent availability targets and improvement/degradation ranges for the Company's GPIF units?

A. Yes. This information is included in the GPIF Target and Range Summary on page 4 of my Exhibit No. ___ (MIL-1P).

Q. How were the equivalent availability targets developed?

A. The equivalent availability targets were developed using the methodology established for the Company's GPIF units, as set forth in Section 4 of the GPIF Implementation Manual. This includes the formulation of graphs based on each unit's historic performance data for the four individual unplanned outage rates (i.e., forced, partial forced, maintenance, and partial maintenance outage rates), which in combination constitute the unit's equivalent unplanned outage rate ("EUOR"). From operational data and these graphs, the individual target rates are determined through a review of three years of monthly data points. The unit's four target rates are then used to calculate its unplanned outage hours for the projection period. When the unit's projected planned outage hours are taken into account, the hours calculated from these individual unplanned outage rates can then be converted into an overall equivalent unplanned outage factor ("EUOF"). Because factors are additive (unlike rates), the EUOF and planned outage factor ("POF") when added to the equivalent availability factor ("EAF") will always equal 100%. For example, an EUOF of 15% and POF of 10% results in an EAF of 75%. The supporting tables and graphs for the target and range rates are contained in pages 41-76 of my exhibit in the section entitled "Unplanned Outage Rate Tables and Graphs."

Q. Please describe the methodology utilized to develop the improvement/degradation ranges for each GPIF unit's availability targets?

A. The methodology described in the GPIF Implementation Manual was used. Ranges were first established for each of the four unplanned outage rates associated with each unit. From an analysis of the unplanned outage graphs, units with small historical variations in outage rates were assigned narrow ranges and units with large variations were assigned wider ranges. These individual ranges, expressed in term of rates, were then converted into a single unit availability range, expressed in terms of a factor, using the same procedure described above for converting the availability targets from rates to factors.

Q. Were adjustments made to historical unit availability to account for significant anomalies in historical performance?

A. No.

Q. Have you determined the net operating heat rate targets and ranges for the Company's GPIF units?

A. Yes. This information is included in the Target and Range Summary on page 4 of my Exhibit No. ___ (MIL-1P).

Q. How were these heat rate targets and ranges developed?

A. The development of the heat rate targets and ranges for the upcoming period utilized historical data from the past three years, as described in the GPIF Implementation Manual. A "least squares" procedure was used to curve-fit the heat rate data to a linear relationship with Net Operating Factor (NOF), and ranges at a 90% confidence level were also established assuming a normal distribution. The analyses and data plots used to develop the heat rate targets and ranges for each of the GPIF units are contained in pages 26-40 of my exhibit in the section entitled "Average Net Operating Heat Rate Curves."

Q. How were the GPIF incentive points developed for the unit availability and heat rate ranges?

A. GPIF incentive points for availability and heat rate were developed by evenly spreading the positive and negative point values from the target to the maximum and minimum values in the case of availability, and from the neutral band to the maximum and minimum values in the case of heat rate. The fuel savings (loss) dollars were evenly spread over the range in the same manner as described for incentive points. The maximum savings (loss) dollars are the same as those used in the calculation of the weighting factors.

Q. How were the GPIF weighting factors determined?

A. To determine the weighting factors for availability, a series of simulations was made using a production costing model in which each unit's maximum equivalent availability was substituted for the target value to obtain a new system fuel cost. The differences in fuel costs between these cases and the target case determine the contribution of each unit's availability to fuel savings. The heat rate contribution of each unit to fuel savings was determined by multiplying the BTU savings between the minimum and target heat rates (at constant generation) by the average cost per BTU for that unit. Weighting factors were then calculated by dividing each individual unit's fuel savings by total system fuel savings.

Q. What was the basis for determining the estimated maximum incentive amount?

A. The determination of the maximum reward or penalty was based upon monthly common equity projections obtained from a detailed financial simulation performed by the Company's Corporate Model.

Q. What is the Company's estimated maximum incentive amount for 2021?

A. The estimated maximum incentive for the Company is $12,512,937. The calculation of the estimated maximum incentive is shown on page 3 of my Exhibit No. ___ (MIL-1P).

Q. Does this conclude your testimony?

A. Yes.

(Whereupon, prefiled direct testimony of Renae B. Deaton was inserted.)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF RENAE B. DEATON

DOCKET NO. 20200001-EI

MARCH 2, 2020

Q. Please state your name, business address, employer and position.

A. My name is Renae B. Deaton. My business address is 700 Universe Boulevard, Juno Beach, Florida 33408. I am employed by Florida Power & Light Company ("FPL" or "the Company") as the Director, Clause Recovery and Wholesale Rates, in the Regulatory & State Governmental Affairs Department.

Q. Please state your education and business experience.

A. I hold a Bachelor of Science in Business Administration and a Master of Business Administration from Charleston Southern University. Since joining FPL in 1998, I have held various positions in the rates and regulatory areas. Prior to my current position, I held the positions of Senior Manager of Cost of Service and Load Research and Senior Manager of Rate Design in the Rates and Tariffs Department. I am a member of the Edison Electric Institute ("EEI") Rates and Regulatory Affairs Committee, and I have completed the EEI Advanced Rate Design Course. I have been a guest speaker at Public Utility Research Center/World Bank International Training Programs on Utility Regulation and Strategy. In 2016, I assumed my current position, where my duties include providing direction as to appropriateness of inclusion of costs through a cost recovery clause and the overall preparation and filing of all cost recovery clause documents including testimony and discovery. As part of the various roles I have held with the Company, I have testified before this Commission in base rate and clause recovery proceedings.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to present the schedules necessary to support the actual Fuel Cost Recovery ("FCR") Clause and Capacity Cost Recovery ("CCR") Clause net true-up amounts for the period January 2019 through December 2019.

The 2019 net true-up for the FCR Clause is an under-recovery, including interest, of $51,531,817. FPL is requesting Commission approval to include this 2019 FCR Clause true-up under-recovery in the calculation of the FCR factors for the period January 2021 through December 2021.

The 2019 net true-up for the CCR Clause is an over-recovery, including interest, of $5,141,967. FPL is requesting Commission approval to include this 2019 CCR Clause true-up over-recovery in the calculation of the CCR factors for the period January 2021 through December 2021.

Finally, FPL is requesting Commission approval to include $9,149,588 in the calculation of the FCR factors for the period January 2021 through December 2021, which represents FPL's share of the 2019 Incentive Mechanism gains described in the testimony of FPL witness Yupp and presented on page 1 of Exhibit GJY-1.

Q. Have you prepared or caused to be prepared under your direction, supervision or control any exhibits in this proceeding?

A. Yes, I have. Exhibit RBD-1 contains the FCR-related schedules and Exhibit RBD-2 contains the CCR-related schedules. In addition, FCR Schedules A1 through A12 for the January 2019 through December 2019 period have been filed monthly with the Commission and served on all parties of record in this docket. Those schedules are incorporated herein by reference.

Q. What is the source of the data you present?

A. Unless otherwise indicated, the data are taken from the books and records of FPL. The books and records are kept in the regular course of the Company's business in accordance with generally accepted accounting principles and practices, and with the applicable provisions of the Uniform System of Accounts as prescribed by the Commission.

FUEL COST RECOVERY CLAUSE

Q. Please explain the calculation of the 2019 FCR net true-up amount.

A. Exhibit RBD-1, page 1, titled "Calculation of Net True-Up," shows the calculation of the FCR net true-up for the period January 2019 through December 2019, an under-recovery of $51,531,817.

The summary of the FCR net true-up amount shows the actual end-of-period true-up over-recovery for the period January 2019 through December 2019 of

$77,204,120 on line 1. The actual/estimated true-up over-recovery for the same period of $128,735,937 is shown on line 2. Line 1 less line 2 results in the net final true-up under-recovery for the period January 2019 through December 2019 of $51,531,817 shown on line 3.

The calculation of the FCR true-up amount for the period follows the procedures established by this Commission as set forth on Commission Schedule A2 "Calculation of True-Up and Interest Provision."

Q. Have you provided a schedule showing the calculation of the 2019 FCR actual true-up by month?

A. Yes. Exhibit RBD-1, page 2, titled "Calculation of Final True-Up Amount," shows the calculation of the FCR actual true-up by month for January 2019 through December 2019.

Q. Have you provided a schedule showing the variances between actual and actual/estimated FCR costs and applicable revenues for 2019?

A. Yes. Exhibit RBD-1, page 3, (sum of lines 39 and 40) compares the actual end-of-period true-up over-recovery of $77,204,120 (column 4) to the actual/estimated end-of-period true-up over-recovery of $128,735,937 (column 5) resulting in a net under-recovery of $51,531,817 (column 6). Exhibit RBD-1, page 3 shows that the variance consists of an increase in jurisdictional fuel costs of $101.0 million (line 38) partially offset by an increase in revenues of $49.6 million (line 29).

Q. Please summarize the variance schedule on page 3 of Exhibit RBD-1.

A. FPL previously projected jurisdictional total fuel costs and net power transactions to be $2.58 billion for 2019 (Exhibit RBD-1, page 3, line 38, column 5). The actual jurisdictional total fuel costs and net power transactions for that period is $2.69 billion (Exhibit RBD-1, page 3, line 38, column 4). Jurisdictional total fuel costs and net power transactions are $101.0 million, or 3.9% higher than previously projected (Exhibit RBD-1, page 3, line 38, column 6) and jurisdictional fuel revenues net of revenue taxes for 2019 are $49.6 million, or 1.7% higher than previously projected (Exhibit RBD-1, page 3, line 29, column 6).

Q. Please explain the variances in jurisdictional total fuel costs and net power transactions.

A. Below are the primary reasons for the $101.0 million variance.

Fuel Cost of System Net Generation: $125.8 million increase (Exhibit RBD-1, page 3, line 1, column 6)

The table below provides the detail of this variance.

FUEL VARIANCE	2019 FINAL TRUE-UP	2019 ACTUAL/ ESTIMATED	DIFFERENCE
Heavy Oil			
Total Dollar	$13,793,931	$12,853,413	940,518
Units (MMBTU)	1,196,123	1,115,626	80,498
$ per Units	11.5322	11.5213	0.01
Variance Due to Consumption			928,316
Variance Due to Cost			12,202
Total Variance			940,518
Light Oil			
Total Dollar	$20,107,057	$11,992,199	8,114,858
Units (MMBTU)	1,182,072	706,510	475,563
$ per Units	17.0100	16.9739	0.04

FUEL VARIANCE	2019 FINAL TRUE-UP	2019 ACTUAL/ ESTIMATED	DIFFERENCE
Variance Due to Consumption			8,089,322
Variance Due to Cost			25,536
Total Variance			8,114,858
Coal			
Total Dollar	$74,236,959	$69,189,030	5,047,929
Units (MMBTU)	28,631,872	27,200,891	1,430,981
$ per Units	2.5928	2.5436	0.05
Variance Due to Consumption			3,710,260
Variance Due to Cost			1,337,670
Total Variance			5,047,929
Gas			
Total Dollar	$2,600,448,500	$2,493,615,287	106,833,213
Units (MMBTU)	665,984,354	637,898,271	28,086,083
$ per Units	3.9047	3.9091	(0.00)
Variance Due to Consumption			109,666,859
Variance Due to Cost			(2,833,646)
Total Variance			106,833,213
Nuclear			
Total Dollar	$159,950,571	$155,046,037	4,904,534
Units (MMBTU)	303,397,508	298,655,844	4,741,664
$ per Units	0.5272	0.5191	0.01
Variance Due to Consumption			2,499,796
Variance Due to Cost			2,404,738
Total Variance			4,904,534
Total			
Variance Due to Consumption			124,894,552
Variance Due to Cost			946,500
Total Variance			125,841,052

Variable Power Plant O&M Avoided due to Economy Purchases: $0.05 million decrease (Exhibit RBD-1, page 3, line 13, column 6)

The variance for variable power plant O&M avoided due to economy purchases is attributable to lower than projected economy power purchases.

Variable Power Plant O&M Attributable to Off-System Sales: $0.1 million increase (Exhibit RBD-1, page 3, line 12, column 6)

The variance for variable power plant O&M attributable to off-system sales is attributable to higher than projected economy power sales.

Energy Cost of Economy Purchases: $1.4 million increase (Exhibit RBD-1, page 3, line 8, column 6)

The variance for the Energy Cost of Economy Purchases is attributable to higher than projected costs for economy power. The average cost of economy power purchases was $7.95/MWh higher than projected, resulting in a cost increase of $4.4 million. This increase was partially offset by lower than projected economy purchases. FPL purchased 76,939 MWh less of economy power, resulting in a volume decrease of $3.0 million. The combination of lower economy power purchases coupled with higher costs for economy power purchases resulted in a net variance of $1.4 million.

Fuel Cost of Power Sold: $2.6 million increase (Exhibit RBD-1, page 3, line 4, column 6)

The variance for the Fuel Cost of Power Sold is primarily attributable to higher than projected economy power sales. FPL sold 191,325 MWh more of economy power, resulting in a volume increase of $3.8 million. The average unit fuel cost on economy power sales was $0.48/MWh lower than projected, resulting in a cost decrease of $1.3 million. The combination of higher economy power sales and lower fuel costs attributable to economy power sales resulted in a net variance for economy power sales of $2.5 million. The remaining variance of $0.1 million was primarily attributable to higher than projected fuel costs on St. Lucie Plant Reliability Exchange sales.

Gains from Off-System Sales: $2.4 million increase (Exhibit RBD-1, page 3, line 5, column 6)

The variance for Gains from Off-System Sales is attributable to higher than projected economy sales and higher than projected margins on economy power sales. FPL sold 191,325 MWh more of economy power, resulting in a volume increase of $1.7 million. Margins on economy power sales averaged $0.26/MWh higher than projected, resulting increased gains of $0.7 million. The combination of higher economy power sales and higher margins on economy power sales resulted in a total variance for Gains from Off-System Sales of $2.4 million.

Fuel Cost of Stratified Sales: $6.4 million increase (Exhibit RBD-1, page 3, line 2, column 6)

The variance for the fuel cost of stratified sales is primarily attributable to higher than projected MWh sales to Seminole.

Fuel Cost of Purchased Power: $0.8 million increase (Exhibit RBD-1, page 3, line 6, column 6)

The variance for the Fuel Cost of Purchased Power is primarily attributable to higher than projected firm purchases and lower than projected costs associated with these firm purchases. In total, FPL purchased 130,894 MWh more than projected, resulting in a volume increase of $2.7 million. The unit cost of these firm purchases was $1.15/MWh lower than projected, resulting in a cost decrease of $1.9 million. The combination of higher firm purchases and lower costs for firm purchases resulted in a net variance of $0.8 million.

<u>Energy Payments to Qualifying Facilities: $0.1 million increase (Exhibit RBD-1, page 3, line 7, column 6)</u>

The variance for Energy Payments to Qualifying Facilities is attributable to higher than projected purchases and lower than projected costs from Qualifying Facilities. In total, FPL purchased 23,134 MWh more than projected, resulting in a volume increase of $0.4 million. The average unit fuel cost for these purchases was $1.02/MWh lower than projected, resulting in a cost decrease of $0.3 million. The combination of higher purchases and lower fuel costs for Qualifying Facilities resulted in a net variance of $0.1 million.

Q. What is the variance in retail (jurisdictional) FCR revenues?

A. As shown on Exhibit RBD-1, page 3, line 29, actual 2019 jurisdictional FCR revenues, net of revenue taxes, are approximately $49.6 million higher than the actual/estimated projection. This is primarily due to jurisdictional sales that are 1,591,574 MWh higher than the actual/estimated projection.

Q. FPL witness Yupp calculates in his testimony that FPL is entitled to retain $9,149,588 as its 60% share of 2019 Incentive Mechanism gains over the $40 million threshold. When is FPL requesting to recover its share of the gains,

and how will this be reflected in the FCR schedules?

A. FPL is requesting recovery of its share of the 2019 Incentive Mechanism gains through the 2021 FCR factors, consistent with how gains have been recovered in prior years. FPL will include the approved jurisdictionalized Incentive Mechanism gains amount in the calculation of the 2021 FCR factors and will reflect recovery of one-twelfth of the approved amount, net of revenue taxes, in each month's Schedule A2 for the period January 2021 through December 2021 as a reduction to jurisdictional fuel revenues applicable to each period.

CAPACITY COST RECOVERY CLAUSE

Q. Please explain the calculation of the 2019 CCR net true-up amount.

A. Exhibit RBD-2, page 1, titled "Final True-Up Summary" shows the calculation of the CCR net true-up for the period January 2019 through December 2019, an over-recovery of $5,141,967, which FPL is requesting to be included in the calculation of the CCR factors for the January 2021 through December 2021 period.

The actual end-of-period over-recovery for the period January 2019 through December 2019 of $14,144,582 shown on line 1 less the actual/estimated end-of-period over-recovery for the same period of $9,002,615 shown on line 2 that was approved by the Commission in Order No. PSC-2019-0484-FOF-EI, results in the net true-up over-recovery for the period January 2019 through December 2019 of $5,141,967 shown on line 3.

Q. Have you provided a schedule showing the calculation of the 2019 CCR actual true-up by month?

A. Yes. Exhibit RBD-2, pages 2 through 4, titled "Calculation of Final True-Up" shows the calculation of the CCR end-of-period true-up for the period January 2019 through December 2019 by month.

Q. Is this true-up calculation consistent with the true-up methodology used for the FCR Clause?

A. Yes, it is. The calculation of the true-up amount follows the procedures established by this Commission set forth on Commission Schedule A2 "Calculation of True-Up and Interest Provision" for the FCR Clause.

Q. Have you provided a schedule showing the variances between actual and actual/estimated capacity costs and applicable revenues for 2019?

A. Yes. Exhibit RBD-2, pages 5 and 6, titled "Calculation of Final True-Up Variances," shows the actual capacity costs and applicable revenues compared to actual/estimated capacity costs and applicable revenues for the period January 2019 through December 2019.

Q. Please explain the variances related to capacity costs.

A. As shown in Exhibit RBD-2, page 5, line 13, column 5, the variance related to total system capacity costs is a decrease of $3.4 million or 1.3%. Below are the primary reasons for the decrease.

<u>Transmission Revenues from Capacity Sales: $2.2 million increase (Exhibit RBD-2, page 5, line 8, column 5)</u>

The variance for transmission revenues from capacity sales is primarily attributable to higher revenues from capacity premiums associated with power capacity sales of $1.2 million. The remaining variance is primarily due to higher than projected transmission revenues of $1.0 million resulting from higher than projected economy power sales.

<u>Incremental Nuclear NRC Compliance Costs (Fukushima): O&M - $1.0 million decrease (Exhibit RBD-2, page 5, line 5, column 5)</u>

The variance for incremental NRC compliance O&M costs is primarily attributable to deferral of Turkey Point Unit 3 and Unit 4 flooding protection modifications from 2019 to 2020.

Q. Have you included an adjustment to the 2019 CCR true-up to reflect the change to the Florida corporate income tax rate issued by the Florida Department of Revenue?

A. Yes. On September 12, 2019, the Florida Department of Revenue issued a Tax Information Publication providing notification of a reduction in the Florida corporate income tax rate, from 5.5% to 4.458%, for taxable years beginning on or after January 1, 2019, but not before January 1, 2022. The notification also states that further reduction in the tax rate is possible for taxable years beginning on or after January 1, 2020 and January 1, 2021. The reduction in the corporate income tax rate impacted the income taxes associated with the return on equity earned in the capital projects recovered through the CCR. In December 2019, FPL adjusted the CCR true-up balances for January 2019 through November 2019 to reflect the tax rate reduction. As a result, the monthly end of period true-up amounts for January 2019 through June 2019 have been adjusted downward from the amounts filed in FPL's 2019 CCR Actual/Estimated True-Up filing dated July 26, 2019.

Q. Please describe the variance in 2019 CCR revenues.

A. As shown on page 6, line 35, column 5, actual 2019 CCR revenues (net of revenue taxes), are $1.9 million higher than projected in the actual/estimated true-up filing. This is primarily due to 1,591,574 MWh higher than projected jurisdictional sales.

Q. Have you provided a schedule showing the actual monthly capacity payments by contract?

A. Yes. Schedule A12 consists of two pages that are included in Exhibit RBD-2 as pages 7 and 8. Page 7 shows the actual capacity payments for FPL's Purchase Power Agreements for the period January 2019 through December 2019. Page 8 provides the Short Term Capacity Payments for the period January 2019 through December 2019.

Q. Have you provided a schedule showing the capital structure components and cost rates relied upon by FPL to calculate the rate of return applied to all capital projects recovered through the FCR and CCR Clauses?

A. Yes. The capital structure components and cost rates used to calculate the rate of return on the capital investments for the period January 2019 through December 2019 are included on pages 19 and 20 of Exhibit RBD-2.

Q. Does this conclude your testimony?

A. Yes, it does.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF RENAE B. DEATON

DOCKET NO. 20200001-EI

JULY 27, 2020

Q. Please state your name, business address, employer and position.

A. My name is Renae B. Deaton. My business address is 700 Universe Boulevard, Juno Beach, Florida 33408. I am employed by Florida Power & Light Company ("FPL" or "the Company") as Director, Clause Recovery and Wholesale Rates, in the Regulatory & State Governmental Affairs Department.

Q. Have you previously testified in this docket?

A. Yes, I have.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present for Commission review and approval the calculation of the actual/estimated true-up amounts for the Fuel Cost Recovery ("FCR") Clause and the Capacity Cost Recovery ("CCR") Clause for the period January 2020 through December 2020. My testimony also provides a revised 2019 FCR final net true-up amount that reflects revisions to the amount filed on March 2, 2020.

Q. Have you prepared or caused to be prepared under your direction, supervision or control any exhibits with your testimony?

A. Yes, various schedules are included in Exhibits RBD-3, RBD-4 and RBD-5.

Exhibit RBD-3 contains the FCR Schedules. These include Schedules E3 through E9 that provide revised estimates for the period July 2020 through December 2020. FCR Schedules A1 through A9 provide actual data for the period January 2020 through June 2020. The actual data was derived from the FCR A-Schedules A1 through A9 that are filed monthly with the Commission and served on all parties, which are incorporated herein by reference. The FCR schedules contained in Exhibit RBD-3 also provide the calculation of the actual/estimated true-up amount and actual/estimated variances for the period January 2020 through December 2020.

Exhibit RBD-4 contains the CCR schedules, which provide the calculation of the actual/estimated true-up amount and actual/estimated variances for the period January 2020 through December 2020.

Exhibit RBD-5 provides the calculation of the revised final net true-up amount for the period January 2019 through December 2019.

Q. What is the source of the actual data that you present by way of testimony or exhibits in this proceeding?

A. Unless otherwise indicated, the actual data are taken from the books and records of FPL. The books and records are kept in the regular course of the Company's business in accordance with generally accepted accounting principles and practices, as well as the provisions of the Uniform System of Accounts as prescribed by this Commission.

Q. Have you revised the 2019 FCR final net true-up amount that was filed in this docket on March 2, 2020?

A. Yes. The 2019 FCR final true-up amount was revised to include $89,873 associated with missing railcar lease and energy imbalance expenses. This revision decreases the actual 2019 FCR end of period true-up over-recovery amount, including interest, from $77,204,120 to $77,114,247 and increases the 2019 FCR final net true-up under-recovery amount, including interest from $51,531,817 to $51,621,690. Exhibit RBD-5 of my testimony provides the revised schedules reflecting the calculation of the revised 2019 FCR final net true-up under-recovery amount of $51,621,690.

Q. Please describe the data that FPL has used as a comparison when calculating the FCR and CCR actual/estimated true-up amounts presented in your testimony.

A. The FCR true-up calculation compares actual/estimated data consisting of actuals for January 2020 through June 2020 and revised estimates for July 2020 through December 2020 to the data reflected in FPL's midcourse correction approved by Order No. PSC-2020-0154-PCO-EI, issued on May 14, 2020. The CCR true-up calculation compares actual/estimated data consisting of actuals for January 2020 through June 2020 and revised estimates for July 2020 through December 2020 to the data reflected in FPL's original projection for the period January 2020 through December 2020 filed on September 3, 2019.

Q. Please explain the calculation of the interest provision that is applicable to the FCR and CCR true-up amounts.

A. The calculation of the interest provision follows the methodology used in calculating the interest provision for all cost recovery clauses, as previously approved by this Commission. The interest provision is the result of multiplying the monthly average true-up amount for the twelve-month period by the monthly average interest rate. The average interest rate for the months reflecting actual data is developed using the AA financial 30-day rates as published on the Federal Reserve website on the first business day of the current month and the subsequent month divided by two. The average interest rate for the projected months is the actual rate published on the first business day in July 2020, which reflects the interest rate from the last business day in June 2020.

FUEL COST RECOVERY CLAUSE

Q. Have you provided a schedule showing the calculation of the FCR 2020 actual/estimated true-up by month?

A. Yes. Exhibit RBD-3, page 1 shows the calculation of the FCR actual/estimated true-up by month for the period January 2020 through December 2020.

Q. Please explain the calculation of the FCR end-of-period net true-up and actual/estimated true-up amounts you are requesting this Commission to approve.

A. Exhibit RBD-3, page 1 shows the calculation of the FCR end-of-period net true-up and actual/estimated true-up amounts. The 2020 end-of-period net true-up amount to be carried forward to the 2021 FCR factors is an under-recovery of $20,669,910 (page 1, line 44, column 16). This $20,669,910 under-recovery includes the revised 2019 final net true-up under-recovery of $51,621,690 (Exhibit RBD-3, page 1, line 42, column 16), included in this filing as Exhibit RBD-5, and the actual/estimated true-up over-recovery, including interest, of $30,951,780 (Exhibit RBD-3, page 1, lines 39 plus 40, column 16) for the period January 2020 through December 2020.

Q. Were these calculations made in accordance with the procedures previously approved in predecessors to this Docket?

A. Yes.

Q. Have you provided a schedule showing the variances between the actual/estimated amounts and the midcourse correction amounts for 2020?

A. Yes. Exhibit RBD-3, page 2 provides a variance calculation that compares the 2020 actual/estimated period data by component to the same components from the midcourse correction filing.

Q. Please summarize the variance schedule on page 2 of Exhibit RBD-3.

A. FPL's midcourse correction filing projected jurisdictional total fuel costs and net power transactions to be $2.246 billion for 2020 (Exhibit RBD-3, page 2, line 39, column 5). The actual/estimated jurisdictional total fuel costs and net power transactions are now projected to be $2.231 billion for that period (Exhibit RBD-3, page 2, line 39, column 4). The estimated variance is due to lower than projected costs combined with higher than projected sales and revenues. Jurisdictional total fuel costs and net power transactions are estimated to be $15.2 million, or 0.7% lower than the midcourse correction estimates (Exhibit RBD-3, page 2, line 39, column 6), and jurisdictional fuel revenues applicable to the period, net of revenue taxes are projected to be $15.6 million, or 0.7% higher than the midcourse correction estimates (Exhibit RBD-3, page 2, line 36, column 6). The net impact due to the decrease in jurisdictional fuel costs and the increase in jurisdictional fuel revenues applicable to the period result in the actual/estimated true-up over-recovery of $30.9 million (Exhibit RBD-3, page 2, line 40, column 6).

Q. Please explain the variances in jurisdictional total fuel costs and net power transactions.

A. Below are the primary reasons for the $15.2 million variance in jurisdictional total fuel costs.

Fuel Cost of System Net Generation: $0.744 million decrease (Exhibit RBD-3, page 2, line 1, column 6)

The table below provides the detail of this variance.

FUEL VARIANCE	MAY 2020 MIDCOURSE CORRECTION	2020 ACTUAL/ESTIMATED	DIFFERENCE
Heavy Oil			
Cost	$10,809,864	$13,866,418	$3,056,554
MMBTU	950,703	1,271,430	320,727
$ per MMBTU	11.37	10.91	(0.46)
Variance due to consumption			$ 3,646,790
Variance due to cost			$ (590,236)
Total Variance			$ 3,056,554
Light Oil			
Cost	$6,810,004	$14,804,568	$7,994,564
MMBTU	435,631	1,053,796	618,165
$ per MMBTU	15.63	14.05	(1.58)
Variance due to consumption			$ 9,663,469
Variance due to cost			$ (1,668,905)
Total Variance			$ 7,994,564

FUEL VARIANCE	MAY 2020 MIDCOURSE CORRECTION	2020 ACTUAL/ESTIMATED	DIFFERENCE
Coal			
Cost	$48,159,717	$50,709,323	$2,549,606
MMBTU	18,706,307	19,137,147	430,840
$ per MMBTU	2.57	2.65	0.08
Variance due to consumption			$ 1,109,205
Variance due to cost			$ 1,440,400
Total Variance			$ 2,549,606
Natural Gas			
Cost	$2,186,682,264	$2,169,620,296	($17,061,968)
MMBTU	620,020,852	640,798,422	20,777,570
$ per MMBTU	3.53	3.39	(0.14)
Variance due to consumption			$ 73,278,090
Variance due to cost			$ (90,340,058)
Total Variance			$ (17,061,968)
Nuclear			
Cost	$144,970,704	$147,687,701	$2,716,996
MMBTU	298,230,369	307,086,334	8,855,965
$ per MMBTU	0.49	0.48	(0.01)
Variance due to consumption			$ 4,304,912
Variance due to cost			$ (1,587,916)
Total Variance			$ 2,716,996
Total System			
Total Dollar	$2,397,432,553	$2,396,688,306	($744,248)
Units (MMBTU)	938,343,862	969,347,129	31,003,267
$ per Unit	2.55	2.47	(0.08)
Variance due to consumption			$ 79,212,158
Variance due to cost			$ (79,956,405)
Total Variance			$ (744,248)

<u>Fuel Cost of Stratified Sales: $10.1 million increase (Exhibit RBD-3, page 2, line 2, column 6)</u>

The variance for the fuel cost of stratified sales is primarily attributable to higher than projected sales under stratified contracts, resulting in a larger credit to fuel costs.

<u>Fuel Cost of Power Sold: $3.3 million increase (Exhibit RBD-3, page 2, line 4, column 6)</u>

The variance of ($3,315,090) for the Fuel Cost of Power Sold is primarily attributable to higher than projected economy power sales. FPL now projects to sell 128,146 MWh more of economy power, resulting in a volume variance of ($2,088,575). The average unit fuel cost on economy power sales is now projected to be $0.34/MWh higher than originally projected, resulting in a cost variance of ($973,104). The combination of higher economy power sales and higher fuel costs attributable to economy power sales results in a total variance for economy power sales of ($3,061,679). The remaining variance of ($253,411) is attributable to higher than projected St. Lucie Plant Reliability Exchange sales and higher than projected fuel costs attributable to St. Lucie Plant Reliability Exchange sales.

<u>Energy Cost of Economy Purchases: $2.1 million decrease (Exhibit RBD-3, page 2, line 8, column 6)</u>

The variance for the Energy Cost of Economy Purchases is primarily attributable to lower than projected economy power purchases. FPL now projects to purchase 81,518 MWh less of economy power resulting in a volume variance of ($2,276,824). The average cost of economy purchases is now projected to be $0.55/MWh higher than originally projected, resulting in a cost variance of $202,936. The combination of lower economy power purchases coupled with higher costs for economy power purchases results in a net variance of ($2,073,888).

<u>Gains from Off-System Sales: $0.691 million increase (Exhibit RBD-3, page 2, line 5, column 6)</u>

The variance for Gains from Off-System Sales is primarily attributable to higher than projected economy power sales. FPL now projects to sell 128,146 MWh more of economy power, resulting in a volume variance of ($1,146,732). This variance is partially offset by lower than projected margins on economy power sales. FPL now projects that margins on economy power sales will be $0.16/MWh lower than originally projected, resulting in a cost variance of $455,579. The combination of higher economy power sales and lower margins on economy power sales results in a net variance for Gains from Off-System Sales of ($691,153).

<u>Energy Payments to Qualifying Facilities: $0.250 million increase (Exhibit RBD-3, page 2, line 7, column 6)</u>

The variance of $250,474 for Energy Payments to Qualifying Facilities is primarily attributable to higher than projected purchases from As-Available Co-Generation facilities. FPL now projects to purchase 46,027 MWh more from As-Available Co-Generation facilities, resulting in a volume variance of $673,277. This variance is partially off-set by lower than projected fuel costs from As-Available Co-Generation facilities. Fuel costs are now projected to be $1.26/MWh lower, resulting in a cost variance of ($399,594). The combination of higher purchases and lower fuel costs from As-Available Co-Generation facilities results in a net variance of $273,683. This variance is slightly offset by a variance of ($23,208) that is primarily related to lower than projected fuel costs from Firm Co-Generation facilities.

<u>Variable Power Plant O&M Attributable to Off-System Sales: $0.083 million increase (Exhibit RBD-3, page 2, line 12, column 6)</u>

The variance of $83,295 is attributable to higher than originally projected economy power sales.

<u>Variable Power Plant O&M Avoided due to Economy Purchases: $0.053 million decrease (Exhibit RBD-3, page 2, line 13, column 6)</u>

The variance of $52,987 is attributable to lower than originally projected economy power purchases.

CAPACITY COST RECOVERY CLAUSE

Q. Have you provided a schedule showing the calculation of the CCR 2020 actual/estimated true-up by month?

A. Yes. Exhibit RBD-4, page 1 provides the calculation of the CCR actual/estimated true-up by month for the period January 2020 through December 2020.

Q. Please explain the calculation of the CCR 2020 actual/estimated true-up and the end-of-period net true-up amounts you are requesting this Commission to approve.

A. Exhibit RBD-4, pages 4 and 5 shows the actual/estimated capacity costs and applicable revenues (January 2020 through June 2020 reflects actual data, while the data for July 2020 through December 2020 is based on updated estimates) compared to the original projection filing for the January 2020 through December 2020 period. The CCR revenues (net of revenue taxes) are projected to be $4,478,014 (Exhibit RBD-4, page 5, line 27, column 5) higher than FPL's original projection filing. Jurisdictional total capacity costs are estimated to be $2,790,978 lower than the original projection filing (Exhibit RBD-4, page 5, line 24, column 5). The $2,790,978 over-recovery due to lower jurisdictional capacity costs combined with the $4,478,014 increase in revenues, results in the 2020 actual/estimated true-up over-recovery amount of $7,388,454, including interest (Exhibit RBD-4, page 5, lines 32 plus 33, column 5).

As shown on Exhibit RBD-4, page 3, the 2020 end-of period net true up amount to be carried forward to the 2021 CCR factors is an over-recovery of $12,530,421 (line 14, column 15). This $12,530,421 net over-recovery is comprised of the 2019 final true-up over-recovery of $5,141,967 (line 11, column 15), and the actual/estimated true-up over-recovery, including interest, of $7,388,454 for the period January 2020 through December 2020 (lines 8 plus 9, column 15).

Q. Is this true-up calculation made in accordance with the procedures previously approved in predecessors to this docket?

A. Yes.

Q. Please explain the variances related to capacity costs.

A. As shown in Exhibit RBD-4, page 5, line 1, column 5, total system capacity costs are estimated to be $2.9 million or 1.1% less than projected in FPL's original projection filing. The variance related to the jurisdictional portion of these costs is also a 1.1% decrease from the original projection (page 5, line 24, column 6). Below are the primary reasons for the estimated $2.9 million decrease in total system capacity costs.

Transmission Revenues from Capacity Sales: $1.9 million increase (Exhibit RBD-4, page 4, line 11, column 5)

Approximately ($1.02 million) of the total variance is attributable to higher revenues from capacity premiums associated with power capacity sales. Higher than originally projected transmission revenues from economy sales resulted in a variance of approximately ($879,000).

Incremental Nuclear NRC Compliance Costs – Capital: $1.1 million decrease (Exhibit RBD-4, page 4, line 9, column 5)

The variance for incremental nuclear NRC compliance capital costs is primarily attributable to retirements during the Spring 2020 outage at Turkey Point Unit 3 that were not included in the original projections.

Incremental Plant Security Costs – Capital: $0.9 million decrease (Exhibit RBD-4, page 4, line 7, column 5)

The variance for incremental plant security capital costs is primarily attributable to lower than projected costs associated with the implementation of controls at FPL's 16 solar sites required by the NERC CIP Low Impact regulations (CIP-003), which became effective on January 1, 2020.

<u>Transmission of Electricity by Others: $0.1 million decrease (Exhibit RBD-4, page 4, line 10, column 5)</u>

The approximately ($105,000) variance is due to lower than projected costs for the purchase of third-party transmission utilized to facilitate wholesale power sales.

<u>Incremental Plant Security Costs – O&M: $1.1 million increase (Exhibit RBD-4, page 4, line 6, column 5)</u>

The variance for incremental plant security O&M costs is primarily attributable to costs not included in original projections associated with new NERC CIP requirements and new process improvements. The variance was partially offset by the implementation of cost savings initiatives at the St. Lucie and Turkey Point nuclear plants resulting in lower security force costs.

<u>Incremental Nuclear NRC Compliance Costs - O&M: $0.6 million increase (Exhibit RBD-4, page 4, line 8, column 5)</u>

The variance for incremental nuclear NRC compliance O&M costs is primarily attributable to deferral of Turkey Point Unit 3 and Unit 4 flooding protection modifications from 2019 to 2020.

Q. Does this conclude your testimony?

A. Yes, it does.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF RENAE B. DEATON

DOCKET NO. 20200001-EI

SEPTEMBER 3, 2020

Q. Please state your name, business address, employer and position.

A. My name is Renae B. Deaton. My business address is 700 Universe Boulevard, Juno Beach, Florida 33408. I am employed by Florida Power & Light Company ("FPL" or "the Company") as the Director, Clause Recovery and Wholesale Rates in the Regulatory & State Governmental Affairs Department.

Q. Have you previously testified in this docket?

A. Yes, I have.

Q. What is the purpose of your testimony?

A. My testimony addresses the following subjects:

- The Fuel Cost Recovery ("FCR") Clause factors for the period January 2021 through December 2021;
- The calculation of the jurisdictional amount of FPL's portion of the 2019 incentive mechanism gains to be recovered through the 2021 FCR factors;
- The Capacity Cost Recovery ("CCR") Clause factors for the period January 2021 through December 2021 and the CCR factors for the same period, including a refund for the 2018 SoBRA true-up, and an adjustment to recover the non-fuel revenue requirements associated with the Indiantown

Cogeneration L.P. facility ("Indiantown"), as approved in Order No. PSC-16-0506-FOF-EI, issued in Docket No. 160154-EI on November 2, 2016;

- The non-fuel revenue requirement calculation for Indiantown for the period January 2021 through December 2021; and
- FPL's proposed cogeneration as-available energy ("COG-1") tariff sheets, which reflect updated variable operation and maintenance expense and loss factors.

Q. Have you prepared or caused to be prepared under your direction, supervision, or control any exhibits in this proceeding?

A. Yes, I have. They are as follows:

Exhibit RBD-6 (Appendix II)

- Schedules E1, E1-A, E1-C, E1-D, E1-E, E2, Calculation of Jurisdictional Incentive Mechanism Gains – FPL Portion, RS-1 Inverted Rate Calculation, H1 and E10 provide the calculation of FCR factors for January 2021 through December 2021;
- Pages 9 through 12, which provide the 2021 Projected Energy Losses by Rate Class;
- Pages 101 and 102, which provide updated COG-1 tariff sheets;

Exhibit RBD-7 (Appendix III)

- Pages 1 through 4 provide the calculation of the 2021 CCR factors including the refund for the 2018 SoBRA true-up, and excluding the Indiantown non-fuel revenue requirements for January 2021 through December 2021;

- Pages 5 through 10 provide the calculation of depreciation and return on incremental power plant security and incremental Nuclear Regulatory Commission ("NRC") compliance capital investments;
- Page 11 provides the calculation of amortization and return on the regulatory asset related to the Cedar Bay Transaction;
- Page 12 provides the calculation of amortization and return on the regulatory liability related to the Cedar Bay Transaction;
- Page 13 provides the calculation of amortization and return on the regulatory asset related to Indiantown;
- Page 14 provides the calculation of amortization and return on the regulatory asset and liability related to St. Johns River Power Park, and the refund to customers associated with the deferred interest liability and dismantlement;
- Page 15 provides the capital structure, components and cost rates relied upon to calculate the rate of return applied to capital investments and working capital amounts included for recovery through the CCR clause for the period January 2021 through December 2021;
- Pages 18 and 19 provide the calculation of the portion of the CCR factors that recovers the non-fuel revenue requirements associated with Indiantown for the period January 2021 through December 2021;
- Page 20 combines the results from pages 1 through 4 and pages 18 and 19 to provide the total 2021 CCR factors including the non-fuel revenue requirements associated with Indiantown for the period January 2021

through December 2021;

- Pages 21 and 22 provide the calculation of the Indiantown revenue requirements for January 2021 through December 2021;
- Pages 23 through 38 provide the calculations of stratified separation factors.

FUEL COST RECOVERY CLAUSE

Q. What adjustments are included in the calculation of the 2021 FCR factors shown on Schedule E1 included in Appendix II?

A. The 2021 FCR factors include adjustments for the total net true-up, the Generating Performance Incentive Factor ("GPIF"), the jurisdictional amount associated with FPL's share of the 2019 incentive mechanism gains and the cost associated with the 2021 Subscription Credit for the FPL SolarTogether Program.

The total net true-up to be included in the 2021 FCR factors is an under-recovery of $20,669,910, as shown on line 28 of Schedule E1. This amount, divided by the projected retail sales of 111,812,880 MWh for January 2021 through December 2021, results in an increase of 0.0185 cents per kWh before applicable revenue taxes.

The GPIF testimony of witness Charles R. Rote, filed on March 16, 2020, proposes a reward of $8,125,681 for the period ending December 2019, as shown on line 32 of Schedule E1. This $8,125,681 reward, divided by the projected retail sales of 111,812,880 MWh for January 2021 through December 2021, results in an increase of 0.0073 cents per kWh.

FPL is including $8,703,535 for the jurisdictional amount associated with its share of 2019 incentive mechanism gains in the calculation of its 2021 FCR factors, as shown on line 33 of Schedule E1. As presented and explained in the direct testimony and exhibits of FPL witness Gerard J. Yupp filed on March 2, 2020 in this docket, FPL's activities under the incentive mechanism in 2019 delivered $55,249,313 in total gains. Of these total gains, FPL is allowed to retain $9,149,588 (system amount) per Order No. PSC-13-0023-S-EI dated January 14, 2013 and Order No. PSC-16-0560-AS-EI dated December 15, 2016. FPL will reflect recovery of one-twelfth of the approved jurisdictional amount of $8,703,535, net of revenue taxes, in each month's Schedule A2 for the period January 2021 through December 2021 as a reduction to jurisdictional fuel revenues applicable to each period. The calculation of the jurisdictional amount of the 2019 incentive mechanism gains adjusted for revenue taxes is shown on page 4 of Appendix II. This $8,703,535, divided by the projected retail sales of 111,812,880 MWh for January 2021 through December 2021, results in an increase of 0.0078 cents per kWh.

Per the Settlement Agreement approved in Order No. PSC-2020-0084-S-EI, issued in Docket No. 20190061 on March 20, 2020, FPL has included $98,939,400 (adjusted for revenue taxes) associated with the 2021 Subscription Credit for the

FPL SolarTogether Program, as shown on line 34 of Schedule E1. The subscription credit reflects the estimated economic value of the program's solar power plants on FPL's system, which consists of reduced fuel, purchased power, and carbon emission costs. As approved in Order No. PSC-2020-0084-S-EI, the subscription credit is to be recovered through FPL's fuel cost recovery clause, partially offsetting system savings resulting from the addition of the program's solar power plants. This $98,939,400, divided by the projected retail sales of 111,812,880 MWh for January 2021 through December 2021, results in an increase of 0.0885 cents per kWh.

Schedule E2 provides the monthly fuel factors as well as the levelized FCR factor for 2021. Schedule E-1E provides the calculation of the 2021 FCR factors by rate group for each period.

Q. Please explain the fuel cost of stratified sales amount reflected on line 2 of Schedule E1.

A. FPL has included a credit of $14,823,385 associated with stratified wholesale power sales contracts in effect in 2021. The fuel costs for wholesale power contracts are calculated based on a guaranteed heat rate and a fuel price index. The fuel costs of wholesale sales are normally included in the total cost of fuel and net power transactions used to calculate the average system cost per kWh for fuel adjustment purposes. However, since the fuel cost of the stratified sales are not recovered on an average system cost basis, an adjustment has been made to remove these costs and the related kWh sales from the fuel adjustment calculation. This adjustment was performed in the same manner that off-system sales are removed from the calculation, consistent with Order No. PSC-97-0262-FOF-EI.

CAPACITY COST RECOVERY CLAUSE

Q. Have you prepared a summary of the requested capacity costs for the projected period of January 2021 through December 2021?

A. Yes. Pages 1 and 2 of Appendix III provides this summary. Total recoverable capacity costs for the period January 2021 through December 2021 are $213,002,247 (page 2, line 32). This includes $237,781,299 for 2021 projected jurisdictional capacity costs, the net true-up over-recovery for 2019 and 2020 of $12,530,421 (line 27 plus line 28), a $12,401,882 refund associated with the 2018 SoBRA true-up (line 29), and revenue taxes. This $213,002,247 excludes the 2021 Indiantown non-fuel revenue requirements.

Q. **Please describe the adjustment associated with the true-up of the 2018 SoBRA.**

A. Pursuant to the 2016 Base Rate Settlement Agreement, a true-up of the SoBRA is required if actual capital costs are lower than projected. As such, FPL has included a credit of $12.4 million, including interest, (Appendix III, page 2, line 29) for the true-up of 2018 SoBRA costs as a reduction in the calculation of its 2021 CCR factors. The calculation of this credit is discussed in the declaration of Edward J. Anderson.

Q. What are the projected Indiantown jurisdictional non-fuel revenue requirements for the January 2021 through December 2021 period?

A. The jurisdictional non-fuel revenue requirements for January 2021 through December 2021 are $1,356,055. The calculation of this amount is shown on Exhibit RBD-7, Appendix III. FPL has made an adjustment for the Indiantown non-fuel revenue requirements consistent with the method previously used when the West County Energy Center Unit 3 non-fuel revenue requirements were recovered through the CCR as approved in Order No. PSC-13-0023-S-EI, issued in Docket No. 120015-EI on January 14, 2013.

Q. Please describe the Weighted Average Cost of Capital ("WACC") that is used in the calculation of the return on the 2021 capital investments included for recovery.

A. FPL calculated and applied a projected 2021 WACC in accordance with the methodology established in Commission Order No. PSC-2020-0165-PAA-EU, Docket No. 20200118-EU, issued on May 20, 2020 ("2020 WACC Order"). Pursuant to the 2020 WACC Order, the WACC was calculated using the currently approved mid-point return on equity and the proration formula prescribed by Treasury Regulation §1.167(l)-1(h)(6)(i) applied to the plant only depreciation-related Accumulated Deferred Federal Income Tax balances included in the capital structure. This projected WACC is used to calculate the rate of return applied to the 2021 CCR capital investments. The projected capital structure, components and cost rates used to calculate the rate of return are provided on page 15 of Exhibit RBD-7 in Appendix III.

Q. Have you provided a calculation of 2021 CCR factors by rate class including an adjustment to recover the non-fuel revenue requirements associated with

Indiantown for the period January 2021 through December 2021?

A. Yes. As approved in Order No. PSC-16-0506-FOF-EI, FPL has included on pages 18 and 19 of Exhibit RBD-7, Appendix III, the 2021 non-fuel revenue requirements associated with Indiantown of $1,356,055. Page 20 of Exhibit RBD-7, Appendix III, shows the calculation of the 2021 CCR factors including the non-fuel revenue requirements associated with Indiantown for the period January 2021 through December 2021.

Q. Has FPL accounted for stratified wholesale power sales contracts in the jurisdictional separation of projected 2021 capacity costs?

A. Yes. FPL has separated the production-related capacity costs based on stratified separation factors that better reflect the types of generation required to serve load under stratified wholesale power sales contracts. The use of stratified separation factors thus results in a more accurate separation of capacity costs between the retail and wholesale jurisdictions. The stratified separation factors are provided in Appendix III, pages 23-38.

Q. Have you prepared a calculation of the allocation factors for demand and energy?

A. Yes. Page 3 of Appendix III provides this calculation. The demand allocation factors are calculated by determining the percentage each rate class contributes to the monthly system peaks. The energy allocators are calculated by determining the percentage each rate class contributes to total kWh sales, as adjusted for losses.

Q. What are the effective dates that FPL is requesting for the new FCR and CCR factors for 2021?

A. FPL is requesting that the FCR factors and the CCR factors for the period January 2021 through December 2021 become effective starting with meter readings made on or after January 1, 2021. These factors should remain in effect until modified by this Commission.

Proposed 2021 Residential Bill

Q. What is FPL's proposed residential 1,000 kWh bill for the period January 2021 through December 2021?

A. FPL's proposed residential 1,000 kWh bill for January 2021 through December 2021 is $99.05. This proposed bill includes a base rate charge of $69.90, which reflects a reduction of $0.04 associated with the true-up of FPL's 2018 SoBRA project, an FCR charge of $21.23, a CCR charge of $2.04, an environmental cost recovery charge of $1.49, a conservation cost recovery charge of $1.49, a storm protection plan cost recovery charge of $0.42 and gross receipts tax of $2.48. FPL's proposed residential 1,000 kWh bill for 2021 is provided on Schedule E-10, which is page 99 of Appendix II.

Q. Does this conclude your testimony?

A. Yes, it does.

(Whereupon, prefiled direct testimony of Gerald J. Yupp was inserted.)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF GERARD J. YUPP

DOCKET NO. 20200001-EI

MARCH 2, 2020

Q. Please state your name and address.

A. My name is Gerard J. Yupp. My business address is 700 Universe Boulevard, Juno Beach, Florida, 33408.

Q. By whom are you employed and what is your position?

A. I am employed by Florida Power and Light Company ("FPL") as Senior Director of Wholesale Operations in the Energy Marketing and Trading Division.

Q. Please summarize your educational background and professional experience.

A. I graduated from Drexel University with a Bachelor of Science Degree in Electrical Engineering in 1989. I joined the Protection and Control Department of FPL in 1989 as a Field Engineer where I was responsible for the installation, maintenance, and troubleshooting of protective relay equipment for generation, transmission and distribution facilities. While employed by FPL, I earned a Masters of Business Administration degree from Florida Atlantic University in 1994. In 1996, I joined the Energy Marketing and Trading Division ("EMT") of FPL as a real-time power trader. I progressed through several power trading positions and assumed the lead role for power trading in 2002. In 2004, I became the Director of Wholesale Operations and natural gas and fuel oil procurement and operations were added to my responsibilities. I have been in my current role since 2008. On the operations side, I am responsible for the procurement and management of all natural gas and fuel oil for FPL, as well as all short-term power trading activity. Finally, I am responsible for the oversight of FPL's optimization activities associated with the Incentive Mechanism.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present the 2019 results of FPL's activities under the Incentive Mechanism that was originally approved by Order No. PSC-13-0023-S-EI, dated January 14, 2013, in Docket No. 120015-EI and approved for continuation, with certain modifications, by Order No. PSC-16-0560-AS-EI, dated December 15, 2016, in Docket No. 160021-EI.

Q. Have you prepared or caused to be prepared under your supervision, direction and control any exhibits in this proceeding?

A. Yes, I am sponsoring the following exhibit:

- GJY-1, consisting of 4 pages:
    - Page 1 – Total Gains Schedule
    - Page 2 – Wholesale Power Detail
    - Page 3 – Asset Optimization Detail
    - Page 4 – Incremental Optimization Costs

Q. Please provide an overview of the Incentive Mechanism.

A. The Incentive Mechanism is an expanded optimization program that is designed to create additional value for FPL's customers while also providing an incentive to FPL if certain customer-value thresholds are achieved. The Incentive Mechanism includes gains from wholesale power sales and savings from wholesale power purchases, as well as gains from other forms of asset optimization. These other forms of asset optimization include, but are not limited to, natural gas storage optimization, natural gas sales, capacity releases of natural gas transportation, capacity releases of electric transmission and potentially capturing additional value from a third party in the form of an Asset Management Agreement (AMA).

Q. Please describe the modifications that were made to the Incentive Mechanism in FPL's 2016 rate case and approved by Order No. PSC-16-0560-AS-EI.

A. There were two specific modifications made to the Incentive Mechanism in FPL's 2016 rate case. First, the sharing threshold was reduced from $46 million to $40 million. The sharing intervals and percentages remained unchanged from the original Incentive Mechanism. Under the modified Incentive Mechanism, customers continue to receive 100% of the gains up to the new sharing threshold of $40 million. Incremental gains above $40 million continue to be shared between FPL and customers as follows: customers receive 40% and FPL receives 60% of the incremental gains between $40 million and $100 million; and customers receive 50% and FPL receives 50% of all incremental gains above $100 million.

The second modification that was made to the Incentive Mechanism involved variable power plant O&M costs. Under the original Incentive Mechanism, FPL was allowed to recover variable power plant O&M costs incurred to make wholesale sales above 514,000 MWh (the level of wholesale sales that were assumed in forecasting FPL's 2013 test year power plant O&M costs in the MFRs filed in FPL's 2012 rate case). Under the modified Incentive Mechansim, FPL nets economy sales and purchases and recovers the net amount of variable power plant O&M incurred during the year. For example, if economy purchases are greater than economy sales, customers receive a credit for the net variable power plant O&M that has been saved during the year. The per-MWh variable power plant O&M rate that FPL uses to calculate these costs, as described in FPL's 2017 Test Year MFR's filed with the 2016 Rate Petition is $0.65/MWh.

FPL continues to be allowed to recover reasonable and prudent incremental O&M costs incurred in implementing the expanded optimization program under the Incentive Mechanism, including incremental personnel, software and associated hardware costs.

Q. Please summarize the activities and results of the Incentive Mechanism for 2019?

A. FPL's activities under the Incentive Mechanism in 2019 delivered $55,249,313 in total gains. During 2019, FPL's activities under the Incentive Mechanism included wholesale power purchases and sales, natural gas sales in the market and production areas, gas storage utilization, and the capacity release of firm natural gas transportation. Additionally, FPL entered into several Asset Management Agreements related to a small portion of upstream gas transportation during 2019. The total gains of $55,249,313 exceeded the sharing threshold of $40 million. Therefore, the incremental gains above $40 million will be shared between customers and FPL, 40% and 60%, respectively. Exhibit GJY-1, Page 1, shows monthly gain totals, threshold levels and the final gains allocation for 2019.

Q. Please provide the details of FPL's wholesale power activities under the Incentive Mechanism for 2019.

A. The details of FPL's 2019 wholesale power sales and purchases are shown separately on Page 2 of Exhibit GJY-1. FPL had gains of $23,922,292 on wholesale sales and savings of $14,914,467 on wholesale purchases for the year.

Q. Please provide the details of FPL's asset optimization activities under the Incentive Mechanism for 2019.

A. The details of FPL's 2019 asset optimization activities are shown on Page 3 of Exhibit GJY-1. FPL had a total of $16,412,555 of gains that were the result of seven different forms of asset optimization.

Q. Did FPL engage in any new forms of asset optimization during 2019?

A. No. FPL did not engage in any new forms of asset optimization activities during 2019.

Q. Did FPL incur incremental O&M expenses related to the operation of the Incentive Mechanism in 2019?

A. Yes. FPL incurred personnel expenses of $474,309 related to the costs associated with an additional two and one-half personnel required to support FPL's expanded activities under the Incentive Mechanism. FPL also incurred $58,755 in expenses related to licensing fees of OATI WebTrader software. In total, FPL incurred incremental O&M expenses related to the operation of the Incentive Mechanism of $533,064 in 2019.

On the variable power plant O&M side, FPL's actual net economy power sales and purchases totaled 2,147,694 MWh (2,698,881 MWh of economy sales and 551,187 MWh of economy purchases), resulting in net variable power plant O&M costs of $1,396,001 for 2019.

Q. Overall, were FPL's activities under the Incentive Mechanism successful in 2019?

A. Yes. FPL's activities under the Incentive Mechanism were highly successful in 2019. On the wholesale power side, suitable market conditions in the winter period helped drive strong wholesale power sales and high customer demand during the late spring, early summer, and late summer periods provided the opportunity to purchase lower cost power from the market to avoid running more expensive generation. Overall, FPL was able to consistently capitalize on power market opportunities throughout the year to deliver slightly more than $38.8 million in customer benefits. Market opportunities for asset optimization activities related to natural gas were fairly consistent throughout the year and resulted in significant customer benefits of more than $16.4 million. In total, these activities delivered $55,249,313 of gains, which contrast very favorably to the total optimization expenses (personnel and variable power plant O&M) of $1,929,065.

Q. Does this conclude your testimony?

A. Yes it does.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF GERARD J. YUPP

DOCKET NO. 20200001-EI

SEPTEMBER 3, 2020

Q. Please state your name and address.

A. My name is Gerard J. Yupp. My business address is 700 Universe Boulevard, Juno Beach, Florida, 33408.

Q. By whom are you employed and what is your position?

A. I am employed by Florida Power and Light Company ("FPL") as Senior Director of Wholesale Operations in the Energy Marketing and Trading Division.

Q. Have you previously testified in this docket?

A. Yes.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present and explain FPL's projections for (1) the dispatch costs of heavy fuel oil, light fuel oil, coal and natural gas; (2) the availability of natural gas to FPL; (3) generating unit heat rates and availabilities; and (4) the quantities and costs of wholesale (off-system) power sales and purchased power transactions. Additionally, my testimony addresses the Incentive Mechanism results for 2019 and the Incremental Optimization Costs included in FPL's 2021 Projection Filing pursuant to the Incentive Mechanism that was approved in Order No. PSC-16-0560-AS-EI dated December 15, 2016

("2016 Base Rate Settlement Agreement").

Q. Have you prepared or caused to be prepared under your supervision, direction and control any exhibits in this proceeding?

A. Yes, I am sponsoring the following exhibits:

- GJY-2: Appendix I

and I am co-sponsoring:

- Schedules E2 through E9 of Appendix II included in Renae Deaton's Exhibit RBD-6 and Appendix III included in Renae Deaton's Exhibit RBD-7.

FUEL PRICE FORECAST

Q. What forecast methodologies has FPL used for the 2021 recovery period?

A. For natural gas commodity prices, the forecast methodology relies upon the NYMEX Natural Gas Futures contract prices (forward curve). For light and heavy fuel oil prices, FPL utilizes Over-The-Counter ("OTC") forward market prices. Projections for the price of coal are based on actual coal purchases and price forecasts developed by J.D. Energy. Forecasts for the availability of natural gas are developed internally at FPL and are based on contractual commitments and market experience. The forward curves for both natural gas and fuel oil represent expected future prices at a given point in time. The basic assumption made with respect to using the forward curves is that all available data that could impact the price of natural gas and fuel oil in the short-term is incorporated into the curves at all times. FPL utilized forward curve prices from the close of business on July 1, 2020 for calculating its 2021 Fuel Cost Recovery ("FCR") Clause factors.

Q. Has FPL used these same forecasting methodologies previously?

A. Yes. FPL began using the NYMEX Natural Gas Futures contract prices (forward curve) and OTC forward market prices in 2004 for its 2005 projections and has used this methodology consistently since that time.

Q. What are the factors that can affect FPL's natural gas prices during the January through December 2021 period?

A. In general, the key physical factors are (1) North American natural gas demand and domestic production; (2) the level of working gas in underground storage throughout the period; (3) weather (particularly in the winter period); (4) the potential for imports and/or exports of natural gas; and (5) the terms of FPL's natural gas supply and transportation contracts.

In its August 2020 Short-Term Energy Outlook, the Energy Information Administration ("EIA") forecasts Henry Hub natural gas spot prices will average approximately $2.03 per MMBtu in 2020. The EIA expects that natural gas prices will generally rise through the end of 2021, with the sharpest increases occurring during the fall and winter of 2020-2021. The EIA forecasts that Henry Hub spot prices will average $3.14 per MMBtu in 2021. U.S. dry natural gas production is estimated to decline from a forecasted average of 88.7 BCF/day in 2020 to 84 BCF/day in 2021.

Natural gas consumption is forecast to decrease by approximately 3% by year-end 2020 (compared to year-end 2019). For 2020, the largest decrease in natural gas consumption occurs in the industrial sector as a result of reduced manufacturing activity. The overall decline also reflects lower heating demand in early 2020, contributing to lower overall residential and commercial demand. While consumption in 2021 among the residential, commercial, and industrial sectors is expected to increase from 2020 levels, demand in the electric power sector is projected to decrease in response to higher natural gas prices. Overall, natural gas consumption in 2021 is projected to decrease compared to 2020 consumption levels. Natural gas storage levels ended July 2020 at roughly 3.3 trillion cubic feet, 15% higher than than the five-year average. Natural gas storage levels are expected to reach approximately 4.0 trillion cubic feet at the end of October 2020.

Q. Please describe FPL's natural gas transportation portfolio for the January through December 2021 period.

A. FPL utilizes the Florida Gas Transmission Company, LLC ("FGT"), Gulfstream Natural Gas System, LLC ("Gulfstream"), Sabal Trail Transmission, LLC ("Sabal Trail"), and Florida Southeast Connection, LLC ("FSC") pipelines to deliver natural gas to its generation facilities. FPL's total firm transportation capacity ranges from 1,150,000 to 1,274,000 MMBtu/day on FGT, 695,000 MMBtu/day on Gulfstream and 600,000 MMBtu/day on Sabal Trail/FSC. Additionally, FPL projects that during the January through December 2021 period, varying levels of non-firm natural gas transportation capacity will be available, depending on the month.

FPL also has firm transportation capacity on several upstream pipelines that provide FPL access to on-shore gas supply. FPL has 80,000 MMBtu/day of firm transport on the Southeast Supply Header ("SESH") pipeline, 196,500 MMBtu/day (January through October) and 121,500 MMBtu/day (November through December) of firm transport on the Transcontinental Gas Pipe Line Company, LLC ("Transco") Zone 4A lateral, and 319,000 MMBtu/day (January through March), 464,000 MMBtu/day (April through October), and 299,000 MMBtu/day (November through December) of firm transport on the Gulf South Pipeline Company, LP ("Gulf South") pipeline. The firm transportation on the SESH, Transco, and Gulf South pipelines does not increase transportation capacity into the state; however, FPL's firm transportation rights on these pipelines provide access for up to 740,500 MMBtu/day during the summer season of on-shore natural gas supply, which helps diversify FPL's natural gas portfolio and enhance the reliability of fuel supply.

Q. Please describe FPL's natural gas storage position.

A. FPL currently holds 4.0 billion cubic feet ("BCF") of firm natural gas storage capacity in Bay Gas Storage, located in southwest Alabama and 1.0 BCF of firm natural gas storage capacity in Southern Pines Energy Center, located in southeast Mississippi. While the acquisition of upstream transportation capacity (i.e., Gulf South) has helped mitigate a large portion of risk associated with off-shore natural gas supply, natural gas storage capacity remains an important part of FPL's gas portfolio. As FPL's reliance on natural gas has increased, the importance of natural gas storage in helping balance consumption "swings" due to weather and unit availability has also increased. Storage capacity improves reliability by providing a relatively inexpensive insurance policy against supply and infrastructure problems while also increasing FPL's ability to manage supply and demand on a daily basis.

Q. What are FPL's projections for the dispatch cost and availability of natural gas for the January through December 2021 period?

A. FPL's projections of the system average dispatch cost and availability of natural gas, by transport type, by pipeline and by month, are provided on page 3 of Appendix I.

Q. What are the key factors that could affect FPL's price for heavy fuel oil during the January through December 2021 period?

A. The key factors that could affect FPL's price for heavy oil are (1) worldwide demand for crude oil and petroleum products (including domestic heavy fuel oil); (2) non-OPEC crude oil supply; (3) the extent to which OPEC adheres to its quotas and reacts to fluctuating demand for OPEC crude oil; (4) the political and civil tensions in the major producing areas of the world like the Middle East and West Africa; (5) the availability of refining capacity; (6) the price relationship between heavy fuel oil and crude oil; (7) the supply and demand for heavy oil in the domestic market; (8) the terms of FPL's supply and fuel transportation contracts; and (9) domestic and global inventory.

In its August 2020 Short-Term Energy Outlook report, the EIA forecasts West Texas Intermediate crude oil prices will average approximately $38.50 per barrel in 2020 and $45.53 per barrel in 2021. The EIA anticipates global crude oil and other liquid fuels production to decrease by 6.4 million barrels per day in 2020 and increase by 5.2 million barrels per day in 2021, with consumption decreasing by approximately 8.1 million barrels per day in 2020 and increasing by 7.0 million barrels per day in 2021. U.S. crude oil production is projected to decrease by roughly 1.0 million barrels per day in 2020 and decrease by 0.12 million barrels per day in 2021. As always, an increase in geopolitical concerns could create upward pressure on oil prices.

Q. Please provide FPL's projection for the dispatch cost of heavy fuel oil for the January through December 2021 period.

A. FPL's projection for the system average dispatch cost of heavy fuel oil, by month, is provided on page 3 of Appendix I.

Q. What are the key factors that could affect the price of light fuel oil?

A. The key factors are similar to those described for heavy fuel oil.

Q. Please provide FPL's projection for the dispatch cost of light fuel oil for the January through December 2021 period.

A. FPL's projection for the system average dispatch cost of light oil, by month, is provided on page 3 of Appendix I.

Q. What is the basis for FPL's projections of the dispatch cost of coal for Plant Scherer?

A. FPL's projected dispatch costs are based on FPL's price projection for spot coal delivered to the plant.

Q. Please provide FPL's projection for the dispatch cost of coal at Plant Scherer for the January through December 2021 period.

A. FPL's projection for the system average dispatch cost of coal for this period, by month, is shown on page 3 of Appendix I.

Q. Do the fuel costs reflected on Schedule E3 for heavy oil, light oil and coal differ from the dispatch costs shown on page 3 of Appendix I?

A. Yes. FPL maintains inventories of those fuels and runs its plants out of that inventory. The dispatch costs reflect what FPL would pay to replace fuel that is removed from inventory to run the plants. On the other hand, the "charge out" costs for heavy oil, light oil and coal that are reflected on Schedule E3 are based on FPL's weighted average inventory cost, by month, for each fuel type.

PLANT HEAT RATES, OUTAGE FACTORS, PLANNED OUTAGES, AND CHANGES IN GENERATING CAPACITY

Q. Please describe how FPL developed the projected Average Net Heat Rates shown on Schedule E4 of Appendix II.

A. The projected Average Net Heat Rates were calculated by the GenTrader model. The current heat rate equations and efficiency factors for FPL's generating units, which present heat rate as a function of unit power level, were used as inputs to GenTrader for this calculation. The heat rate equations and efficiency factors are updated as appropriate based on historical unit performance and projected changes due to plant upgrades, fuel grade changes, and/or from the results of performance tests.

Q. Are you providing the outage factors projected for the period January through December 2021?

A. Yes. This data is shown on page 4 of Appendix I.

Q. How were the outage factors for this period developed?

A. The unplanned outage factors were developed using the actual historical full and partial outage event data for each of the units. The historical unplanned outage factor of each generating unit was adjusted, as necessary, to eliminate non-recurring events and recognize the effect of planned outages to arrive at the projected factor for the period January through December 2021.

Q. Please describe the significant planned outages for the January through December 2021 period.

A. Planned outages at FPL's nuclear units are the most significant in relation to fuel cost recovery. St. Lucie Unit 1 is scheduled to be out of service from April 12, 2021 until May 16, 2021, or 34 days during the period. St Lucie Unit 2 is scheduled to be out of service from August 30, 2021 until October 4, 2021, or 35 days during the period. Turkey Point Unit 3 is scheduled to be out of service from October 4, 2021 until November 2, 2021, or 29 days during the period.

Q. Please identify any changes to FPL's fossil generation capacity projected to take place during the January through December 2021 period.

A. As shown in FPL's 2020 Ten Year Power Plant Site Plan (Table ES-1, page 16), FPL projects a net increase in its 2021 summer firm capacity of 577 MW. This increase is primarily related to the addition of 539 MW of firm capacity of solar generation.

WHOLESALE (OFF-SYSTEM) POWER AND PURCHASED POWER TRANSACTIONS

Q. Are you providing the projected wholesale (off-system) power sales and purchased power transactions forecasted for January through December 2021?

A. Yes. This data is shown on Schedules E6, E7, E8, and E9 of Appendix II of this filing.

Q. In what types of wholesale (off-system) power transactions does FPL engage?

A. FPL purchases power from the wholesale market when it can displace higher cost generation with lower cost power from the market. FPL will also sell excess power into the market when its cost of generation is lower than the market. FPL's customers benefit from both purchases and sales as savings on purchases and gains on sales are credited to customers through the Fuel Cost Recovery Clause. Power purchases and sales are executed under specific tariffs that allow FPL to transact with a given entity. Although FPL primarily transacts on a short-term basis (hourly and daily transactions), FPL continuously searches for all opportunities to lower fuel costs through purchasing and selling wholesale power, regardless of the duration of the transaction.

Q. Please describe the method used to forecast wholesale (off-system) power purchases and sales.

A. The quantity of wholesale (off-system) power purchases and sales are projected based upon estimated generation costs, generation availability, fuel availability, expected market conditions and historical data.

Q. What are the forecasted amounts and costs of wholesale (off-system) power sales?

A. FPL has projected 2,598,470 MWh of wholesale (off-system) power sales for the period of January through December 2021. The projected fuel cost related to these sales is $52,303,995. The projected transaction revenue from these sales is $84,634,486. After taking into account the transmission costs and capacity revenues for those sales, the projected gain is $25,272,200.

Q. In what document are the fuel costs for wholesale (off-system) power sales transactions reported?

A. Schedule E6 of Appendix II provides the total MWh of energy, total dollars for fuel adjustment, total cost and total gain for wholesale (off-system) power sales.

Q. What are the forecasted amounts and costs of wholesale (off-system) power purchases for the January to December 2021 period?

A. The costs of these economy purchases are shown on Schedule E9 of Appendix II. For the period, FPL projects it will purchase a total of 347,180 MWh at a cost of $9,019,180. If FPL generated this energy, FPL estimates that it would cost $10,519,080. Therefore, these purchases are projected to result in savings of $1,499,900.

Q. Does FPL have additional agreements for the purchase of electric power and energy that are included in your projections?

A. Yes. FPL purchases energy under two contracts with the Solid Waste Authority of Palm Beach County ("SWA"). In addition, FPL contracts to purchase and sell nuclear energy under the St. Lucie Plant Nuclear Reliability Exchange Agreements with Orlando Utilities Commission ("OUC") and Florida Municipal Power Agency. Lastly, FPL purchases energy and capacity from Qualifying Facilities under existing tariffs and contracts.

Q. Please provide the projected energy costs to be recovered through the Fuel Cost Recovery Clause for the power purchases referred to above during the January through December 2021 period.

A. Energy purchases under the SWA agreements are projected to be 904,028 MWh for the period at an energy cost of $27,268,678. FPL's cost for energy purchases under the St. Lucie Plant Reliability Exchange Agreements is a function of the operation of St. Lucie Unit 2 and the fuel costs to the owners. For the period, FPL projects purchases of 573,685 MWh at a cost of $2,641,298. These projections are shown on Schedule E7 of Appendix II.

In addition, as shown on Schedule E8 of Appendix II, FPL projects that purchases from Qualifying Facilities for the period will provide 312,315 MWh at a cost of $5,919,852.

Q. How does FPL develop the projected energy costs related to purchases from Qualifying Facilities?

A. For those contracts that entitle FPL to purchase "as-available" energy, FPL used its fuel price forecasts as inputs to the GenTrader model to project FPL's avoided energy cost that is used to set the price of these energy purchases each month. For those contracts that enable FPL to purchase firm capacity and energy, the applicable Unit Energy Cost mechanisms prescribed in the contracts are used to project monthly energy costs.

Q. What are the forecasted amounts and cost of energy being sold under the St. Lucie Plant Reliability Exchange Agreement?

A. FPL projects to sell 571,679 MWh of energy at a cost of $2,826,064. These projections are shown on Schedule E6 of Appendix II.

<u>**HEDGING/ RISK MANAGEMENT PLAN**</u>

Q. Has FPL filed a Hedging Activity Final True-Up Report for 2019 or a risk management plan for 2021, consistent with the Hedging Order Clarification Guidelines, as required by Order No. PSC-08-0667-PAA-EI issued on October 8, 2008?

A. No. FPL's fuel hedging program is under a moratorium. Therefore, FPL had no hedging activity to report for 2019, had no hedging activity in 2020, and does not plan to hedge in 2021.

THE INCENTIVE MECHANISM

Q. What were the results of FPL's asset optimization activities under the Incentive Mechanism in 2019?

A. FPL's asset optimization activities in 2019 delivered total benefits of $55,249,313. The total gains exceeded the sharing threshold of $40 million and, therefore, the gains above $40 million will be shared between customers and FPL on a 40%/60% basis, respectively. In total, customers will receive $45,924,933 (net of FPL's share of the gain above the $40 million threshold, and after incremental personnel, software, and hardware expenses are removed), and FPL will receive $9,149,588. FPL's share of the gain is included for recovery in FPL's 2021 FCR Clause factors.

Q. Did the Incentive Mechanism allow FPL to deliver greater value to customers in 2019?

A. Yes. I have compared how customers would have fared under the prior wholesale-sales sharing mechanism with the results FPL has achieved under the Incentive Mechanism. For the purpose of this comparison, I have included the same savings of approximately $40.6 million from optimization activities for power sales, power purchases and releases of electric transmission capacity under both mechanisms, as FPL was engaging in those activities prior to the Commission's approval of the Incentive Mechanism. For those savings, the previous sharing mechanism would have yielded net benefits to FPL's customers of $40.4 million, while FPL would have received $0.2 million in benefits because the three-year rolling average threshold for wholesale sales would have been exceeded.

In contrast, under the Incentive Mechanism, FPL also is incented to pursue beneficial natural gas transportation, storage and trading activities. These activities generated slightly more than $16.4 million of additional savings in 2019. When one takes into account these additional savings, less FPL's recovery of incremental optimization costs, the result is that FPL's customers received slightly more than $45.9 million of savings under the Incentive Mechanism. This is $5.5 million more than customers would have received if the prior sharing mechanism were still in effect, clear proof that the Incentive Mechanism is working to deliver added value for customers as FPL and the Commission envisioned when it was approved.

Q. Has FPL included in its 2021 FCR factors, projections of the savings that it will achieve under the Incentive Mechanism?

A. Yes. FPL has included projections for savings on wholesale power purchases (Schedule E9), projections for gains on wholesale power sales (Schedule E6), and projections for other types of asset optimization measures (Schedule E3) for 2021.

Q. Has FPL included in its 2021 FCR factors, projections of the Incremental Optimization Costs that it will incur under the Incentive Mechanism?

A. Yes. FPL has included in its 2021 FCR factors, Incremental Optimization Costs from two categories: (i) incremental personnel, software and hardware costs associated with managing the various asset optimization activities, and

(ii) variable power plant O&M ("VOM") costs associated with wholesale economy sales and purchases.

Q. Please describe the costs that are included in FPL's projections for incremental personnel, software and hardware expenses.

A. FPL projects to incur incremental expenses of $451,676 in 2021 for the salaries and expenses related to employees who were added in 2013 to support the Incentive Mechanism.

Q. Please describe the costs that are included in FPL's projections for VOM expenses.

A. Consistent with Paragraph 15 of the 2016 Base Rate Settlement Agreement, FPL has included for recovery in its 2021 FCR factors, VOM expenses that reflect the netting of economy sales and purchases. As shown on Schedules E6 and E9 of Appendix II, FPL projects to sell 2,598,470 MWh and purchase 347,180 MWh of economy power. Therefore, applying FPL's VOM rate of $0.65/MWh, FPL projects to incur VOM expenses of $1,689,006 associated with its economy sales and to avoid ($225,667) with its economy purchases. FPL has included for recovery the net of these two figures, $1,463,339 (Schedule E2, Sum of Line Nos. 14 and 15), in its 2021 FCR factors.

Q. Does this conclude your testimony?

A. Yes it does.

(Whereupon, prefiled direct testimony of Charles Rote was inserted.)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF CHARLES R. ROTE

DOCKET NO. 20200001-EI

MARCH 16, 2020

Q. Please state your name and business address.

A. My name is Charles R. Rote, and my business address is 700 Universe Boulevard, Juno Beach, Florida 33408.

Q. By whom are you employed and in what capacity?

A. I am employed by Florida Power & Light Company ("FPL"), as Business Services Director in the Power Generation Division.

Q. Please summarize your educational background and professional experience.

A. I graduated from DePauw University with a Bachelor's degree in Industrial Psychology in 1991. I subsequently earned a Master of Business Administration from Pace University in New York in 1994. I am a Certified Public Accountant in the state of New York. Prior to joining FPL in 2009, I held various auditing positions at Price Waterhouse LLP and Pfizer Inc. From 1999 to 2009, I worked for Rinker Materials (acquired by Cemex in 2008) in various audit, accounting and development capacities. I have been in my current role at FPL since 2009 where I have responsibility for all budgeting, forecasting, regulatory and internal controls activities for FPL's fossil generating assets. Since 2013, I have also overseen the preparation and filing of the Generating Performance Incentive Factor ("GPIF") documents including testimony, exhibits, audits and discovery.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to report FPL's actual 2019 performance for Equivalent Availability Factor ("EAF") and Average Net Operating Heat Rate ("ANOHR") for the twelve generating units used to determine its GPIF and to calculate the resulting GPIF reward. I compared the performance of each unit to the targets approved in the final Commission Order No. PSC-2018-0610-FOF-EI issued December 26, 2018 for the period January through December 2019, and performed the reward/penalty calculations prescribed by the GPIF Manual. My testimony presents the result of these calculations: $16,250,444 of fuel savings to FPL's customers as a result of the availability and efficiency of FPL's GPIF generating units, and a GPIF reward of $8,125,681.

Q. Have you prepared, or caused to have prepared under your direction, supervision, or control any exhibits in this proceeding?

A. Yes. Exhibit CRR-1 shows the reward/penalty calculations. Page 1 of Exhibit CRR-1 is an index to the contents of the exhibit.

Q. Please explain in general terms how the total GPIF reward/penalty amount was calculated.

A. The steps involved in making this calculation are provided in Exhibit CRR-1. Page 2 provides the GPIF Reward/Penalty Table (Actual), which shows an overall GPIF performance point value of +3.4115, $16,250,444 in fuel savings and a GPIF reward of $8,125,681. Page 3 provides the calculation of the maximum allowed incentive dollars as approved by Commission Order No. PSC-13-0665-FOF-EI issued December 18, 2013. The calculation of the system actual GPIF performance points is shown on page 4. This page lists each GPIF unit, the unit's EAF and ANOHR, the weighting factors, and the associated GPIF unit points.

Page 5 is the actual EAF and adjustments summary. This page, in columns 1 through 5, lists each of the twelve GPIF units, the actual outage factors and the actual EAF for each unit. Column 6 is the adjustment for planned outage variation. Column 7 is the adjusted actual EAF, which is calculated on page 6. Column 8 is the target EAF. Column 9 contains the Generating Performance Incentive Points for availability as determined by interpolating from the tables shown on pages 8 through 19. These tables are based on the targets and target ranges previously approved by the Commission.

Continuing with Exhibit CRR-1, page 7 shows the adjustments to ANOHR. For each GPIF unit it shows, in columns 2 through 4, the target heat rate formula, and the actual net output factor ("NOF") and ANOHR for all units. Since heat rate varies with NOF, it is necessary to determine both the target and actual heat rates at the same NOF. This adjustment provides a common basis for comparison purposes and is shown numerically for each GPIF unit in columns 5 through 8. Column 9 contains the Generating Performance

Incentive Points as determined by interpolating from the tables shown on pages 8 through 19. These tables are based on the targets and target ranges approved by the Commission.

Q. Please explain the primary reason FPL will receive a reward under the GPIF for the January through December 2019 period.

A. The primary reason that FPL will receive a reward for the period is that adjusted actual EAFs for ten out of the twelve GPIF units were better than their targets. In addition, four out of the twelve GPIF units operated with an adjusted actual ANOHR that was below the ±75 Btu/kWh dead band.

Q. Please summarize each nuclear unit's performance as it relates to the EAF.

A. St. Lucie Unit 1 operated at an adjusted actual EAF of 71.2%, compared to its target of 84.6%. This results in -10.0 points, which corresponds to a GPIF penalty of $2,079,355.

St. Lucie Unit 2 operated at an adjusted actual EAF of 100.0%, compared to its target of 93.6%. This results in +10.0 points, which corresponds to a GPIF reward of $1,924,535.

Turkey Point Unit 3 operated at an adjusted actual EAF of 99.1% compared to its target of 93.6%. This results in +10.0 points, which corresponds to a GPIF reward of $1,798,297.

Turkey Point Unit 4 operated at an adjusted actual EAF of 87.6% compared to its target of 81.3%. This results in +10.0 points, which corresponds to a GPIF reward of $1,631,567.

In total, the nuclear units' EAF performance results in a GPIF reward of $3,275,044.

Q. Please summarize each nuclear unit's performance as it relates to ANOHR.

A. The St. Lucie Unit 1 adjusted actual ANOHR is 10,397 Btu/kWh compared to its target of 10,404 Btu/kWh. This ANOHR is within the ±75 Btu/kWh dead band around the projected target; therefore, there is no GPIF reward or penalty.

The St. Lucie Unit 2 adjusted actual ANOHR is 10,248 Btu/kWh compared to its target of 10,268 Btu/kWh. This ANOHR is within the ±75 Btu/kWh dead band around the projected target; therefore, there is no GPIF reward or penalty.

The Turkey Point Unit 3 adjusted actual ANOHR is 10,594 Btu/kWh compared to its target of 11,021 Btu/kWh. This ANOHR is better than the ±75 Btu/kWh dead band around the projected target. This results in +10.0 points, which corresponds to a GPIF reward of 335,841.

Turkey Point Unit 4 adjusted actual ANOHR is 10,942 Btu/kWh compared to its target of 10,954 Btu/kWh. This ANOHR is within the ±75 Btu/kWh dead band around the projected target; therefore, there is no GPIF reward or penalty.

In total, the nuclear units' heat rate performance results in a GPIF reward of $335,841.

Q. What is the total GPIF reward for FPL's nuclear units?

A. $3,610,885.

Q. Please summarize the performance of FPL's fossil units.

A. Regarding EAF performance, seven of the eight fossil generating units performed better than their availability targets as shown on Exhibit CRR-1, page 5, resulting in a combined reward of $2,908,955. The other one performed worse than its availability target as shown on Exhibit CRR-1, page 5, resulting in a penalty of $477,561. Thus, the total fossil units' EAF performance results in a net GPIF reward of $2,431,394.

Regarding ANOHR, four of the eight fossil units operated with ANOHRs that were within the ±75 Btu/kWh dead band so there were no incentive rewards or penalties. Another three operated below the dead band so they received a combined reward of $3,610,169 and one unit operated above the dead band so it received a penalty of $1,526,766. Thus, the total fossil units' heat rate performance results in a net GPIF reward of $2,083,403.

Q. What is the total GPIF reward/penalty for FPL's fossil units?

A. The net GPIF fossil availability performance reward of $2,431,394 plus the net GPIF heat rate fossil performance reward of $2,083,403 results in a total GPIF reward for FPL's fossil units of $4,514,797.

Q. To recap, what is the total GPIF result for the period January through December 2019?

A. The total GPIF result for the period January through December 2019 is $16,250,444 of fuel savings to FPL's customers as a result of the availability and efficiency of FPL's GPIF generating units, and a GPIF reward of $8,125,681.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF CHARLES R. ROTE

DOCKET NO. 20200001-EI

SEPTEMBER 3, 2020

Q. Please state your name and business address.

A. My name is Charles R. Rote, and my business address is 700 Universe Boulevard, Juno Beach, Florida 33408.

Q. By whom are you currently employed and in what capacity?

A. I am employed by Florida Power & Light Company (FPL) as the Business Services Director in the Power Generation Division of FPL, where I am responsible for budgeting, forecasting, regulatory reporting and financial internal controls for FPL's fossil generating assets.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present FPL's generating unit equivalent availability factor (EAF) targets and average net operating heat rate (ANOHR) targets used in determining the Generating Performance Incentive Factor (GPIF) for the period January through December 2021.

Q. Have you prepared, or caused to have prepared under your direction, supervision, or control, any exhibits in this proceeding?

A. Yes, I am sponsoring Exhibit CRR-2. This Exhibit supports the development of the 2021 GPIF EAF and ANOHR targets. The first page of this exhibit is an index to its contents. All other pages are numbered according to the GPIF Manual as approved by the Commission.

Q. Please summarize the 2021 system targets for EAF and ANOHR for the units to be considered in establishing the GPIF for FPL.

A. For the period of January through December 2021, FPL projects a weighted system equivalent planned outage factor ("EPOF") of 6.3% and a weighted system equivalent unplanned outage factor ("EUOF") of 7.6%, which yield a weighted system EAF target of 86.1%. The targets for this period reflect planned refuelings for St. Lucie Units 1 and 2 and Turkey Point Unit 3. FPL also projects a weighted system ANOHR target of 7,290 Btu/kWh for the period January through December 2021. These targets represent fair and reasonable values. Therefore, FPL requests that the targets for these performance indicators be approved by the Commission.

Q. Have you established individual target levels of performance for the units to be considered in establishing the GPIF for FPL?

A. Yes, I have. Exhibit CRR-2, pages 6 and 7, contains the information summarizing the individual targets and ranges for EAF and ANOHR for each of the thirteen generating units that FPL proposes to be considered as GPIF units for the period January through December 2021. All of these targets have been derived utilizing the accepted methodologies adopted in the GPIF Manual.

Q. Please summarize FPL's methodology for determining EAF targets.

A. The GPIF Manual requires that the EAF target for each unit be determined as the difference between 100% and the sum of the EPOF and EUOF. The EPOF for each unit is determined by the duration and magnitude of the planned outage, if any, scheduled for the projected period. The EUOF is determined by the sum of the historical average equivalent forced outage factor and the historical equivalent maintenance outage factor. The EUOF is then adjusted to reflect recent or projected unit overhauls following the projection period.

Q. Please summarize FPL's methodology for determining ANOHR targets.

A. To develop the ANOHR targets, a set of curves that reflect historical ANOHR and unit net output factors are developed for each GPIF unit. The historical data is analyzed for any unusual operating conditions and changes in equipment that affect the predicted heat rate. A regression equation is calculated and a statistical analysis of the historical ANOHR variance with respect to the best fit curve is also performed to identify unusual observations. The resulting equation is used to project ANOHR for the unit using the net output factor from the production costing simulation program, GenTrader. This projected ANOHR value is then used in the GPIF tables and in the calculations to determine the possible fuel savings or losses due to improvements or degradations in heat rate performance. This process is consistent with the GPIF Manual.

Q. How did you select the units to be considered when establishing the GPIF for FPL?

A. In accordance with the GPIF Manual, the GPIF units selected are responsible for no less than 80% of the estimated system net generation. The estimated net generation for each unit is taken from the GenTrader model, which forms the basis for the projected levelized fuel cost recovery factor for the period. In this case, the thirteen units which FPL proposes to use for the period January through December

2021 represent the top 82.3% of the total forecasted system net generation for this period excluding the Okeechobee Clean Energy Center. This unit came into service in April 2019 and was excluded from the GPIF calculation because there is insufficient historical data to include it. Consistent with the GPIF Manual, this unit will be considered in the GPIF calculations once FPL has enough operating history to use in projecting future performance.

Q. Do FPL's 2021 EAF and ANOHR performance targets as shown on Exhibit CRR-2 represent reasonable levels of generation availability and efficiency?

A. Yes, they do.

Q. Does this conclude your testimony?

A. Yes, it does.

(Whereupon, prefiled direct testimony of Liz Fuentes was inserted.)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Fuel and Purchase Power Cost Recovery Clause with Generating Performance Incentive Factor	Docket No: 20200001-EI

DECLARATION OF LIZ FUENTES

1. My name is Liz Fuentes, and my business address is Florida Power & Light Company ("FPL"), 9250 West Flagler Street, Miami, Florida, 33174.

2. I graduated from the University of Florida in 1999 with a Bachelor of Science Degree in Accounting. That same year, I was employed by FPL. During my tenure at the Company, I have held various accounting and regulatory positions of increasing responsibility with the majority of my career focused in regulatory accounting and the calculation of revenue requirements. Specifically, I have provided accounting support in multiple FPL retail base rate filings and other regulatory dockets filed at the Florida Public Service Commission ("FPSC" or the "Commission") as well as the Federal Energy Regulatory Commission ("FERC"). My responsibilities have included the management of the accounting for FPL's cost recovery clauses and the preparation, review and filing of FPL's monthly Earnings Surveillance Reports ("ESR") at the FPSC. I am a Certified Public Accountant ("CPA") licensed in the Commonwealth of Virginia and am a member of the American Institute of CPAs. I have previously filed testimony before the Commission for FPL's Solar Base Rate Adjustments ("SoBRAs") related to the solar photovoltaic projects placed in service in 2018 and 2020 (Docket Nos. 20170001-EI and 20190001-EI) and request for approval of the Indiantown Transaction (Docket No. 160154-EI).

3. I am employed by FPL as Senior Director, Regulatory Accounting.

4. The purpose of my declaration is to provide the final jurisdictional revenue requirements for the 2018 SoBRA approved by the Commission in Order No. PSC-2018-0028-FOF-EI, Docket No. 20180001-EI, and placed into service during 2018 (the "2018 Project"). The final jurisdictional revenue requirement computation is based on actual capital costs for the 2018 Project as required by FPL's Stipulation and Settlement Agreement approved by the Commission in Order No. PSC-16-0560-AS-EI, Docket No. 160021-EI, issued on December 15, 2016 ("Settlement Agreement").

5. Paragraph 10(g) of the Settlement Agreement states the following:

"In the event that the actual capital expenditures are less than the projected costs used to develop the initial SoBRA factor, the lower figure shall be the basis for the full revenue requirements and a one-time credit will be made through the CCR Clause. In order to determine the amount of this credit, a revised SoBRA Factor will be computed using the same data and methodology incorporated in the initial SoBRA factor, with the exception that the actual capital expenditures will be used in lieu of the capital expenditures on which the Annualized Base Revenue Requirement was based."

6. As reflected on page 1 of Attachment LF-1, the final jurisdictional annualized revenue requirement associated with the 2018 SoBRA is $55.797 million.

7. The final revenue requirement computation for the 2018 SoBRA is based on the same inputs used for the initial 2018 SoBRA Factor included in my testimony filed on August 24, 2017, Docket No. 20170001-EI, and approved by this Commission in Order No. PSC-2018-0028-FOF-EI, except for capital costs. As reflected on page 2 of Attachment LF-1, the projected total per book capital costs of $442.585 million used in the initial 2018 SoBRA Factor were replaced with the actual total per book costs of $411.805 million, resulting in a decrease in revenue

requirements of $4.094 million from the initial 2018 SoBRA calculation. The refund calculation associated with this decrease in revenue requirements is discussed in FPL witness Edward Anderson's declaration.

8. Under penalties of perjury, I declare that I have read the foregoing declaration and that the facts stated in it are true to the best of my knowledge and belief.

Liz Fuentes

LIZ FUENTES

Date: 8/31/2020

(Whereupon, prefiled direct testimony of Edward J. Anderson was inserted.)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Fuel and Purchase Power Cost Recovery Clause and Generating Performance Incentive Factor	Docket No. 20200001-EI

DECLARATION OF EDWARD J. ANDERSON

1. My name is Edward J. Anderson, and my business address is Florida Power & Light Company, 700 Universe Boulevard, Juno Beach, Florida 33408. I have personal knowledge of the matters stated in this declaration.

2. I am employed by Florida Power & Light Company ("FPL" or the "Company") as Manager-Regulatory Rate Development.

3. I hold a Bachelor of Arts in Economics and Business, from the Virginia Military Institute. In November 2016, I joined FPL as Principal-Rate Development within the Company's Regulatory Affairs Organization, and assumed my current role in March 2018. Prior to joining FPL, I was employed by Dominion Energy for fourteen years. From 2003 to 2007, I worked within Dominion's Trading and Marketing Organization as a Business Operations Support Associate and Power Market Analyst. My responsibilities included Power Pool (PJM and NE-ISO) reconciliation, analysis, and trading support. In 2007, I was promoted to Hourly Trader where I was responsible for managing and optimizing the hourly operations of Dominion's merchant power plant assets in PJM and NE-ISO. From 2008 to 2016, I worked within Dominion's State Regulation Department as a senior level Regulatory Pricing Analyst and Regulatory Advisor. My responsibilities included providing support and analysis as they related to rate design for all base and rider regulatory filings, and I was the Company's rates witness for several generation adjustment and fuel rate proceedings.

4. The purpose of my declaration is to provide the revisions to FPL's Solar Base

Rate Adjustment ("SoBRA") Factor for true-up of the 2018 Project revenue requirement, the amount to be refunded through the Capacity Cost Recovery Clause ("CCRC"), and the corresponding prospective true-up rates to become effective January 1, 2021. If approved, the Company will submit revised tariff sheets reflecting the Commission-approved charges.

5. FPL is employing the identical mechanism employed to true-up the capital expenditures associated with the 2017 Solar Project, as well as the true-ups for Cape Canaveral, and the Port Everglades Energy Center.

6. As presented on page 1 of Attachment LF-1 to the Declaration of Liz Fuentes, the 2018 Project final jurisdictional annualized base revenue requirement based on the actual capital costs for the 2018 Project is $55.797 million.

7. Except for the revenue requirement associated with the actual capital costs, the revised 2018 SoBRA Factor is computed using the same data used in the computation of the initial 2018 SoBRA Factor. This data includes billed retail base revenues from the sales of electricity and unbilled retail base revenues in the amount of $6,518.299 million, as shown in the 2018 SoBRA Filing.

8. The revised 2018 SoBRA Factor using the updated revenue requirement of $55.797 million is 0.856%. The computation of this revised factor is provided in Attachment EJA-1, page 1 of 3.

9. Pursuant to the Settlement Agreement and consistent with the Initial SoBRA Filing, once the 2018 Solar Project actual capital costs are known, if the actual capital costs are less than the projected costs used to develop the initial 2018 SoBRA Factor, a one-time credit is to be made through the Capacity Clause. The difference between the cumulative base revenues that have been collected since the implementation of the initial 2018 SoBRA Factor on March 1, 2018 through December 31, 2020, and the cumulative base revenues that would have resulted

if the revised 2018 SoBRA Factor had been implemented on March 1, 2018 will be credited to customers through the CCRC with interest through December 31, 2020 at the 30-day commercial paper rate as specified in Rule 25-6.109. The amount of the refund with interest for the 2018 Solar Project since the project entered commercial service is $12.402 million and is shown in Attachment EJA-1, pages 2-3.

10. In accordance with Section 10(g) of the Settlement Agreement, base rates will also be adjusted to reflect the revised 2018 SoBRA Factor effective January 1, 2021 to account for this revision in jurisdictional revenue requirements going forward. Attachments EJA-2 through EJA-4 present the calculations and resulting rates for this change.

11. Attachment EJA-5 provides projected bill changes. The typical bill projections reflect proposed base and clause changes to become effective on January 1, 2021.

12. Under penalties of perjury, I declare that I have read the foregoing declaration and that the facts stated in it are true to the best of my knowledge and belief.

Edward J. Anderson

Date: 9/1/2020

(Whereupon, prefiled direct testimony of Curtis D. Young was inserted.)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

Docket No. 20200001-EI
Fuel and Purchased Power Cost Recovery Clause
Direct Testimony of
Curtis Young
(2019 Final True-Up)
on behalf of
<u>Florida Public Utilities Company</u>

Q. Please state your name and business address.

A. Curtis Young, 1635 Meathe Road, West Palm Beach, Florida 33411.

Q. By whom are you employed?

A. I am employed by Florida Public Utilities Company.

Q. Could you give a brief description of your background and business experience?

A. I am the Senior Regulatory Analyst for Florida Public Utilities Company. I have performed various accounting and analytical functions including regulatory filings, revenue reporting, account analysis, recovery rate reconciliations and earnings surveillance. I'm also involved in the preparation of special reports and schedules used internally by division managers for decision making projects. Additionally, I coordinate the gathering of data for the FPSC audits.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present the calculation of the final remaining true-up amounts for the period January 2019 through December 2019.

Q. Have you included any exhibits to support your testimony?

A. Yes. Exhibit________ (CDY-1) consists of Schedules A, C1 and E1-B for the Consolidated Electric Division. These schedules were prepared from the records of the company.

Q. What has FPUC calculated as the final remaining true-up amounts for the period January 2019 through December 2019?

A. For the Consolidated Electric Division the final remaining true-up amount is an over recovery of $1,631,177.

Q. How was this amount calculated?

A. It is the difference between the actual end of period true-up amount for the January through December 2019 period and the total true-up amount to be collected or refunded during the January - December 2020 period.

Q. What was the actual end of period true-up amount for January - December 2019?

A. For the Consolidated Electric Division it was $303,275 under recovery.

Q. What was the Commission-approved amount to be collected or refunded during the January – December 2020 period?

A. A consolidated under-recovery of $1,934,452 to be collected.

Q. Does this conclude your direct testimony?

A. Yes, it does.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 20200001-EI: Fuel and purchased power cost recovery clause with generating performance incentive factor.

Direct Testimony of Curtis D. Young (Estimated/Actual)

On Behalf of Florida Public Utilities Company

Q. Please state your name and business address.

A. My name is Curtis D. Young. My business address is 1635 Meathe Drive, West Palm Beach, Florida 33411.

Q. By whom are you employed?

A. I am employed by Florida Public Utilities Company ("FPUC" or "Company")

Q. Describe briefly your education and relevant professional background.

A. I have a Bachelor of Business Administration Degree in Accounting from Pace University in New York City, New York. I am the Senior Regulatory Analyst for Florida Public Utilities Company. I have performed various accounting and analytical functions including regulatory filings, revenue reporting, account analysis, recovery rate reconciliations and earnings surveillance. I'm also involved in the preparation of special reports and schedules used internally by division managers for decision making projects. Additionally, I coordinate the gathering of data for the FPSC audits..

Q. Have you previously testified in this Docket?

A. Yes, I have.

Q. What is the purpose of your testimony at this time?

A. I will briefly describe the basis for the Company's computations made in preparation of the schedules being submitted in this docket.

Q. Which of the Staff's schedules is the Company providing in support of this filing?

A. I am attaching Schedules E1-A, E1-B, and E1-B1 as part of Exhibit CDY-2. Schedule E1-B shows the Calculation of Purchased Power Costs and Calculation of True-Up and Interest Provision for the period January 2020 – December 2020 based on 6 Months Actual and 6 Months Estimated data. I have also prepared Exhibit CDY-3, which is comprised of revised Schedules A-1, A-2, A-4, A-8, A-8a and A-9 for each month from January 2020 through June 2020. The purpose for the inclusion of these schedules will be addressed in my testimony.

Q. Were these schedules completed by you or under your direct supervision?

A. The schedules were completed under my direct supervision.

Q. What was the final remaining true-up amount for the period January 2019 – December 2019?

A. The final remaining true-up amount was an under-recovery of $2,017,896.

Q. What is the estimated true-up amount for the period January 2020 – December 2020?

A. The estimated true-up amount is an over-recovery of $1,252,729.

Q. What is the total true-up amount estimated to be collected, or refunded for the period January 2021 – December 2021?

A. At the end of December 2020, based on six months actual and six months estimated, the Company estimates it will under-recover $765,167 in purchased power costs, which will be collected from January 2021 – December 2021.

Q. Has the Company made any revisions to its 2020 estimated six month projection data?

A. Yes, we made changes to the estimated fuel costs since our original projection filing for 2020. Our "special costs" which consists primarily of consultant costs and legal fees have been running lower than anticipated throughout the first half of the year and are expected to decrease by approximately $55,000 for the remainder of the year. Therefore, we have updated our fuel costs to more accurately reflect current billing data from our contracted services.

Q. The beginning true-up balance from your Schedule E1-b differs from the amount that appeared in your Final True-Up Amount for 2019, please explain?

A. It was discovered that our monthly Fuel filing for December 2018 as well as the 2018 Final True-up filing had errors with regards to Fuel Revenues. In that fourth quarter, we were still in the midst of restoring services to our many customers impacted by damages resulting from Hurricane Michael. Part of this process entailed applying several adjusting transactions within our billing system. The Company did not bill its customers in the affected areas of the hurricane during the months of October and November. In December, a majority of the services had been restored and the Company resumed its billing processes. Subsequently, due to the suspension of billing for a specific area, adjustments were made to the billing system and accounting financials to correct any billing issues. Around the same time, the

Company also received Commission approval to apply a portion of its 2018 Tax Cuts and Jobs Act settlement to its fuel and purchased power cost under- recovery. In the course of preparing the monthly fuel filing for December 2018, some adjustments were not accurately reflected in the fuel revenues causing the true-up to be overstated. This finding was not immediately detected and the discrepancy carried forward in our reported fuel filings, which necessitated FPUC performing a thorough reconciliation to correct the fuel filings and determine the appropriate true-up balance.

Q. Is the $3,952,348 under-recovery that appears as your beginning true-up balance on your Schedule E1-b the correct final true-up-amount for 2019?

A. Yes.

Q. **How will this correction be implemented in this filing?**

A. I have prepared revised monthly Fuel true-up filing for each of the months from January 2020 to June 2020 in Exhibit CDY-3 of this filing to further illustrate the monthly computations of the 2020 true-up recoveries.

Q. **In previous years FPUC explored other opportunities to provide power supply for its customers. Has FPUC continued to explore other opportunities?**

A. Yes. FPUC is continuing to look into other sources of power supply that will provide low cost, resilient and reliable energy to customers.

Q. **Would you please discuss the opportunities FPUC has been investigating?**

A. Yes. FPUC is continuing to explore both Solar Photovoltaic (solar) and Combined Heat and Power (CHP) technologies with the goal of providing low cost, resilient and reliable energy to customers. Solar opportunities are being explored in both the Northeast and Northwest Divisions and are under consideration at this time. In our Northeast Division, significant effort has been focused on the development of a second CHP on Amelia Island. This project will be similar in size and operation to the existing Eight Flags Energy project that began commercial operation in 2016. Amelia Island Energy (AIE), as it will be named, will be located approximately one mile from Eight Flags Energy at a separate mill on Amelia Island. This CHP will provide electrical energy to the FPUC grid and thermal energy in the form of steam/hot water to the mill. Preliminary engineering has been completed, operating agreements have been developed and air permitting is underway at this time. AIE will provide low cost energy to our customers while improving the resiliency and reliability to the FPUC grid on Amelia Island.

Q. Has the Company incurred any costs during the preliminary stages of this project?

A. Yes, the Company has engaged the consulting firms of Pierpont and McLelland LLC and Sterling Energy Services LLC and well as the law firm of Gunster, Yoakley and Stewart PA for their experienced expertise in the aforementioned processes. To date, the Company has incurred approximately $46,000 in the consulting and legal fees linked to this project and roughly estimate to spend another $50,000 by year-end 2020.

Q. When do you anticipate construction to begin on the AIE facility?

A. FPUC plans to seek Commission approval, must execute operating agreements, and obtain finalized air permits prior to ordering major equipment for the project. The Company's current schedule anticipates finalizing these steps later in 2020 with major equipment items anticipated to be ordered in early 2021. Commercial operation should occur within 1.5 years of ordering the major equipment.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 20200001-EI: FUEL AND PURCHASED POWER COST RECOVERY CLAUSE WITH GENERATING PERFORMANCE INCENTIVE FACTOR

Second Revised 2021 Projection Testimony of Curtis D. Young

On Behalf of

Florida Public Utilities Company

Q. Please state your name and business address.

A. My name is Curtis D. Young. My business address is 1635 Meathe Drive, West Palm Beach, FL 33411.

Q. By whom are you employed?

A. I am employed by Florida Public Utilities Company ("FPUC" or "Company") as Senior Regulatory Analyst.

Q. Could you give a brief description of your background and business experience?

A. I have a Bachelor of Business Administration Degree in Accounting from Pace University in New York City, New York. I am the Senior Regulatory Analyst for Florida Public Utilities Company. I have performed various accounting and analytical functions including regulatory filings, revenue reporting, account analysis, recovery rate reconciliations and earnings surveillance. I'm also involved in the preparation of special reports and schedules used internally by division managers for decision making projects. Additionally, I coordinate the gathering of data for the FPSC audits.

Q. Have you previously testified in this Docket?

A. Yes, I have.

Q. What is the purpose of your second revised testimony at this time?

A. My testimony will establish the "true-up" collection amount, based on actual January 2019 through June 2020 data and projected July 2020 through December 2021 data to be collected or refunded during January 2021 – December 2021. My testimony will also summarize the computations that are contained in revised composite exhibit CDY-4 supporting the January through December 2021 projected levelized fuel adjustment factors for its consolidated electric divisions which now include the flow-through of the over-collection of interim rates as addressed in the Company's position to Issue 3A of the prehearing statements. Additionally, these factors include a refund to customers per the settlement agreement for the corporate state income tax savings approved in Docket No. 20200033-EI by Order No. PSC-2020-0083-PAA-EI, issued on March 20, 2020

Q. What is the monetary impact of the over-collected interim rates adjustment to your 2020 true-up balance?

A. The adjustment is a $1,026,484 over-recovery to the true-up balance. This amount is comprised of $890,966 interim base rates collected from our customers from January through September 2020 and an additional $135,246 is estimated to be collected for October 2020. Finally, we compute $272 accrued interest for the period September through December 2020.

Q. What is the monetary impact of the state tax savings refund adjustment to your 2020 true-up balance?

A. The adjustment is a $35,851 over-recovery to the true-up balance. This amount is comprised of the NOI annual tax savings impact of $35,825 state tax savings and $26 of computed accrued interest.

Q. Were the schedules filed by the Company completed by you or under your direct supervision?

A. Yes, they were completed by me.

Q. Is FPUC providing the required schedules with this filing?

A. Yes. Included with this filing are the Revised Consolidated Electric Schedules E1, E1A, E2, E7, E8, and E10. These schedules are included in my Second Revised Exhibit CDY-4, which is appended to my testimony. Also included with this filing are the Revised Schedules E1-A, E1-B and E1-B1 as Revised Exhibit CDY-2. Revised Schedule E1-B shows the Calculation of Purchased Power Costs and Calculation of True-Up and Interest Provision for the period January 2020 – December 2020 based on 6 Months Actual and 6 Months Estimated data.

Q. Did you include costs in addition to the costs specific to purchased fuel in the calculations of your true-up and projected amounts?

A. Yes, included with our fuel and purchased power costs are charges for contracted consultants and legal services that are directly fuel-related and appropriate for recovery in the fuel and purchased power clause.

FPUC engaged Sterling Energy Services, LLC. ("Sterling") Christensen Associates Energy, LLC ("Christensen"), Locke Lord, LLP ("Locke"), and Pierpont and McClelland ("Pierpont") for assistance in the development and enactment of projects/programs designed to reduce their purchased power rates to its customers. The associated legal and consulting costs, included in the rate calculation of the Company's 2021 Projection factors, were not included in expenses during the last FPUC consolidated electric base rate proceeding and are not being recovered through base rates.

Mr. Cutshaw addresses these project assignments more specifically in his testimony.

Q. Please explain how these costs were determined to be recoverable under the fuel and purchased power clause?

A. Consistent with the Commission's policy set forth in Order No. 14546, issued in Docket No. 850001-EI-B, on July 8, 1985, the other fuel related costs included in the fuel clause are directly related to purchased power, have not been recovered through base rates.

Specifically, consistent with item 10 of Order 14546, the costs the Company has included are fuel-related costs that were not anticipated or included in the cost levels used to establish the current base rates. Similar expenses paid to Christensen and Associates associated with the design for a Request for Proposals of purchased power costs, and the evaluation of those responses, were deemed appropriate for recovery by FPUC through the fuel and purchased power clause in Order No. PSC-05-1252-FOF-EI, Item II E, issued in Docket No. 050001-EI. Additionally, in more recent Docket Nos. 20150001-EI, 20160001-EI, 20170001-EI, 20180001-EI, 20190001-EI and 20200001-EI the Commission determined that many of the costs associated with the legal and consulting work incurred by the Company as fuel related, particularly those costs related to the purchase power agreement review and analysis, were recoverable under the fuel clause. As the Commission has recognized time and again, the Company simply does not have the internal resources to pursue projects and initiatives designed to produce purchased power savings without engaging outside assistance for project analytics and due diligence, as well as negotiation and contract development expertise. Likewise, the Company believes that the costs addressed herein are appropriate for recovery through the fuel clause.

Q. **What are the final remaining true-up amounts for the period January – December 2019?**

A. The final remaining consolidated true-up amount was an under-recovery of $2,017,896.

Q. **What are the estimated true-up amounts for the period of January – December 2020?**

A. There is an estimated consolidated over-recovery of **$2,315,064.**

Q. **Please address the calculation of the total true-up amount to be**

collected or refunded during the January - December 2021 year?

A. The Company has determined that at the end of December 2020, based on six months actual and six months estimated, we will have a consolidated electric **over-recovery of $297,168.**

Q. What will the total consolidated fuel adjustment factor, excluding demand cost recovery, be for the consolidated electric division for the period?

A. The total fuel adjustment factor as shown on line 43, Schedule E-1 is **4.540¢** per KWH.

Q. Please advise what a residential customer using 1,000 KWH will pay for the period January - December 2021 including base rates, conservation cost recovery factors, gross receipts tax and fuel adjustment factor and after application of a line loss multiplier.

A. As shown on consolidated Schedule E-10 in Revised Composite Exhibit Number CDY-4, a residential customer using 1,000 KWH will pay **$128.30**. This is a decrease of **$8.61** below the previous period.

Q. Does this conclude your testimony?

A. Yes.

(Whereupon, prefiled direct testimony of P. Mark Cutshaw was inserted.)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 20200001-EI

FUEL AND PURCHASED POWER COST RECOVERY CLAUSE WITH GENERATING PERFORMANCE INCENTIVE FACTOR

2021 Projection Testimony of P. Mark Cutshaw

On Behalf of

Florida Public Utilities Company

Q. Please state your name and business address.

A. My name is P. Mark Cutshaw, 208 Wildlight Avenue, Yulee, Florida 32097.

Q. By whom are you employed?

A. I am employed by Florida Public Utilities Company ("FPUC" or "Company").

Q. Could you give a brief description of your background and business experience?

A. I graduated from Auburn University in 1982 with a B.S. in Electrical Engineering and began my career with Mississippi Power Company in June 1982. I spent 9 years with Mississippi Power Company and held positions of increasing responsibility that involved budgeting, as well as operations and maintenance activities at various Company locations. I joined FPUC in 1991 as Division Manager in our Northwest Florida Division and have since worked extensively in both the Northwest Florida and Northeast Florida Divisions. Since joining FPUC, my responsibilities have included all aspects of budgeting, customer service, operations and maintenance in both the Northeast and

Northwest Florida Divisions. My responsibilities also included involvement with Cost of Service Studies and Rate Design in other rate proceedings before the Commission as well as other regulatory issues. During 2019 I moved into my current role as Director, Generation and Pipeline Development.

Q. Have you previously testified before the Florida Public Service Commission ("Commission")?

A. Yes, I've provided testimony in a variety of Commission proceedings, including the Company's 2014 rate case, addressed in Docket No. 20140025-EI. Most recently, I provided written, pre-filed testimony in Docket No. 20190001-EI, the Commission's regular fuel cost recovery proceeding, and also provided both pre-filed and live testimony the prior year, in Docket No. 20180001-EI, the Commissions' regular fuel cost recovery. I have also been involved in and filed testimony in Docket No. 20191056 for the Limited Proceeding to Recover Incremental Storm Restoration Costs.

Q. What is the purpose of your direct testimony in this Docket?

A. My direct testimony addresses several aspects of the purchased power cost for our FPUC electric customers. This includes activities to investigate the potential for reduced purchase power costs, execution/amendment of purchased power agreements with Gulf Power Company ("Gulf")/Florida Power & Light ("FPL"), Combined Heat and Power ("CHP")generation supply located on Amelia Island and investigation into the opportunities of energy provided from solar and battery installations.

Q. What new opportunities has the Company implemented with the intent of achieving energy resiliency and reducing costs for its customers in its consolidated electric divisions?

A. The Company regularly pursues opportunities to achieve energy resiliency and reduced purchased power costs for the benefit of our customers. During 2018, FPUC began by executing a transmission interconnection agreement and a new purchased power agreement with Florida Power & Light (FPL) for our Northeast Florida Division. During 2019, a purchased power agreement with Gulf/FPL for our Northwest Florida Division was executed along with an amendment of the existing FPL purchased power agreement for our Northeast Florida Division.

Q. What is the status of the existing purchase power agreements in place with Gulf Power and FPL?

A. The existing agreement for our Northwest Florida Division with Gulf/FPL became effective January 1, 2020 and will continue in effect through December 31, 2026 unless extended by FPUC. The existing agreement for our Northeast Florida Division with FPL which became effective January 1, 2018 was amended in 2019 to continue in effect through the December 31, 2026 unless extended by FPUC.

Q. Can you provide background on the new purchased power agreement with FPL for the Northwest Florida Division and the amendment of the purchased power agreement for the Northeast Florida Division that became effective January 1, 2020?

A. Yes. Informal solicitations occurred with four providers that were capable of providing wholesale power to the Northwest Florida Division delivery points located in Jackson, Calhoun and Liberty Counties. Additional consideration was given to the ability to combine agreements for the Northeast and Northwest Florida Divisions in order to provide additional flexibility, reduce cost and increased energy resiliency between divisions. Proposals were received from four parties and the evaluation and discussions began immediately thereafter. Based on the differences in the bids submitted, the evaluation required additional time for soliciting additional information to allow for further assessment. After the evaluation was completed, FPL was determined to be the most appropriate selection and additional negotiations were conducted in order to develop a comprehensive purchased power agreement covering both the Northwest and Northeast Florida Divisions. On August 12, 2019, the "Native Load Firm All Requirements Power and Energy Agreement" ("Agreement") for the Northwest Florida Division was executed by both parties with an effective date of January 1, 2020 and continuing in effect through December 31, 2026. Additionally, on August 12, 2019, the "First Amendment to the Native Load Firm All Requirements Power and Energy Agreement" ("Amendment") for the Northeast Florida Division was executed by both parties. The "Amendment" will have the effect of extending the existing agreement for the Northeast Florida Division through December 31, 2026. Both the "Agreement" and "Amendment" include a provision that will allow FPUC the sole right to extend the agreements through December 31, 2030.

Q. Are there other efforts underway to identify projects that will lead to lower cost energy for FPUC customers?

A. Yes. FPUC continues to work with consultants, as well as project developers, to identify new projects and opportunities that can lead to increased energy resiliency and reduced fuel costs for our customers. We also continue to analyze the feasibility of energy production and supply opportunities that have been on our planning horizon for some time and noted in prior fuel clause proceedings, namely additional Combined Heat and Power (CHP) projects, potential Solar Photovoltaic ("PV") projects and associated utility scale battery projects.

More specifically, Pierpont & McLelland has been engaged to perform analysis and provide consulting services for FPUC as it relates to the structuring of, and operation under, the Company's power purchase agreements with the purpose of identifying measures that will minimize cost increases and/or provide opportunities for cost reductions. Locke Lord is a law firm with particular expertise in the regulatory requirements of the Federal Energy Regulatory Commission. Attorneys with the firm have provided legal guidance and oversight regarding the contracts and regulatory requirements for generation and transmission-related issues for the Northeast Florida Division. The Company's in-house experience in these areas is limited; thus, without this outside assistance, the Company's ability to pursue potential purchased power savings opportunities would be limited, as would its ability to properly evaluate proposals to meet our generation and transmission needs and ensure compliance with federal regulatory requirements.

Sterling Energy and Christensen Associates have been involved to assist the Company in the most cost-effective means of incorporating additional energy sources, such as power available from certain industrial customers, including customers with Combined Heat and Power ("CHP") capability, to further reduce the overall purchased power impact to all FPUC customers. Christensen Associates also assisted the Company with analysis regarding the purchase power agreements.

Q. Can you provide additional information on these CHP projects?

A. Yes. The success of the Eight Flags project has sparked interest in other CHP opportunities on Amelia Island. When coupled with industrial expansion in the area and the ability to do so within the context of the "Agreement" and "Amendment" with FPL, the already quantifiable benefits of the existing project has piqued the interest of others to contemplate partnering with a new CHP-based project. Given that FPUC would again be the recipient of any power generated by such project, FPUC has been actively involved in the initial development and engineering of a new project located on Amelia Island. Significant efforts have continued to develop this CHP which, similar to Eight Flags, will be located on Amelia Island and will allow FPUC to provide additional reliability and resilience to its electricity supply for its customers on Amelia Island. This second CHP will provide competitively priced electricity for FPUC's customers while providing high pressure steam and hot water to a local industrial customer. Preliminary engineering, financial modeling, operating agreements and Florida Department of Environmental Protection permitting have been completed for this CHP unit. FPUC anticipates that work will continue on this project with the projected in-service date of second quarter of 2022.

Q. Can you provide additional information on the PV and battery projects you referenced above?

A. Yes. FPUC has completed the analysis related to smaller PV systems within the FPUC electric service territory. Based on the results from the analysis, the economic feasibility of smaller PV installations has been difficult to achieve due to many different factors. At this time, FPUC is investigating opportunities involving larger PV installations which have proved to be more economically feasible. Not only will this increase the renewable energy available to FPUC, the cost is expected to complement the overall purchased power portfolio which will provide additional benefits to FPUC customers. The "Agreement" and the "Amendment" have provisions that allow for the development of PV installations by FPUC and provides for the possibility of a partnership between the parties that would allow for the development of a PV project.

Additionally, exploration into the inclusion of battery storage capacity in conjunction with the PV installation is being considered. These projects have been difficult to justify economically at this point but are still under consideration by FPUC. Nonetheless, the potential benefits of the PV and battery projects under consideration will be continued.

Q. Does this include your testimony?

A. Yes.

(Whereupon, prefiled direct testimony of Richard L. Hume was inserted.)

GULF POWER COMPANY

Before the Florida Public Service Commission
Prepared Direct Testimony
Richard L. Hume
Docket No. 20200001-EI
Date of Filing: March 2, 2020

Q. Please state your name, business address, and occupation.

A. My name is Richard Hume. My business address is 700 Universe Blvd Juno Beach, FL 33408. I am the Regulatory Issues Manager for Gulf Power Company (Gulf or the Company).

Q. Please briefly describe your educational background and business experience.

A. I graduated from the University of Florida in 1991 with a Bachelor of Science degree in Business Administration with a Finance Major and earned a Master of Business Administration degree with a Finance Concentration from the University of Florida in 1995. In 1998, I worked for NewEnergy Associates, (which became a subsidiary of Siemens Power Generation), a consulting firm that worked with Electric and Gas Utilities across the United States. During that time, I consulted in the area of financial forecasting budgeting as well as cost of service and rate forecasting. In 2007, I joined Oglethorpe Power and after a year was promoted to the position of Director of Financial Forecasting. In that position I was primarily responsible for the long range financial forecast and resource plan. In 2012, I joined Florida Power and Light managing a data analytics team. In that position part of what my team was responsible for was customer rate and bill impact analysis and worked in partnership with the Regulatory Affairs team. In 2019, I joined Gulf Power as the Regulatory Issues Manager where my current responsibilities include oversight of the Company's fuel and purchase power cost recovery clause, calculation of cost recovery factors and the related regulatory filing function of Gulf Power Company.

Q. What is the purpose of your testimony in this docket?

A. The purpose of my testimony is to present the final true-up amounts for the period January 2019 through December 2019 for both the Fuel and Purchased Power Cost Recovery Clause and the Capacity Cost Recovery Clause. I will summarize Gulf Power Company's fuel expenses, net power transaction expense, purchased power capacity costs, and certify that these expenses were properly incurred during the period January 2019 through December 2019. Lastly, I will present the actual benchmark level for the calendar year 2020 gains on non-separated wholesale energy sales eligible for a shareholder incentive and the amount of gains or losses from hedging settlements for the period January 2019 through December 2019.

Q. Have you prepared any exhibits to which you will refer in your testimony?

A. Yes, I am sponsoring 2 exhibits. Exhibit 1 consists of 8 schedules and includes 2 schedules which relate to the fuel and purchased power cost recovery final true-up, 1 schedule that relates to Gulf's natural gas fuel hedging activities for 2019 and 5 schedules that relate to the capacity cost recovery final true-up. Exhibit 2 contains Schedules A-1 through A-9 and A-12 for the period December 2019, previously filed with the Florida Public Service Commission (FPSC or Commission).

Counsel: We ask that Mr. Hume's exhibits be marked as Exhibit No. _____(RLH-1) and ______(RLH-2).

Q. Have you verified that to the best of your knowledge and belief, the information contained in these documents is correct?

A. Yes, I have. Unless otherwise indicated, the actual data in these documents is taken from the books and records of Gulf Power Company. The books and records are kept in the regular course of business in accordance with generally accepted accounting principles and practices, and provisions of the Uniform System of Accounts as prescribed by the Commission. Based on the information in these documents and the foregoing testimony, the recoverable fuel and purchased power costs, and hedging activities are reasonable and prudent.

I. FUEL

Q. Which schedules of your exhibit relate to the calculation of the fuel and purchased power cost recovery true-up amount?

A. Schedules 1 and 2 of my Exhibit RLH-1 relate to the fuel and purchased power cost recovery true-up calculation for the period January 2019 through December 2019. These schedules compare twelve months of actual data to the actual/estimated true-up filed in last year's fuel docket which included six months of actual and six months of re-projected data. In addition, Fuel Cost Recovery Schedules A-1 through A-9 for December 2019 are incorporated herein as Exhibit RLH-2. The A-schedules compare twelve months of actual data to twelve months of projected data from a combination of the original 2019 fuel projection for the period January through June, and the 2019 estimated true-up re-projections for the period July through December.

Q. What is the final fuel and purchased power cost true-up amount related to the period January 2019 through December 2019 to be addressed through the fuel cost recovery factors in the period January 2021 through December 2021?

A. A net over-recovery amount of $8,868,596, to be returned to customers, was calculated as shown on Schedule 1 of my Exhibit RLH-1.

Q. How was this amount calculated?

A. The $8,868,596 is calculated on Schedule 1 of my Exhibit RLH-1 by taking the difference between the estimated and actual over/under-recovery amounts for the period January 2019 through December 2019. The estimated under-recovery amount was $5,178,904 as compared to the actual over-recovery amount of $3,689,691, resulting in an over-recovery of $8,868,596. The estimated true-up amount for this period was approved in FPSC Order No. PSC-2019-0484-FOF-EI, dated November 18, 2019.

Q. What are the primary factors which contributed to the final fuel and purchased power cost true-up amount?

A. Gulf Power experienced lower than estimated fuel and net power expense higher than estimated jurisdictional fuel clause revenue. These variances are discussed in more detail below and are summarized on Schedule 2 of my Exhibit RLH-1.

Fuel Clause Revenue

Q. Please explain the variance in Fuel Revenue Applicable for 2019.

A. Gulf Power's jurisdictional fuel revenue was $336,275,528 which was $6,692,460 or 2.03% above the actual / estimated.

Total Fuel and Net Power Transactions

Q. During the period January 2019 through December 2019, how did Gulf Power Company's recoverable total fuel and net power transaction expenses compare with the actual/estimated expenses?

A. Gulf's recoverable total fuel cost and net power transaction expense was $375,055,223 which is $1,229,583 or 0.33% below the estimated amount of $376,284,806. Actual fuel and net power transaction energy was 18,436,512 MWh compared to the estimated net energy of 20,047,202 MWh or 8.03% lower than the estimated amount. The lower total fuel and net power transactions expense is attributed to a lower quantity of fuel and net power transaction energy than projected for the period presented above. This information is summarized on Schedule 2 of my Exhibit RLH-1.

Total Fuel Cost of Generated Power

Q. During the period January 2019 through December 2019, how did Gulf Power Company's recoverable fuel cost of net generation compare with the actual/estimated expenses?

A. Gulf's recoverable fuel cost of system net generation was $249,555,444 or 8.67% below the estimated amount of $273,248,789. This information is summarized on Schedule 2 of my Exhibit RLH-1 and the table below provided the detail of the variance.

Fuel Variance	**MMBTU**		
	2019 Final True-Up	**2019 Actual / Estimated**	**Difference**
OIL - C.T.			
Total Dollar	$118,657	$135,743	(17,086)
Units	6,131	8,476	(2,345)
$ per Units	19.3537	16.0150	3.34
Variance Due to Consumption			(45,384)
Variance Due to Cost			28,299
Total Variance			(17,086)
GAS			
Total Dollar	$100,624,974	$102,628,377	(2,003,404)
Units	28,409,420	28,202,278	207,142
$ per Units	3.5420	3.6390	(0.10)
Variance Due to Consumption			733,688
Variance Due to Cost			(2,737,092)
Total Variance			(2,003,404)
COAL + GAS B.L. + OIL B.L.			
Total Dollar	$143,794,404	$164,371,808	(20,577,403)
Units	44,404,113	54,286,597	(9,882,484)
$ per Units	3.2383	3.0279	0.21
Variance Due to Consumption			(32,002,573)
Variance Due to Cost			11,425,169
Total Variance			(20,577,403)
Other Adjustments to Fuel Costs			
Total Variance			(1,095,452)
Total			
Total Variance Due to Consumption			(31,314,269)
Total Variance Due to Cost			8,716,376
Total Variance			(23,693,345)

Total Cost of Purchased Power

Q. During the period January 2019 through December 2019, how did Gulf Power Company's recoverable fuel cost of purchased power compare to actual/estimated cost?

A. Gulf's recoverable fuel cost of purchased power for the period was $202,815,639 or 0.11% below the estimated amount of $203,040,737. Total megawatt hours of purchased power were 7,087,293 MWh compared to the estimate of 7,116,310 MWh or 0.41% below estimates. The resulting average fuel cost of purchased power was 2.862 cents per kWh or 0.30% above the estimated amount of 2.853 cents per kWh. This information is from Schedule A-1, period-to-date, for the month of December 2019 included in my Exhibit RLH-2 and summarized on schedule 2 of Exhibit RLH-1.

Q. What are the reasons for the difference between Gulf's actual fuel cost of purchased power and the actual/estimated costs?

A. The lower total fuel cost of purchased power is primarily due to lower MWH purchased by Gulf Power through purchased power agreements than estimated.

Power Sales

Q. During the period January 2019 through December 2019 how did Gulf Power Company's recoverable fuel cost of power sold compare with the actual/estimated costs?

A. Gulf's recoverable fuel cost of power sold for the period is $79,803,568 or 21.37% lower than the estimated amount of $101,489,520. The total quantity of power sales was 3,299,829 MWh compared to Gulf's estimated sales of 4,212,573 MWh, or 21.67% below estimates. The resulting average fuel cost of power sold was 2.418 cents per kWh or 0.38% above the estimated amount of 2.409 cents per kWh. The 2019 actual information is from Schedule A-1, period-to-date, for the month of December 2019 and summarized on Schedule 2 of RLH-1.

Q. What are the reasons for the difference between Gulf's actual fuel cost of power sold and the actual/estimated costs?

A. The lower actual fuel cost of power sold is primarily due to a lower quantity of generation available for non-territorial sales after meeting Gulf's territorial load.

Gains on Non-Separated Wholesale Energy Sales Benchmark

Q. Has the benchmark level for gains on non-separated wholesale energy sales eligible for a shareholder incentive been updated for actual 2019 gains?

A. Yes, the three year rolling average gain on economy sales, based entirely on actual data for calendar years 2017 through 2019 is calculated as follows:

Year	Actual Gain
2017	1,988,936
2018	589,410
2019	159,393
Three-Year Average	$ 912,580

Q. What is the actual threshold for 2020?

A. The actual threshold for 2020 is $912,580.

II. HEDGING

Q. Did Gulf's fuel hedging activity during 2019 follow Gulf Power's Risk Management Plan for Fuel Procurement?

A. Yes. As part of the Stipulation and Settlement Agreement, in Docket No. 20160186-EI, Gulf agreed to continue its existing moratorium for new natural gas financial hedges until January 1, 2021. Although Gulf did not enter into any new financial hedge contracts in 2019, hedges that settled in 2019 were entered into prior to the current moratorium on natural gas financial hedges and complied with previously approved Risk Management Plans.

Q. For the period in question, what volume of natural gas was hedged using a fixed price contract or financial instrument?

A. Gulf Power hedged 5,560,000 MMBtu of natural gas based upon plant Smith 3 and the Central Alabama PPA combined Cycle unit projected burns in 2019 using financial instruments. This represents 9% of Gulf's 63,244,546 MMBtu of actual gas burn for these resources during the period. The total amount of natural gas burn by month for these resources is reported on Schedule 3 of Exhibit RLH-1.

Q. What types of hedging instruments were used by Gulf Power Company, and what type and volume of fuel was hedged by each type of instrument?

A. Natural gas was hedged using financial swap contracts that were entered into prior to the current moratorium to fix the price of natural gas to a certain price. These swaps settled against the NYMEX Last Day Final Settlement price.

Q. What was the actual total cost (e.g., fees, commissions, option premiums, future gains and losses, swap settlements) associated with each type of hedging instrument for the period January 2019 through December 2019?

A. No fees, commissions, or premiums were paid by Gulf on the financial hedge transactions during this period. Gulf's 2019 hedging program activities for the period January through December 2019 resulted in a net hedge settlement cost of $7,178,070 as shown on line 2 of the December 2019 Schedule A-1, period-to-date of my Exhibit RLH-2.

III. PURCHASED POWER CAPACITY

Q. Mr. Hume, you stated earlier that you are responsible for the purchased power capacity cost recovery true-up calculation. Which schedules of your exhibit relate to the calculation of this amount?

A. Schedules 4, CCA-1, CCA-2, CCA-3, and CCA-4 of Exhibit RLH-1 relate to the purchased power capacity cost recovery true-up calculation for the period January 2019 through December 2019. Schedules CCA-1 and Schedule 4 summarize the calculation of the final true-up amount. Schedules CCA-2 through CCA-4 provides the monthly calculation of the actual over/under-recovery of purchased power capacity costs, monthly calculation of the interest provision and additional details related to purchased power capacity contracts which also appear on Lines 1 and 2 of Schedule CCA-2. In addition, Schedule A-12 of my Exhibit RLH-2 contains purchased power capacity cost information for the period January 2019 through December 2019.

Q. What is the final purchased power capacity cost true-up amount related to the period of January 2019 through December 2019 to be addressed in the period January 2021 through December 2021?

A. An over-recovery amount of $452,844 should be returned to customers through 2021 purchased power capacity clause rates as shown on Schedule CCA-1 of Exhibit RLH-1.

Q. How was this amount calculated?

A. The $452,844 was calculated by taking the difference between the estimated January 2019 through December 2019 under-recovery of $622,746 and the actual under-recovery of $169,902. This true up amount is also the sum of lines 11, 12, and 15 under column 1 of Schedule 4 of Exhibit RLH-1. The estimated true-up amount for this period was approved in FPSC Order No. PSC-2019-0484-FOF-EI dated November 18, 2019.

Additional details supporting the approved estimated true-up amount are included on Schedules CCE-1A and CCE-1B filed July 26, 2019.

Q. During the period January 2019 through December 2019, how did Gulf's actual total purchased power capacity costs and jurisdictional capacity clause revenue compare with the actual/estimated amounts?

A. The actual total capacity payments for the period January 2019 through December 2019, as shown on line 5 of Schedule 4 contained in my Exhibit RLH-1, was $77,628,374. Gulf's total estimated net purchased power capacity cost for the same period was $77,449,608, as indicated on line 5 of Schedule CCE-1B the Exhibit CSB-3 filed July 26, 2019 in Docket No. 20190001-EI. The difference between the actual net capacity cost and the estimated net capacity cost for the recovery period is $178,766 or 0.23% more than the estimated amount. Jurisdictional capacity clause revenue for the period January 2019 through December 2019, as shown on line 10 of Schedule 4, was $75,254,563, or $604,571 higher than the estimate of

$74,649,992. Jurisdictional capacity clause revenue and expense variances were less than one percent for the period.

Q. Mr. Hume, does this complete your testimony?
A. Yes.

AFFIDAVIT

STATE OF FLORIDA)
)
COUNTY OF ESCAMBIA)

Docket No. 20200001-EI

Before me, the undersigned authority, personally appeared Richard L. Hume, who being first duly sworn, deposes and says that he is the Regulatory Issues Manager of Gulf Power Company, a Florida corporation, that the foregoing is true and correct to the best of his knowledge and belief. He is personally known to me.

Richard L. Hume
Richard L. Hume
Regulatory Issues Manager

Sworn to and subscribed before me by means of ✓ physical presence or ____ online notarization this 2nd day of March, 2020.

Melissa Darnes
Notary Public, State of Florida at Large

NOTARY PUBLIC STATE OF FLORIDA
MELISSA A DARNES
Commission # GG 366942
Expires December 17, 2023
Bonded Thru Budget Notary Services

Gulf Power

FUEL AND PURCHASED POWER CAPACITY

Witness: Richard L. Hume

Exhibit Index

Exhibit	Schedule	Description	Page
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BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

GULF POWER COMPANY

TESTIMONY OF RICH L. HUME

DOCKET NO. 20200001-EI

JULY 27, 2020

Q. Please state your name and address.

A. My name is Richard Hume. My business address is Gulf Power Company, 700 Universe Boulevard, Juno Beach, FL 33408.

Q. By whom are you employed and in what capacity?

A. I am employed by Gulf Power Company ("Gulf" or "Gulf Power") as Manager of Regulatory Issues, in the Regulatory & State Governmental Affairs Department.

Q. Have you previously testified in this docket?

A. Yes, I have.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present for Commission review and approval the calculation of the actual/estimated true-up amounts for the Fuel Cost Recovery ("FCR") Clause and the Capacity Cost Recovery ("CCR") Clause for the period January 2020 through December 2020.

Q. Have you prepared or caused to be prepared under your direction, supervision or control any exhibits with your testimony?

A. Yes, various schedules are included in Exhibit RLH-3 and Exhibit RLH-4. Exhibit RLH-3 contains the FCR schedules and Exhibit RLH-4 contains the CCR schedules.

Q. What is the source of the actual data that you present by way of testimony or exhibits in this proceeding?

A. Unless otherwise indicated, the actual data are taken from the books and records of Gulf Power Company. The books and records are kept in the regular course of the Company's business in accordance with generally accepted accounting principles and practices, as well as the provisions of the Uniform System of Accounts as prescribed by this Commission.

Q. Please describe the data that Gulf has used as a comparison when calculating the FCR and CCR actual/estimated true-up amounts presented in your testimony.

A. The FCR true-up calculation compares actual/estimated data consisting of actuals for January 2020 through June 2020 and revised estimates for July 2020 through December 2020 to the data reflected in Gulf's 2020 Mid-Course Correction for the period January 2020 through December 2020 filed on April 2, 2020. However, the CCR true-up calculation compares actual/estimated data consisting of actuals for January 2020 through June 2020 and revised estimates for July 2020 through December 2020 to the data reflected in Gulf's original projections for the period January 2020 through December 2020 filed on September 3, 2019.

Q. Please explain the calculation of the interest provision that is applicable to the FCR and CCR true-up amounts.

A. The calculation of the interest provision follows the methodology used in calculating the interest provision for all cost recovery clauses, as previously approved by this Commission. The interest provision is the result of multiplying the monthly average true-up amount for the twelve-month period by the monthly average interest rate. The average interest rate for the months reflecting actual data is developed using the AA financial 30-day rates as published on the Federal Reserve website on the first business day of the current month and the subsequent month divided by two. The average interest rate for the estimated months is the actual rate published on the first business day in July 2020, which reflects the interest rate from the last business day in June 2020.

FUEL COST RECOVERY CLAUSE

Q. What has Gulf calculated as the fuel cost recovery true-up factor to be applied in the period January 2020 through December 2020?

A. The fuel cost recovery true-up factor for this period is 0.0102 cents per kWh. As shown on Schedule E-1A, this calculation includes an estimated under-recovery for the January through December 2020 period of $9,968,285 and the 2019 final true-up over-recovery position of $8,868,596 (see Schedule 1 of Exhibit RLH-1 filed in this docket on March 2, 2020) resulting in an under-recovery of $1,099,690 for the period.

The 2020 estimated under-recovery of $9,968,285 includes a mid-course correction refund credit calculated on an estimated refund of $51.3 million. (see Schedule E-1A Attachment 1 page 1 of the Petition of Gulf Power Company for Mid-Course Correction filed on April 2, 2020). The 2020 year-end under-recovery estimate of $1,099,690 will be incorporated into Gulf's proposed 2021 fuel cost recovery factors.

Q. Have you provided a schedule showing the calculation of the FCR 2020 actual/estimated true-up by month?

A. Yes. Exhibit RLH-3, schedule E-1B shows the calculation of the FCR actual/estimated true-up by month for the period January 2020 through December 2020.

Q. Please explain the calculation of the FCR end-of-period net true-up and actual/estimated true-up amounts you are requesting this Commission to approve.

A. Exhibit RLH-3, schedule E-1B shows the calculation of the FCR end-of-period net true-up and actual/estimated true-up amounts. The 2020 end-of-period net true-up amount to be carried forward to the 2021 FCR factors is an under-recovery of $9,968,285 (schedule E1-B, line 9, column 15). This amount includes the under-recovery amount for the period of $10,006,166 reduced by interest due to customers of $37,882 (Exhibit RLH-3, schedule E-1B, lines 6 plus 7, column 15).

Q. Were these calculations made in accordance with the procedures previously approved in predecessors to this Docket?

A. Yes.

Q. Have you provided a schedule showing the variances between the actual/estimated amounts and the projections for 2019?

A. Yes. Exhibit RLH-3, schedule E-1B-1 provides a variance calculation that compares the 2020 actual/estimated period data by component to the same components from the 2020 mid-course correction filed on April 2, 2020.

Q. Please summarize the variance schedule E-1B-1 of Exhibit RLH-3.

A. Gulf's mid-course correction projected jurisdictional Total Fuel and Net Power Transaction costs to be $306.2 million for 2020 (Exhibit RLH-3, schedule E-1B-1, line 13, column 4). The 2020 actual/estimated jurisdictional Total Fuel and Net Power Transactions are now estimated to be $310.3 million (Exhibit RLH-3, schedule E-1B-1, line 13, column 3). The net impact to total jurisdictional fuel costs is $4.1M or 1.32% increase in fuel cost from the mid-course correction (Exhibit RLH-3, Schedule E1B1, line 21).

Q. Please explain the variances in jurisdictional total fuel costs and net power transactions.

A. The summary below shows the primary drivers for the $4.1 million variance in jurisdictional total fuel costs.

Description	Variance (millions)
Fuel Costs of System Net Generated	$ (20.8)
Other Generation Power	$ (1.1)
Total Cost of Purchased Power	$ (0.7)
Gain on Power Sales	$ 26.7
Total	**$ 4.1**

<u>Fuel Cost of System Net Generation: $20.8 million decrease (Exhibit RLH-3, schedule E-1B-1, line 1 column 5):</u>

The primary drivers for the decrease of System Net Generation are lower coal consumption and lower prices for gas. The table below outlines the variances in more detail and is also shown on schedule E3.

Fuel Variance by Major Fuel Type	2020 Actual Estimated	2020 Midcourse Correction	Variance
OIL - C.T.			
Total Dollar	$56,283	$15,523	$ 40,760
MMBTU	3,607	1,005	$ 2,602
$ per MMBTU	15.60	15.45	$ 0.15
		Variance Due to Consumption	$ 40,591
		Variance Due to Cost	$ 169
GAS			
Total Dollar	$115,892,747	$136,160,615	$ (20,267,868)
MMBTU	53,102,470	52,904,939	$ 197,531
$ per MMBTU	2.18	2.57	$ (0.39)
		Variance Due to Consumption	$ 430,618
		Variance Due to Cost	$ (20,698,486)
COAL + GAS B.L. + OIL B.L.			
Total Dollar	$96,188,953	$96,870,135	$ (681,182)
MMBTU	30,846,853	33,944,999	$ (3,098,146)
$ per MMBTU	3.12	2.85	$ 0.27
		Variance Due to Consumption	$ (9,666,216)
		Variance Due to Cost	$ 8,985,034
Other Adjustments to Fuel Costs			
Total Variance	894,494	860,835	$ 33,659
		Total Variance Due to Consumption	$ (9,195,007)
		Total Variance Due to Cost	$ (11,679,624)
		Total Variance	$ (20,874,632)

<u>Other generated power: $1.1 million decrease (Exhibit RLH-3, schedule E-1B-1, lines 1a,1b,2 and 3, column 5):</u>

Other costs of generated power variances are those related to hedging costs, other generation and miscellaneous adjustments to fuel costs.

<u>Total Cost of Purchased Power: $0.7 million decrease (Exhibit RLH-3, schedule E-1B-1, line 7, column 5):</u>

The variance for the Cost of Purchased Power is primarily attributed to a decrease in cost of other economy purchases offset by an increase in payments to qualified facilities. Additionally, as a result of lower cost energy available in the Southern Company Power Pool, Gulf is estimating an increase of 184,269 or 2.5% in MWH purchases. The actual/estimated costs of purchased power (cents / kWh) is 2.82%

lower than originally projected for those purchases. The actual/estimated cost of purchased power is 2.3964 cents per kWh which is 0.0695 lower than the original projected price per kWh of 2.4659 which is $703,267 or 0.39% lower than original projected.

Total Gains on Power Sales: $26.7 million increase (Exhibit RLH-3, schedule E-1B-1, line 12, column 5): The variance for Gains on Power sales is primarily attributed to 1,199,460 MWh or 20.44% lower than projected power sales. Gulf is also estimating a lower than projected reimbursement for these sales of 0.0811 cents per kWh or 4.25%. The lower sales and lower price per kWh results in $26.7 million or 23.82% lower sales credit to Gulf's customers.

CAPACITY COST RECOVERY CLAUSE

Q. Have you provided a schedule showing the calculation of the CCR 2020 actual/estimated true-up by month?

A. Yes. Exhibit RLH-4, schedule CCE-1A provides the calculation of the CCR actual/estimated true-up by month for the period January 2020 through December 2020.

Q. What has Gulf calculated as the purchased power capacity factor true-up to be applied in the period January 2020 through December 2020?

A. The true-up for this period is 0.0209 cents per kWh, as shown on Schedule CCE-1A. This calculation includes an estimated under-recovery of $2,700,587 for January 2020 through December 2020. It also includes a final over-recovery of $452,844 for the period January 2019 through December 2019 (see Schedule

CCA-1 of Exhibit RLH-1 filed in this docket on March 2, 2020). The resulting total under-recovery of $2,247,743 will be incorporated into Gulf Power's proposed 2021 purchased power capacity cost recovery factors.

Q. Please explain the calculation of the CCR 2019 actual/estimated true-up and the end-of-period net true-up amounts you are requesting this Commission to approve.

A. Exhibit RLH-4, CCE-1B shows the actual/estimated capacity costs and applicable revenues (January 2020 through June 2020 reflects actual data, while the data for July 2020 through December 2020 is based on updated estimates) compared to the original projection filing for the January 2020 through December 2020 period. The $2,247,743 under-recovery is due to lower than projected retail sales. The total jurisdictional capacity payments are projected to be $502,053 or 0.6% lower than Gulf's original projection filing.

Description	2020 Actual Estimated	2020 Projection	Variance
Total Jurisdictional Capacity Payments	$82,984,719	$83,486,772	($502,053)

Q. Is this true-up calculation made in accordance with the procedures previously approved in predecessors to this docket?

A. Yes.

Q. Does this conclude your testimony?

A. Yes, it does.

AFFIDAVIT

STATE OF FLORIDA)
)
COUNTY OF ESCAMBIA)

Docket No. 20200001-EI

Before me, the undersigned authority, personally appeared Richard L. Hume, who being first duly sworn, deposes and says that he is the Regulatory Issues Manager of Gulf Power Company, a Florida corporation, that the foregoing is true and correct to the best of his knowledge and belief. He is personally known to me.

Richard L. Hume
Regulatory Issues Manager

Sworn to and subscribed before me by means of ✓ physical presence or ____ online notarization this 27th day of July, 2020.

Melissa Darnes
Notary Public, State of Florida at Large

NOTARY PUBLIC STATE OF FLORIDA
MELISSA A DARNES
Commission # GG 366942
Expires December 17, 2023
Bonded Thru Budget Notary Services

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

GULF POWER COMPANY

TESTIMONY OF RICHRD L. HUME

DOCKET NO. 20200001-EI

SEPTEMBER 3, 2020

Q. Please state your name, business address and occupation.

A. My name is Richard Hume. My business address is Gulf Power Company ("Gulf"), One Energy Place Pensacola, FL 32520.

Q. Have you previously filed testimony in this docket?

A. Yes, I have.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to discuss the projection of fuel expenses, net power transaction expenses, and purchased power capacity costs for the period January 2021 through December 2021 for which Gulf seeks recovery through the Fuel Cost Recovery ("FCR") Clause. I will also present the calculation of Gulf's Capacity Cost Recovery ("CCR") factors for the period January 2021 through December 2021.

Q. Have you prepared any exhibits that contain information to which you will refer in your testimony?

A. Yes, I have. They are as follows:

Exhibit Number	Summary
Exhibit RLH-5	23 schedules related to Fuel and Capacity Calculations

Exhibit Number	Summary
Exhibit RLH-6	Gulf's Hedging Information Report filed with the Commission Clerk on April 3, 2020, and assigned Document Numbers DN 01746-2020 (redacted) and 01752-2020 (confidential information). This exhibit details Gulf's natural gas hedging transactions for August 2019 through December 2019 in compliance with Order No. PSC-08-0316-PAA-EI.
Exhibit RLH-7	Gulf's Hedging Information Report filed with the Commission Clerk on August 10, 2020, and assigned Document Numbers DN 0431-2020 (redacted) and DN 04308-2020 (confidential information). This exhibit details Gulf's natural gas hedging transactions for January 2020 through March 2020 in compliance with Order No. PSC-08-0316-PAA-EI.
Exhibit RLH-8	Calculation of the stratified separation factors.

Q. Have you verified that to the best of your knowledge and belief, the information contained in these documents is correct?

A. Yes, I have.

FUEL COST RECOVERY CLAUSE

Q. Please explain the calculation of the fuel and purchased power expense true-up amount included in the annual fuel factor for the period January 2021 through December 2021.

A. The 2021 FCR factors includes an adjustment to the total net true-up, for the Generating Performance Incentive Factor ("GPIF"). As shown on Schedule E-1A of Exhibit RLH-5, the total true-up amount is a $1,099,690 under-recovery for the period January 2020 through December 2020. The estimated under-recovery includes six months of actual data and six months of estimated data as reflected on Schedule E-1B of Exhibit RLH-5.

The GPIF result shown on Line 26 of Schedule E-1 is an increase of 0.0006 cents per kWh to the annual fuel factor. This amount represents an increase in the amount of $62,232 as shown in Exhibit JAV-1 of Witness Van Norman's testimony filed on March 16, 2020.

Q. What is the appropriate revenue tax factor to be applied in calculating the annual fuel factor?

A. A revenue tax factor of 1.00072 has been applied to all jurisdictional fuel costs, as shown on Line 24 of Schedule E-1.

Q. What is the annual projected fuel factor for the period January 2021 through December 2021?

A. Gulf has proposed an annual fuel factor of 3.053 cents per kWh. This factor is based on projected fuel and purchased power energy expenses and projected kWh sales for January 2021 through December 2021 and includes the true-up and GPIF amounts identified above.

Q. How were the line loss multipliers used on Schedule E-1E calculated?

A. The line loss multipliers were calculated in accordance with procedures approved in prior filings and were based on Gulf's latest MWh Load Flow Allocators.

Q. What fuel factor does Gulf propose for its largest group of customers (Group A), those on Rate Schedules RS, GS, GSD, and OS-III?

A. Gulf proposes a standard fuel factor, adjusted for line losses, of 3.070 cents per kWh for Group A. Fuel factors for Groups A, B, C, and D are shown on Schedule E-1E. These factors have all been adjusted for line losses.

Q. How were the time-of-use fuel factors calculated?

A. The time-of-use fuel factors were calculated based on seasonal on and off-peak projected loads for the period January 2021 through December 2021 and include the GPIF and true-up amount. These time-of-use fuel factors as shown on Schedule E-1E have all been adjusted for line losses.

Q. How does the proposed fuel factor for Rate Schedule RS compare with the factor applicable to December 2020, and how would the change affect the cost of 1,000 kWh on Gulf's residential rate RS?

A. The current 2020 fuel factor for Rate Schedule RS applicable through December 2020 is 3.262 cents per kWh compared with the proposed factor of 3.070 cents per kWh. For a residential customer who is billed for 1,000 kWh in January 2021, the fuel portion of the bill would decrease from $32.62 to $30.70 or a 5.9% decrease.

Q. Has Gulf updated its estimates of the as-available avoided energy costs to be shown on COG1 as required by Order No. 13247 issued May 1, 1984, in Docket No. 830377-EI and Order No. 19548 issued June 21, 1988, in Docket No. 880001-EI?

A. Yes. A tabulation of these costs is set forth in Schedule E-11 of my exhibit. These costs represent the estimated averages for the period January 2021 through December 2021. In addition, pursuant to Commission Order No. PSC-16-0119-TRF-EG in Docket No. 150248-EG, Gulf has calculated what the bill credit would be if it launched the Community Solar Pilot Program described in that Order. The bill credit would be $1.68 per month based on the 2021 projected solar-weighted average annual avoided energy cost is 2.7 cents per kWh for the period January 2021 and December 2021.

Q. What amount have you calculated to be the appropriate benchmark level for calendar year 2020 gains on non-separated wholesale energy sales eligible for a shareholder incentive?

A. In accordance with Order No. PSC-00-1744-PAA-EI, an estimated three-year average benchmark level has been calculated as follows:

2018 actual gains	589,410
2019 actual gains	159,393
2020 estimated gains	74,883
Three-Year Average	$274,562

This amount represents the minimum projected threshold for 2021 that must be achieved before shareholders may receive any incentive.

FUEL PROCUREMENT

Q. Please describe Gulf's fuel procurement program for the 2021 projected period?

A. Gulf's coal requirements are purchased in the market through the Request for Proposal (RFP) process that has been used for many years. Natural gas supply will be purchased from multiple suppliers using a combination of firm quantity agreements with market-based pricing for baseload needs and daily spot market purchases. Natural gas transportation will be secured using a combination of firm and spot transportation agreements.

Q. What actions does Gulf take to procure natural gas supply and natural gas transportation for its units at competitive prices for both long-term and short-term deliveries?

A. Gulf procures natural gas using both long and short-term agreements for gas supply at market-based prices. Gulf secures gas transportation using a combination of long-term agreements for firm pipeline capacity and released capacity, delivered natural gas, and interruptible transportation for shorter term needs.

HEDGING

Q. Has anything changed with regard to the status of Gulf's hedging program since filing testimony on July 27, 2020, in this docket?

A. There has been no change in the status of Gulf's hedging program. Gulf's fuel hedging program was terminated pursuant to the Stipulation and Settlement Agreement approved by this Commission in Order No. PSC-17-0178-S-EI. Gulf's hedge positions that were put in place prior to terminating all hedging activities ended as of March 2020. Accordingly, actual hedging settlement data is included in my Exhibit RLH-6 as previously filed with this Commission on August 10, 2020. Gulf has no further hedging activity to report past March 2020.

Q. What were the results of Gulf's natural gas price hedging program for the period August 2019 through March 2020?

A. Gulf had financial hedges in place during the August 2019 through March 2020 period to hedge the price of natural gas. These financial hedges were effective in delivering greater price certainty for a portion of Gulf's natural gas requirements during that time period. Between August 2019 and July 2020, Gulf recorded hedging settlement costs of $5,154,160. Pursuant to Order No. PSC-08-0316-PAA-EI, Gulf filed Hedging Information Reports with the Commission on April 3, 2020, and August 10, 2020, detailing its natural gas hedging transactions for August 2019 through March 2020. I am sponsoring these reports as Exhibits RLH-6 and RLH-7 to my testimony in this docket.

CAPACITY COST RECOVERY CLAUSE

Q. You stated earlier that you are responsible for the calculation of the Capacity Cost Recovery factors. Which of your exhibits relate to the calculation of these factors?

A. Schedule CCE-1, including CCE-1A and CCE-1B, Schedule CCE-2, and Schedule CCE-4 of my Exhibit RLH-5 relate to the calculation of the CCR recovery factors for the period January 2021 through December 2021.

Q. Please describe Schedule CCE-1 of your exhibit.

A. Schedule CCE-1 provides the calculation of stratified jurisdictional capacity costs to be recovered through the CCR. The schedule provides Gulf's total projected net capacity expense, which includes a credit for transmission revenue. The total net projected capacity costs are applied to a stratified jurisdictional factor and added to the total true-up which is then adjusted for revenue taxes to determine the amount to be recovered in the period through CCR recovery factors.

The total recoverable capacity payments for the period are $85,862,394. This amount is captured in the Schedule CCE-1, line 20. Schedule CCE-4 shows the projected cost associated with the Southern Intercompany Interchange capacity, if applicable, and any long-term purchased power contracts that are included for capacity cost recovery and lists their associated capacity amounts in megawatts. Also included in Gulf's 2021 projection of capacity cost is revenue produced by a market-based agreement between the Southern electric system operating companies and South Carolina PSA (Public Service Authority). The total capacity cost of $85,691,528 is shown on Schedule CCE-4, line 11.

Gulf has included an estimate of transmission revenues associated with off-system economy sales in the amount of $84,000 in its capacity cost recovery projection. This amount is captured on Schedule CCE-1, line 6 of my Exhibit RLH-5.

Q. What jurisdictional factor was used to calculate projected recoverable capacity costs for the period January 2021 through December 2021?

A. The calculations of the separation factors are provided in Exhibit RLH-8. Gulf has separated the production-related capacity costs based on stratified separation factors that better reflect the types of generation required to serve load under stratified wholesale power sales contracts. The use of stratified separation factors thus results in a more accurate separation of capacity costs between the retail and wholesale jurisdictions.

Gulf has one stratified wholesale power sales contract effective as of January 1, 2020, with Florida Public Utility. The separation factors for the intermediate and peaking strata associated with this contract was calculated in a manner consistent with the method used by Florida Power & Light Company and Duke Energy Florida using Gulf's 2018 Cost of Service Load Research Study filed with this Commission in accordance with Rule 25-6.0437, F.A.C.

Q. What is the appropriate revenue tax factor to be applied in calculating the total recoverable capacity payments?

A. A revenue tax factor of 1.00072 has been applied to all jurisdictional capacity costs, as shown on Line 19 of Schedule CCE-1.

Q. What methodology was used to allocate the capacity payments by rate class?

A. As required by Commission Order No. 25773 in Docket No. 910794-EQ, the revenue requirements have been allocated using the cost of service methodology approved by the Commission in Order No. PSC-17-0178-S-EI in consolidated Docket Nos. 160186-EI and 160170-EI. This allocation is consistent with the treatment accorded to production plant in the cost of service study approved by the Commission in Gulf's most recent base rate proceeding. For purposes of the CCR Clause, Gulf has allocated the net capacity costs by rate class within the retail jurisdiction based on the 12-Monthly Coincident Peak (MCP) and 1/13th method described below.

Q. How were the rate class allocation factors used in the CCR Clause calculated?

A. The rate class demand allocation factors used in the CCR Clause has been calculated using the 2018 Cost of Service Load Research Study results filed with the Commission in accordance with Rule 25-6.0437, F.A.C. and adjusted for losses. The rate class energy allocation factors were calculated based on projected kWh sales for the period and adjusted for losses. The calculations of the allocation factors are shown in columns A through I on page 1 of schedule CCE-2.

Q. Please describe the calculation of the CCR recovery factors by rate class used to recover capacity costs.

A. The CCR recovery factors by rate class are calculated by dividing the revenue requirement assigned to each rate class by the classes' billing determinants. The revenue requirements are assigned to each rate class as shown in columns A through D on page 2 of Schedule CCE-2 based on the 12-MCP and 1/13th method, whereby 12/13ths of the jurisdictional capacity costs to be recovered is allocated by rate class based on the demand allocator and 1/13th is allocated based on the energy allocator.

Gulf has calculated the CCR factor for the LP/LPT rate classes based on kilowatt (kW) demand rather than kilowatt hour (kWh) in accordance with Order No. PSC-13-0670-S-EI issued December 9, 2013, in Docket No. 130140-EI. The total revenue requirement assigned to rate class LP/LPT shown in column E is divided by the sum of the projected billing demands (kW) for the twelve-month period to calculate the CCR recovery factor. This factor would be applied to each LP/LPT customer's billing demand (kW) to calculate the amount to be billed each month.

For all other rate classes, the total revenue requirement assigned to each rate class shown in column E is divided by that class's projected kWh sales for the twelve-month period to calculate the CCR recovery factor. This factor would be applied to each customer's total kWh sales to calculate the amount to be billed each month.

Q. What is the amount related to capacity costs recovered through this factor that will be included on a residential customer's bill for 1,000 kWh?

A. The capacity costs recovered through the clause for a residential customer who is billed for 1,000 kWh the capacity charge would increase from $8.78 to $9.15 or 4.2%.

Q. Have there been any new purchased power agreements entered into by Gulf that impact the total recoverable capacity payments for the period?

A. No.

Q. When does Gulf propose to collect these new FCR charges and CCR charges?

A. Gulf proposes that the FCR factors and CCR factors for the period January 2021 through December 2021 become effective starting with the first meter readings made on or after January 1, 2021. These factors should remain in effect until modified by the Commission.

Q. Mr. Hume, does this conclude your testimony?

A. Yes.

AFFIDAVIT

STATE OF FLORIDA)
) Docket No. 20200001-EI
COUNTY OF ESCAMBIA)

Before me, the undersigned authority, personally appeared Richard L. Hume, who being first duly sworn, deposes and says that he is the Regulatory Issues Manager of Gulf Power Company, a Florida corporation, that the foregoing is true and correct to the best of his knowledge and belief. He is personally known to me.

Richard L. Hume

Richard L. Hume
Regulatory Issues Manager

Sworn to and subscribed before me by means of ✓ physical presence or ____ online notarization this 2nd day of September, 2020.

Melissa Darnes

Notary Public, State of Florida at Large

NOTARY PUBLIC STATE OF FLORIDA
MELISSA A DARNES
Commission # GG 366942
Expires December 17, 2023
Bonded Thru Budget Notary Services

(Whereupon, prefiled direct testimony of Jarvis Van Norman adopted by Charles Rote and the prefiled direct testimony of Charles Rote was inserted.)

GULF POWER COMPANY

Before the Florida Public Service Commission
Prepared Direct Testimony
J. A. Van Norman
Docket No. 20200001-EI
Date of Filing: March 16, 2020

Q. Please state your name, business address and occupation.

A. My name is Jarvis A. Van Norman. My business address is One Energy Place, Pensacola, Florida 32520-0335. My current job position is Budget Supervisor of Power Generation for Gulf Power Company.

Q. Please briefly describe your educational background and business experience.

A. I received my Bachelor of Science degree in Business Administration from the University of Southern Mississippi in 1987. I joined Gulf Power in 1985 as a coop student in the Accounting organization. After graduating in December 1987, I joined Gulf Power in 1988 and worked three years in Customer Accounting. I transferred throughout Gulf Power's Accounting organization through the years with increased responsibilities. In 2006, I transferred to Southern Company Services where I was the Admin Lead on Gulf Power's scrubber project at Plant Crist. In 2010, I transferred back to Gulf Power in Property Accounting where I performed Gulf Power's Depreciation Study. In 2014, I was promoted to Budget Supervisor of External Affairs and Corporate Services until 2018 when I was promoted to Budget Supervisor of Power Generation. My current responsibilities include oversight of Power Generation's O&M and capital budgets and preparing all Generating

Performance Incentive Factor (GPIF) filings as well as other generating plant reliability and heat rate performance reporting for Gulf Power Company.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present GPIF results for Gulf Power Company for the period of January 1, 2019, through December 31, 2019.

Q. Have you prepared an exhibit that contains information to which you will refer in your testimony?

A. Yes. I have prepared an exhibit consisting of five schedules.

Counsel: We ask that Mr. Van Norman's Exhibit consisting of five schedules be marked as Exhibit No. _______ (JAV-1).

Q. Is there any information that has been supplied to the Commission pertaining to this GPIF period that requires amendment?

A. Yes. Some corrections have been made to the actual unit performance data, which was submitted monthly to the Commission during this time period. These corrections are based on discoveries made during the final data review to ensure the accuracy of the information reported in this filing. The actual unit performance data tables on pages 13 through 22 of Schedule 5 of exhibit JAV-1 incorporate these changes. The data contained in these tables is the data upon which the GPIF calculations were made.

Q. Please review the Company's equivalent availability results for the period.

A. Actual equivalent availability and adjusted actual equivalent availability figures for each of the Company's GPIF units are shown on page 12 of Schedule 5. Pages 3 through 7 of Schedule 2 contain the calculations for the adjusted actual equivalent availabilities.

A calculation of GPIF availability points based on these availabilities and the targets established by FPSC Order No. PSC-2018-0610-FOF-EI is on page 8 of Schedule 2. The results are: Scherer 3, 10.00 points; Crist 7, 0.00 points; Daniel 1, 0.00 points; Daniel 2, 0.00 points; and Smith 3, 10.00 points.

Q. What were the heat rate results for the period?

A. The detailed calculations of the actual average net operating heat rates for the Company's GPIF units are on pages 2 through 6 of Schedule 3. As was done for the prior GPIF periods, and as indicated on pages 7 through 11 of Schedule 3, the target equations were used to adjust actual results to the target basis. These equations, submitted in August 2018, are shown on page 13 of Schedule 3. As calculated on page 14 of Schedule 3, the adjusted actual average net operating heat rates correspond to the following GPIF unit heat rate points:

Scherer 3, -0.45 points; Crist 7, 0.00 points; Daniel 1, 0.00 points; Daniel 2, 8.76 points, and Smith 3, 0.00 points.

Q. What number of Company points was achieved during the period, and what reward or penalty is indicated by these points according to the GPIF procedure?

A. Using the unit equivalent availability and heat rate points previously mentioned, along with the appropriate weighting factors, the number of Company points achieved was 0.1 as indicated on page 2 of Schedule 4. This calculated to a reward in the amount of $62,232.

Q. Please summarize your testimony.

A. In view of the adjusted actual equivalent availabilities, as shown on page 8 of Schedule 2, and the adjusted actual average net operating heat rates achieved, as shown on page 14 of Schedule 3, evidencing the Company's performance for the period, Gulf calculates a reward in the amount of $62,232 as provided by the GPIF methodology.

Q. Does this conclude your testimony?

A. Yes.

AFFIDAVIT

STATE OF FLORIDA)
)
COUNTY OF ESCAMBIA)

Docket No. 20200001-EI

Before me, the undersigned authority, personally appeared Jarvis Van Norman, who being first duly sworn, deposes and says that he is the Budget Supervisor of Gulf Power Company, a Florida corporation, that the foregoing is true and correct to the best of his knowledge and belief. He is personally known to me.

Jarvis Van Norman
Budget Supervisor

Sworn to and subscribed before me by means of ✓ physical presence or ____ online notarization this 16th day of March, 2020.

Notary Public, State of Florida at Large

NOTARY PUBLIC STATE OF FLORIDA
MELISSA A DARNES
Commission # GG 366942
Expires December 17, 2023
Bonded Thru Budget Notary Services

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

GULF POWER COMPANY

DIRECT TESTIMONY OF C.R. ROTE

DOCKET NO. 20200001-EI

SEPTEMBER 3, 2020

Q. Please state your name, address, and occupation.

A. My name is Charles R. Rote. My business address is 700 Universe Boulevard, Juno Beach, Florida 33408. My current job position is Business Services Director in the Power Generation Division of FPL.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to present GPIF targets for Gulf Power Company for the period of January 1, 2021 through December 31, 2021.

Q. Have you prepared an exhibit that contains information to which you will refer in your testimony?

A. Yes. I have prepared one exhibit entitled CR-1 consisting of three schedules.

Q. Was this exhibit prepared by you or under your direction and supervision?

A. Yes, it was.

Q. Which units does Gulf propose to include under the GPIF for the subject period?

A. We propose that Crist Unit 7, Daniel Units 1 and 2, Smith Unit 3, and Scherer Unit 3 be included as the Company's GPIF units. The projected net generation from these units is approximately 89% of Gulf's projected net generation for 2021.

Q. For these units, what are the target heat rates Gulf proposes to use in the GPIF for these units for the performance period January 1, 2021 through December 31, 2021?

A. I would like to refer you to page 26 of Schedule 1 of my exhibit where these targets are listed.

Q. How were these proposed target heat rates determined?

A. They were determined according to the GPIF Implementation Manual procedures for Gulf.

Q. Describe how the targets were determined for Gulf's proposed GPIF units.

A. Page 2 of Schedule 1 of my exhibit shows the target average net operating heat rate equations for the proposed GPIF units and pages 4 through 23 of Schedule 1 contain the weekly historical data used for the statistical development of these equations. Pages 24 and 25 of Schedule 1 present the calculations that provide the unit target heat rates from the target equations.

Q. Were the maximum and minimum attainable heat rates for each proposed GPIF unit indicated on page 26 of Schedule 1 of your exhibit calculated according to the appropriate GPIF Implementation Manual procedures?

A. Yes.

Q. What are the proposed target, maximum, and minimum equivalent availabilities for Gulf's units?

A. The target, maximum, and minimum equivalent availabilities are listed on page 4 of Schedule 2 of my exhibit.

Q. How were the target equivalent availabilities determined?

A. The target equivalent availabilities were determined according to the standard GPIF Implementation Manual procedures for Gulf and are presented on page 2 of Schedule 2 of my exhibit.

Q. How were the maximum and minimum attainable equivalent availabilities determined for each unit?

A. The maximum and minimum attainable equivalent availabilities, which are presented along with their respective target availabilities on page 4 of Schedule 2 of my exhibit, were determined per GPIF Implementation Manual procedures for Gulf.

Q. Mr. Rote, has Gulf completed the GPIF minimum filing requirements data package?

A. Yes, we have completed the minimum filing requirements data package. Schedule 3 of my exhibit contains this information.

Q. Mr. Rote, would you please summarize the targets that you are proposing?

A. Yes. Gulf asks that the Commission accept:

1. Crist Unit 7, Daniel Units 1 and 2, Smith Unit 3, and Scherer Unit 3 for inclusion under the GPIF for the period of January 1, 2021 through December 31, 2021.

2. The target, maximum attainable, and minimum attainable average net operating heat rates, as proposed by the Company and as shown on page 26 of Schedule 1 and on page 5 of Schedule 3 of my exhibit.

3. The target, maximum attainable and minimum attainable equivalent

availabilities, as proposed by the Company and as shown on page 4 of Schedule 2 and on page 5 of Schedule 3 of my exhibit.

4. The weekly average net operating heat rate least squares regression equations, shown on page 2 of Schedule 1 and on pages 17 through 26 of Schedule 3 of my exhibit, for use in adjusting the annual actual unit heat rates to target conditions.

Q. Mr. Rote, does this conclude your testimony?

A. Yes.

AFFIDAVIT

STATE OF FLORIDA)
)
COUNTY OF ESCAMBIA)

Docket No. 20200001-EI

Before me, the undersigned authority, personally appeared Charles Rote, who being first duly sworn, deposes and says that he is the Power Generation Division Director Business Services of Gulf Power Company, a Florida corporation, that the foregoing is true and correct to the best of his knowledge and belief. He is personally known to me.

Charles Rote

Charles Rote
Power Generation Division Director Business Svcs

Sworn to and subscribed before me by means of ✓ physical presence or ____ online notarization this 1st day of September, 2020.

Notary Public State of Florida
Kristen Carey
My Commission HH 026570
Expires 08/02/2024

K Carey

Notary Public, State of Florida at Large

(Whereupon, prefiled direct testimony of M. Ashley Sizemore was inserted.)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

M. ASHLEY SIZEMORE

Q. Please state your name, address, occupation, and employer.

A. My name is M. Ashley Sizemore. My business address is 702 N. Franklin Street, Tampa, Florida 33602. I am employed by Tampa Electric Company ("Tampa Electric" or "Company") in the position of Manager, Rates in the Regulatory Affairs department.

Q. Please provide a brief outline of your educational background and business experience.

A. I received a Bachelor of Arts degree in Political Science and a Master of Business Administration from the University of South Florida in 2005 and 2008, respectively. I joined Tampa Electric in 2010 as a Customer Service Professional. In 2011, I joined the Regulatory Affairs Department as a Rate Analyst. I spent six years in the Regulatory Affairs Department working on environmental and fuel and capacity cost recovery clauses. During the last three years as a Program Manager in Customer Experience, I managed billing and payment customer solutions, products and services. I returned to the Regulatory Affairs Department in 2020 as Manager, Rates. My duties entail managing cost recovery for fuel and purchased power, interchange sales, capacity payments, and approved environmental projects. I have ten years of electric utility experience in the areas of customer experience and project management as well as the management of fuel clause and purchased power, capacity, and environmental cost recovery clauses.

Q. Other than describing your background and qualifications, is the remainder of your testimony the same as that set forth in the testimony of Ms. Rusk filed March 2, 2020.

A. Yes, it is.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present, for the Commission's review and approval, the final true-up amounts for the period January 2019 through December 2019 for the Fuel and Purchased Power Cost Recovery Clause ("Fuel Clause") and the Capacity Cost Recovery Clause

("Capacity Clause"), as well as the Optimization Mechanism gain sharing allocation for the period.

Q. What is the source of the data which you will present by way of testimony or exhibit in this process?

A. Unless otherwise indicated, the actual data is taken from the books and records of Tampa Electric. The books and records are kept in the regular course of business in accordance with generally accepted accounting principles and practices and provisions of the Uniform System of Accounts as prescribed by the Florida Public Service Commission ("Commission").

Q. Have you prepared an exhibit in this proceeding?

A. Yes. Exhibit No. MAS-1, consisting of five documents which are described later in my testimony, was prepared under my direction and supervision.

Capacity Cost Recovery Clause

Q. What is the final true-up amount for the Capacity Clause for the period January 2019 through December 2019?

A. The final true-up amount for the Capacity Clause for the period January 2019 through December 2019 is an over–recovery of $111,228.

Q. Please describe Document No. 1 of your exhibit.

A. Document No. 1, page 1 of 4, entitled “Tampa Electric Company Capacity Cost Recovery Clause Calculation of Final True-up Variances for the Period January 2019 Through December 2019", provides the calculation for the final over–recovery of $111,228. The actual capacity cost under-recovery, including interest, was $2,067,989 for the period January 2019 through December 2019 as identified in Document No. 1, pages 1 and 2 of 4. This amount, less the $2,179,217 actual/estimated under-recovery approved in Order No. PSC-2019-0484-FOF-EI issued November 18, 2019 in Docket No. 20190001-EI, results in a final over-recovery of $111,228 for the period, as identified in Document No. 1, page 4 of 4. This amount will be applied to the calculation of the capacity cost recovery factors for the period January 2021 through December 2021.

Q. What is the estimated effect of this $111,228 over-recovery for the January 2019 through December 2019 period on residential bills during the January 2021 through

December 2021 period?

A. The $111,228 over-recovery will decrease a 1,000 kWh residential bill by approximately $0.01.

Fuel and Purchased Power Cost Recovery Clause

Q. What is the final true-up amount for the Fuel Clause for the period January 2019 through December 2019?

A. The final Fuel Clause true-up for the period January 2019 through December 2019 is an over-recovery of $35,821,098. The actual fuel cost over-recovery, including interest, was $5,079,072 for the period January 2019 through December 2019. This $5,079,072 amount, plus the $30,742,026 projected under-recovery amount approved in Order No. PSC-2019-0484-FOF-EI, issued November 18, 2019 in Docket No. 20190001-EI, results in a net over-recovery amount for the period of $35,821,098.

Q. What is the estimated effect of the $35,821,098 over-recovery for the January 2019 through December 2019 period on residential bills during the January 2021 through December 2021 period?

A. The $35,821,098 over-recovery will decrease a 1,000 kWh residential bill by approximately $1.84.

Q. Please describe Document No. 2 of your exhibit.

A. Document No. 2 is entitled "Tampa Electric Company Final Fuel and Purchased Power Over/(Under) Recovery for the Period January 2019 Through December 2019." It shows the calculation of the final fuel over-recovery of $35,821,098.

Line 1 shows the total company fuel costs of $574,069,880 for the period January 2019 through December 2019. The jurisdictional amount of total fuel costs is $574,069,880, as shown on line 2. This amount is compared to the jurisdictional fuel revenues applicable to the period on line 3 to obtain the actual over-recovered fuel costs for the period, shown on line 4. The resulting $9,140,612 over-recovered fuel costs for the period, adjustments, interest, true-up collected, and the prior period true-up shown on lines 5 through 8 respectively, constitute the actual over-recovery amount of $5,079,072 shown on line 9. The $5,079,072 actual over-recovery amount plus the $30,742,026 projected under-recovery amount shown on line 10, results in a final over-recovery amount of $35,821,098 for the period January 2019 through

December 2019, as shown on line 11.

Q. Please describe Document No. 3 of your exhibit.

A. Document No. 3 is entitled "Tampa Electric Company Calculation of True-up Amount Actual *vs.* Original Estimates for the Period January 2019 Through December 2019." It shows the calculation of the actual over-recovery compared to the estimated under-recovery for the same period.

Q. What was the total fuel and net power transaction cost variance for the period January 2019 through December 2019?

A. As shown on line A7 of Document No. 3, the fuel and net power transaction cost is $39,316,715 less than the amount originally estimated.

Q. What was the variance in jurisdictional fuel revenues for the period January 2019 through December 2019?

A. As shown on line C3 of Document No. 3, the company collected $9,052,449, or 1.6 percent greater jurisdictional fuel revenues than originally estimated.

Q. Please describe Document No. 4 of your exhibit.

A. Document No. 4 contains Commission Schedules A1 and A2 for the month of December and the year-end period-to-date summary of transactions for each of Commission Schedules A6, A7, A8, A9, as well as capacity information on Schedule A12.

Q. Please describe Document No. 5 of your exhibit.

A. Document No. 5 provides the capital costs and fuel savings for the Big Bend Units 1-4 ignition conversion projects for the period January 2019 through December 2019. This document also contains the capital structure components and cost rates relied upon to calculate the revenue requirements rate of return on capital projects recovered through the fuel clause.

The Big Bend Units 1-4 ignition conversion project capital costs, including depreciation and return, for the period are less than the fuel savings resulting from the project, and provide a net benefit to customers, as shown on Document No. 5, page 1, line 33. Therefore, the Big Bend Units 1-4 ignition conversion project capital costs should be recovered through the fuel clause in accordance with FPSC Order No. PSC-2014-0309-PAA-EI, issued in Docket No. 20140032-EI on June 12, 2014.

Q. Have you incorporated the Florida Corporate Income Tax Reduction, effective January 1, 2019, into the company's calculated revenue requirement?

A. Yes. The change in the corporate income tax rate, announced in September 2019 and retroactive to January 1, 2019, resulted in an adjustment to the capital cost recovery for the Big Bend Units 1-4 ignition conversion project. Document No. 5 of my exhibit shows the adjustment on Page 1, Line 26, and the original and post-state tax reform revenue requirement rate of return calculations are shown on Pages 2 through 5.

Optimization Mechanism

Q. Was Tampa Electric's sharing of Optimization Mechanism gains allocated in accordance with FPSC Order No. PSC-2017-0456-S-EI, issued in Docket Nos. 20170210-EI and 20160160-EI, on November 27, 2017?

A. Yes. As shown in the testimony and exhibit of Tampa Electric witness John C. Heisey filed contemporaneously in this docket, the sharing of Optimization Mechanism gains was allocated in accordance with FPSC Order No. PSC-2017-0456-S-EI. Total gains were $6,468,033. Under the sharing mechanism, Tampa Electric customers receive $5,287,213, and the company earned an incentive of $1,180,820 as a result of the company's Optimization Mechanism activities during 2019. Customers received the gains from these transactions during 2019, and Tampa Electric requests Commission approval to collect the company's $1,180,820 incentive in its 2021 fuel factors.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

M. ASHLEY SIZEMORE

Q. Please state your name, address, occupation, and employer.

A. My name is M. Ashley Sizemore. My business address is 702 N. Franklin Street, Tampa, Florida 33602. I am employed by Tampa Electric Company ("Tampa Electric" or "company") in the position of Manager, Rates in the Regulatory Affairs department.

Q. Have you previously filed testimony in Docket No. 20200001-EI?

A. Yes, I submitted direct testimony on June 3, 2020, July 27, 2020 and revised the July 27, 2020 testimony on August 12, 2020.

Q. Has your job description, education, or professional experience changed since you last filed testimony in this docket?

A. No, it has not.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present, for Commission review and approval, the proposed annual capacity cost recovery factors, and the proposed annual levelized fuel and purchased power cost recovery factors for January 2021 through December 2021. I also describe significant events that affect the factors and provide an overview of the composite effect on the residential bill of changes in the various cost recovery factors for 2021.

Q. Have you prepared an exhibit to support your direct testimony?

A. Yes. Exhibit No. MAS-3, consisting of three documents, was prepared under my direction and supervision. Document No. 1, consisting of four pages, is furnished as support for the projected capacity cost recovery factors. Document No. 2, which is furnished as support for the proposed levelized fuel and purchased power cost recovery factors, includes Schedules E1 through E10 for January 2021 through December 2021 as well as Schedule H1 for 2018 through 2021. Document No. 3 provides a comparison of retail residential fuel revenues under the inverted or tiered fuel rate, which demonstrates that the tiered rate is revenue neutral.

Capacity Cost Recovery

Q. Are you requesting Commission approval of the projected capacity cost recovery factors for the company's various rate schedules?

A. Yes. The capacity cost recovery factors, prepared under my direction and supervision, are provided in Exhibit No. MAS-3, Document No. 1, page 3 of 4.

Q. What payments are included in Tampa Electric's capacity cost recovery factors?

A. Tampa Electric is requesting recovery of capacity payments for power purchased for retail customers, excluding optional provision purchases for interruptible customers, through the capacity cost recovery factors. As shown in Exhibit No. MAS-3, Document No. 1, page 2 of 4. Tampa Electric requests recovery of $353,890 after jurisdictional separation, prior year true-up, and application of the revenue tax factor, for estimated expenses in 2021.

Q. Please summarize the proposed capacity cost recovery factors by metering voltage level for January 2021 through December 2021.

A.

Rate Class and Metering Voltage	**Capacity Cost Cents per kWh**	**Recovery Factor $ per kW**
RS Secondary	0.002	
GS and CS Secondary	0.002	
GSD, SBF Standard		
Secondary		0.01
Primary		0.01
Transmission		0.01
IS, IST, SBI		
Primary		0.00
Transmission		0.00
GSD Optional		
Secondary	0.002	
Primary	0.002	
Transmission	0.002	
LS1 Secondary	0.000	

These factors are shown in Exhibit No. MAS-3, Document No. 1, page 3 of 4.

Q. How does Tampa Electric’s proposed average capacity cost recovery factor of 0.002 cents per kWh compare to the factor for June 2020 through December 2020?

A. The proposed capacity cost recovery factor of .002 cents per kWh for the January 2021 through December 2021 period is 0.014 cents per kWh (or $0.14 per 1,000 kWh) greater than the average capacity cost recovery factor credit of .012 cents per kWh for the June 2020 through December 2020 period.

Fuel and Purchased Power Cost Recovery Factor

Q. What is the appropriate amount of the levelized fuel and purchased power cost recovery factor for the year 2021?

A. The appropriate amount for the 2021 period is 3.167 cents per kWh before the application of the time of use multipliers for on-peak or off-peak usage. Schedule E1-E of Exhibit No. MAS-3, Document No. 2, shows the appropriate value for the total fuel and purchased power cost recovery factor for each metering voltage level as projected for the period January 2021 through December 2021.

Q. Please describe the information provided on Schedule E1-C.

A. The Generating Performance Incentive Factor ("GPIF"), true-up factors, and Optimization Mechanism factor are provided on Schedule E1-C. Tampa Electric has calculated a GPIF reward of $2,858,056, which is included in the calculation of the total fuel and purchased power cost recovery factors. In addition, Schedule E1-C indicates the net true-up amount to be applied during the January 2021 through December 2021 period. The net true-up amount is an under-recovery of $25,479,055. Lastly, Schedule E1-C indicates the Optimization Mechanism gain of $1,180,820.

Q. Please describe the information provided on Schedule E1-D.

A. Schedule E1-D presents Tampa Electric's on-peak and off-peak fuel adjustment factors for January 2021 through December 2021. The schedule also presents Tampa Electric's levelized fuel cost factors at each metering level.

Q. Please describe the information presented on Schedule E1-E.

A. Schedule E1-E presents the standard, tiered, on-peak and off-peak fuel adjustment factors at each metering voltage to be applied to customer bills.

Q. Please describe the information provided in Document No. 3.

A. Exhibit No. MAS-3, Document No. 3 demonstrates that the tiered rate structure is designed to be revenue neutral so that the company will recover the same fuel costs as it would under the levelized fuel approach.

Q. Please summarize the proposed fuel and purchased power cost recovery factors by metering voltage level for January 2021 through December 2021.

A.

Metering Voltage Level	**Fuel Charge Factor (Cents per kWh)**
Secondary	3.167
Tier I (Up to 1,000 kWh)	2.856
Tier II (Over 1,000 kWh)	3.856
Distribution Primary	3.135
Transmission	3.104
Lighting Service	3.136
Distribution Secondary	3.335(on-peak)
	3.095(off-peak)

Metering Voltage Level	Fuel Charge Factor (Cents per kWh)
Distribution Primary	3.302(on-peak)
	3.064(off-peak)
Transmission	3.268(on-peak)
	3.033(off-peak)

Q. How does Tampa Electric's proposed levelized fuel adjustment factor of 3.167 cents per kWh compare to the levelized fuel adjustment factor for the June 2020 through December 2020 period?

A. The proposed fuel charge factor of 3.167 cents per kWh is 0.529 cents per kWh (or $5.29 per 1,000 kWh) higher than the average fuel charge factor of 2.638 cents per kWh for the June 2020 through December 2020 period.

Wholesale Incentive Benchmark and Optimization Mechanism

Q. Will Tampa Electric project a 2021 wholesale incentive benchmark that is derived in accordance with Order No. PSC-2001-2371-FOF-EI issued in Docket No. 20010283-EI?

A. No. Effective January 1, 2018, as authorized by FPSC Order No. PSC-2017-0456-S-EI, issued in Docket No. 20160160-EI on November 27, 2017, the company's Optimization

Mechanism replaced the existing short-term wholesale sales incentive mechanism, and as a result no wholesale incentive benchmark is required for the 2021 projection.

Cost Recovery Factors

Q. What is the composite effect of Tampa Electric’s proposed changes in its base, capacity, fuel and purchased power, environmental, energy conservation, storm protection plan cost recovery factors, and gross receipts tax on a 1,000 kWh residential customer’s bill?

A. The composite effect on a residential bill for 1,000 kWh is an increase of $7.56 beginning January 2021, when compared to the September 2020 through December 2020 charges. These amounts are shown in Exhibit No. MAS-3, Document No. 2, on Schedule E10.

Q. When should the new rates take effect?

A. The new rates should take effect concurrent with meter readings for the first billing cycle for January 2021.

Q. Does this conclude your direct testimony?

A. Yes, it does.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

M. ASHLEY SIZEMORE

Q. Please state your name, address, occupation, and employer.

A. My name is M. Ashley Sizemore. My business address is 702 N. Franklin Street, Tampa, Florida 33602. I am employed by Tampa Electric Company ("Tampa Electric" or "company") in the position of Manager, Rates, in the Regulatory Affairs department.

Q. Please provide a brief outline of your educational background and business experience.

A. I received a Bachelor of Arts degree in Political Science and a Master of Business Administration from the University of South Florida in 2005 and 2008, respectively. I joined Tampa Electric in 2010 as a Customer Service Professional. In 2011, I joined the Regulatory Affairs Department as a Rate Analyst. I spent six years in the Regulatory Affairs Department working on environmental, fuel and capacity cost recovery clauses. During the last three years as a Program Manager in

Customer Experience, I managed billing and payment customer solutions, products and services. I returned to the Regulatory Affairs Department in 2020 as Manager, Rates. My duties entail managing cost recovery for fuel and purchased power, interchange sales, capacity payments, and approved environmental projects. I have ten years of electric utility experience in the areas of customer experience and project management as well as the management of fuel and purchased power, capacity, and environmental cost recovery clauses.

Q. What is the purpose of your direct testimony?

A. The purpose of my testimony is to present, for Commission review and approval, the calculation of the January 2020 through December 2020 fuel and purchased power and capacity actual/estimated true-up amounts to be recovered in the January 2021 through December 2021 projection period. My testimony addresses the recovery of the fuel and purchased power costs as well as capacity costs for the year 2020, based on six months of actual data and six months of estimated data. This information will be used in the determination of the 2021 fuel and purchased power and capacity cost recovery factors.

Q. Have you prepared an exhibit to support your direct testimony?

A. Yes, I have prepared Exhibit No. MAS-2, which consists of four documents. Document No. 1 includes schedules E1-A, E1-B, E-2, E-3, E-4, E-5, E-6, E-7, E-8, and E-9, which provide the actual/estimated fuel and purchased power cost recovery true-up amount for the period January 2020 through December 2020. Document No. 2 provides the actual/estimated capacity cost recovery true-up amount for the period January 2020 through December 2020. Document No. 3 provides the actual/estimated capital costs during the period of January 2020 through December 2020 for projects authorized for recovery through the fuel clause. Document No. 3 also provides the capital structure components and cost rates relied upon to calculate the revenue requirement rate of return for such projects. Document No. 4 provides the calculation for the Lake Hancock stipulated issue fuel savings. These documents are furnished as support for the actual/estimated true-up amount for this period.

Fuel and Purchased Power Cost Recovery Factors

Q. What has Tampa Electric calculated as the estimated net true-up amount for the current period to be applied in the January 2021 through December 2021 fuel and purchased power cost recovery factors?

A. The estimated net true-up amount applicable for the period of January 2021 through December 2021 is an under-recovery of $25,479,055.

Q. How did Tampa Electric calculate the estimated net true-up to be applied in the January 2021 through December 2021 fuel and purchased power cost recovery factors?

A. The net true-up amount to be recovered in 2021 does not include the final true-up amount for the period January 2019 through December 2019 because this amount was returned to customers during 2020 in Tampa Electric’s fuel mid-course factors, as approved in Order No. PSC-2020-0154-PCO-EI, issued May 14, 2020 in Docket No. 20200001-EI. The actual/estimated true-up amount for the period January 2020 through December 2020 is included in the January 2021 through December 2021 fuel and purchased power cost recovery factors. This calculation is shown on Schedule E1-A of Exhibit No. MAS-2, Document No. 1.

Q. What did Tampa Electric calculate as the actual/estimated fuel and purchased power cost recovery amount for the period January 2020 through December 2020?

A. The net 2020 actual/estimated fuel and purchased power cost recovery true-up is an under-recovery of $61,300,153 for the January 2020 through December 2020 period. This includes adjustments to reflect the company's mid-course correction true-up amounts. It is the actual/estimated under-recovery amount for the period January 2020 through December 2020, less the projected over-recovery true-up included in the period June 2020 through December 2020 mid-course correction factors, plus the difference between the 2019 actual/estimated true-up amount included in the original 2020 factors and the amount actually refunded before the mid-course correction factors became effective. The actual/estimated true-up for the period January 2020 through December 2020 is an under-recovery of $43,367,307. The detailed calculation supporting the actual/estimated current period true-up is shown in Exhibit No. MAS-2, Document No. 1 on Schedule E1-B. In addition, the calculation is shown on Schedule E1-A of Exhibit No. MAS-2, Document No. 1.

Q. Please explain the fuel savings credit for Lake Hancock Solar that was booked in February 2020.

A. In Order No. PSC-2018-0571, the Commission approved Tampa Electric's proposed set of Stipulations, wherein the company committed that if the 2019 actual fuel savings associated with the incremental 5 MW and the additional 17.7 MW of the Lake Hancock Solar project not included in the Second SoBRA did not equal or exceed $1,000,000, then the company would refund the shortfall to customers. The refund, reflected in February's A-Schedule, was $236,322. This is shown in Exhibit No. MAS-2, Document No. 1 on Schedule E1-B. In addition, the calculation is shown in Exhibit No. MAS-2, Document No. 4.

Q. What was the actual 2019 fuel savings associated with Lake Hancock's incremental 5 MW and additional 17.7 MW that was not included in the Second SoBRA tranche?

A. The actual fuel savings associated with Lake Hancock's incremental 5 MW and additional 17.7 MW not included in the second SoBRA tranche is $763,678. Tampa Electric refunded the difference of $236,322 to the customers.

Q. Were there any additional adjustments to the Fuel and Purchased Power cost recovery clause?

A. Yes. In July, Tampa Electric received a refund related to the Transco rate case settlement in the amount of $461,004 for charges incurred during the period of March 2019 through May 2020 (Docket No.: RP18-1126-003, Order Document No. 20200324-3028 filed on March 24, 2020).

Capacity Cost Recovery Clause

Q. What has Tampa Electric calculated as the estimated net true-up amount to be applied in the January 2021 through December 2021 capacity cost recovery factors?

A. The estimated net true-up amount applicable for January 2021 through December 2021 is an over-recovery of $1,771,480 as shown in Exhibit No. MAS-2, Document No. 2, page 1 of 4.

Q. How did Tampa Electric calculate the estimated net true-up amount to be applied in the January 2021 through December 2021 capacity cost recovery factors?

A. The net true-up amount to be recovered in the 2021 capacity cost recovery factors includes the sum of the final true-up amount for 2019 and the actual/estimated true-up amount for January 2020 and December 2020.

Q. What did Tampa Electric calculate as the final capacity cost recovery true-up amount for 2019?

A. The final 2019 true-up is an over-recovery of $111,228. The actual capacity cost under-recovery, including interest, was $2,067,989 for the period January 2019 through December 2019. This amount, less the $2,179,217 actual/estimated under-recovery amount approved in Order No. PSC-2019-0484-FOF-EI, issued November 18, 2019, in Docket No. 20190001-EI results in a net over-recovery amount for the period of $111,228 as identified in Exhibit No. MAS-2, Document No. 2, page 1 of 4.

Q. What did Tampa Electric calculate as the actual/estimated capacity cost recovery true-up amount for the period January 2020 through December 2020?

A. The actual/estimated true-up amount is an over-recovery of $5,870,171 as shown on Exhibit No. MAS-2, Document No. 2, page 1 of 4.

Q. What did Tampa Electric calculate as the net capacity cost recovery true-up amount for the period January 2020 through December 2020?

A. The net capacity cost recovery true-up amount for the period January 2020 through December 2020 is an over-recovery of $1,771,480. This calculation is shown on Exhibit No. MAS-2, Document No. 2, page 1 of 4.

Q. Please explain the credit of $4,856,329 that is reflected in the month of February and the credit of $4,069,905 that is reflected in the month of June on line 12 of Exhibit No. MAS-2, Document No. 2, page 2 of 4.

A. Pursuant to paragraph 6(n) of the 2017 Amended and Restated Stipulation and Settlement agreement, "…the difference between the cumulative base revenues since the implementation of the initial SoBRA factor and the cumulative base revenues that would have resulted if the revised SoBRA factor (for cost and in-service date true-ups) had been in place during the same time period will be trued up with interest at the AFUDC rate shown in Exhibit B used for the projects, and will be made through a one-time, twelve-month adjustment through the CCR clause." As submitted for Commission review and approval in Docket No. 20200144-EI, an estimated true-up for the First and Second SoBRAs totaling $4,856,329 was credited to the capacity clause in February 2020, and any additional adjustment required will be made upon resolution of Docket No. 20200144-EI. The June 2020 credit to the capacity clause represents the estimated true-up amount due to customers for the Third SoBRA actual in-service dates and will be adjusted as needed upon Commission review and approval of the final true-up amounts for the actual in-service dates and installed costs of the projects. This amount is expected to be finalized during 2021.

Capital Projects Approved for Fuel Clause Recovery

Q. Please describe the capital project costs that have been authorized for recovery through the fuel clause.

A. Document No. 3 of Exhibit No. MAS-2 provides the capital cost and fuel savings for the Big Bend Units 1 through 4 ignition conversion project for the period January 2020 through December 2020. This document also contains the capital structure components and cost rates relied upon to calculate the revenue requirement rate of return on capital projects recovered through the fuel clause.

Collection of the Big Bend Units 1 through 4 ignition conversion project capital costs was completed in May 2020. These costs, including depreciation and return, were less than the project fuel savings, as shown on Exhibit No. MAS-2, Document No. 3, Page 1, line 33.

Therefore, the Big Bend Units 1 through 4 ignition conversion project capital costs should be recovered through the fuel clause in accordance with FPSC Order No. PSC-2014-0309-PAA-EI, issued in Docket No. 20140032-EI on June 12, 2014.

Q. Does this conclude your direct testimony?

A. Yes, it does.

(Whereupon, prefiled direct testimony of Jeremy B. Cain was inserted.)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

JEREMY B. CAIN

Q. Please state your name, business address, occupation, and employer.

A. My name is Jeremy Cain. My business address is 702 North Franklin Street, Tampa, Florida 33602. I am employed by Tampa Electric Company ("Tampa Electric" or "company") in the position of Manager of Asset Management, Bayside Station.

Q. Please provide a brief outline of your educational background and business experience.

A. I received a Bachelor of Science degree in Mechanical Engineering in 2003 from the University of New Brunswick, Canada, and I am a registered Professional Engineer in Canada. I have accumulated 10 years of experience in the electric utility industry, with experience in the areas of unit maintenance manager, project manager for a unit upgrade, operations manager for that plant, as well as various other engineering positions, including responsibility for physical asset management. In my current role, I am responsible for development of Tampa Electric’s Asset Management programs and processes, specifically for the Bayside Power Station, and coordinating these programs with Asset Management programs throughout Energy Supply. Asset Management processes include work management processes, reliability programs, information technology, operational and capital investment analysis, recommendations, and planning to maintain and improve the performance of the generating units.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present Tampa Electric's actual performance results from unit equivalent availability and heat rate used to determine the Generating Performance Incentive Factor (“GPIF”) for the period January 2019 through December 2019. I will also compare these results to the targets established for the period.

Q. Have you prepared an exhibit to support your testimony?

A. Yes, I prepared Exhibit No. JBC-1, consisting of two documents. Document No. 1, entitled “GPIF Schedules” is consistent with the GPIF Implementation Manual approved by the Commission. Document No. 2 provides the company’s Actual Unit Performance Data for the 2019 period.

Q. Which generating units on Tampa Electric's system are included in the determination of the GPIF?

A. Polk Units 1 and 2 and Bayside Units 1 and 2 are included in the calculation of the GPIF.

Q. Have you calculated the results of Tampa Electric's performance under the GPIF during the January 2019 through December 2019 period?

A. Yes, I have. This is shown on Document No. 1, page 4 of 22. Based upon 5.274 Generating Performance Incentive Points ("GPIP"), the result is a reward amount of $2,858,056 for the period.

Q. Please proceed with your review of the actual results for the January 2019 through December 2019 period.

A. On Document No. 1, page 3 of 22, the actual average common equity for the period is shown on line 14 as $3,015,639,377. This produces the maximum penalty or reward amount of $5,419,348 as shown on line 23.

Q. Will you please explain how you arrived at the actual equivalent availability results for the four units included within the GPIF?

A. Yes. Operating data for each of the units is filed monthly with the Commission on the Actual Unit Performance Data form. Additionally, outage information is reported to the Commission on a monthly basis. A summary of this data for the 12 months provides the basis for the GPIF.

Q. Are the actual equivalent availability results shown on Document No. 1, page 6 of 22, column 2, directly applicable to the GPIF table?

A. No. Adjustments to actual equivalent availability may be required as noted in Section 4.3.3 of the GPIF Manual. The actual equivalent availability including the required adjustment is shown on Document No. 1, page 6 of 22, column 4. The necessary adjustments as prescribed in the GPIF Manual are further defined by a letter dated October 23, 1981, from Mr. J. H. Hoffsis of the Commission's Staff. The adjustments for each unit are as follows:

Polk Unit No. 1

On this unit, 720 planned outage hours were originally scheduled for 2019. Actual outage activities required 419 planned outage hours. Consequently, the actual equivalent availability of 78.9 percent is adjusted to 77.0 percent, as shown on Document No. 1, page 7 of 22.

Polk Unit No. 2

On this unit, 576 planned outage hours were originally scheduled for 2019. Actual outage activities required 391.4 planned outage hours. Consequently, the actual equivalent availability of 92.6 percent is adjusted to 90.6 percent, as shown on Document No. 1, page 8 of 22.

Bayside Unit No. 1

On this unit, 624 planned outage hours were originally scheduled for 2019. Actual outage activities required 973.6 planned outage hours. Consequently, the actual equivalent availability of 85.1 percent is adjusted to 89.1 percent, as shown on Document No. 1, page 9 of 22.

Bayside Unit No. 2

On this unit, 671 planned outage hours were originally scheduled for 2019. Actual outage activities required 998 planned outage hours. Consequently, the actual equivalent availability of 85.5 percent is adjusted to 89.0 percent, as shown on Document No. 1, page 10 of 22.

Q. How did you arrive at the applicable equivalent availability points for each unit?

A. The final adjusted equivalent availability for each unit is shown on Document No. 1, page 6 of 22, column 4. This number is incorporated in the respective GPIP table for each unit, shown on pages 17 through 20 of 22. Page 4 of 22 summarizes the weighted equivalent availability points to be awarded or penalized.

Q. Will you please explain the heat rate results relative to the GPIF?

A. The actual heat rate and adjusted actual heat rate for Tampa Electric's four GPIF units are shown on Document No. 1, page 6 of 22. The adjustment was developed based on the guidelines of Section 4.3.16 of the GPIF Manual. This procedure is further defined by a letter dated October 23, 1981, from Mr. J. H. Hoffsis of the FPSC Staff. The final adjusted actual heat rates are also shown on page 5 of 22, column 9. The heat rate value is incorporated in the respective GPIP table for each unit, shown on pages 17 through 20 of 22. Page 4 of 22 summarizes the weighted heat rate points to be awarded or penalized.

Q. What is the overall GPIP for Tampa Electric for the January

2019 through December 2019 period?

A. This is shown on Document No. 1, page 2 of 22. The weighting factors shown on page 4 of 22, column 3, plus the equivalent availability points and the heat rate points shown on page 4 of 22, column 4, are substituted within the equation found on page 22 of 22. The resulting value of 5.274 is in the GPIF table on page 2 of 22, and the reward amount of $2,858,056 is calculated using linear interpolation.

Q. Are there any other constraints set forth by the Commission regarding the magnitude of incentive dollars?

A. Yes. Incentive dollars are not to exceed 50 percent of fuel savings. Tampa Electric met this constraint, limiting the total potential reward and penalty incentive dollars to $5,419,348 as shown in Document No. 1, pages 2 and 3.

Q. Does this conclude your testimony?

A. Yes, it does.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

JEREMY B. CAIN

Q. Please state your name, address, occupation, and employer.

A. My name is Jeremy B. Cain. My business address is 702 N. Franklin Street, Tampa, Florida 33602. I am employed by Tampa Electric Company ("Tampa Electric" or "company") in the position of Manager, Asset Management.

Q. Please provide a brief description of your educational background and work experience.

A. I received a Bachelor of Science degree in Mechanical Engineering in 2003 from the University of New Brunswick, Canada, and I am a registered Professional Engineer in Canada. I have over 11 years of experience in the electric utility industry, specifically in the roles of unit maintenance manager, project manager for a unit upgrade, operations manager for that plant, as well as various other engineering positions, including responsibility for asset management. In my current role, I am responsible for development of Tampa Electric’s Asset Management programs and processes, specifically for the Bayside Power Station, and coordinating these programs with the Asset Management processes throughout Energy Supply. Asset Management programs include work management processes, reliability programs, information technology, operational and capital investment analysis, recommendations, and planning in order to maintain and improve the performance of the generating units.

Q. What is the purpose of your testimony?

A. My testimony describes Tampa Electric’s methodology for determining the various factors required to compute the Generating Performance Incentive Factor (“GPIF”) as ordered by the Commission.

Q. Have you prepared an exhibit to support your direct testimony?

A. Yes. Exhibit No. JC-1, consisting of two documents, was prepared under my direction and supervision. Document No. 1 contains the GPIF schedules. Document No. 2 is a summary of the GPIF targets for the 2021 period.

Q. Which generating units on Tampa Electric's system are included in the determination of the GPIF?

A. Four natural gas combined cycle units and one coal unit are included. These are Polk Units 1 and 2, Bayside Units 1 and 2, and Big Bend Unit 4.

Q. Does your exhibit comply with the Commission's approved GPIF methodology?

A. Yes. In accordance with the GPIF Manual, the GPIF units selected represent no less than 80 percent of the estimated system net generation. The units Tampa Electric proposes to use for the period January 2021 through December 2021 represent 87.4 percent of the total forecasted system net generation for this period.

To account for the concerns presented in the testimony of Commission Staff witness Sidney W. Matlock during the 2005 fuel hearing, Tampa Electric removes outliers from the calculation of the GPIF targets. The methodology was approved by the Commission in Order No. PSC-2006-1057-FOF-EI issued in Docket No. 20060001-EI on December 22, 2006.

Q. Did Tampa Electric identify any outages as outliers?

A. Yes, Polk Unit 1, Polk Unit 2, and Bayside Unit 1 outages were identified as outliers and were removed.

Q. Did Tampa Electric make any other adjustments?

A. Yes. As allowed per Section 4.3 of the GPIF Implementation Manual, the Forced Outage and Maintenance Outage Factors were adjusted to reflect recent unit performance and known unit modifications or equipment changes.

Q. Please describe how Tampa Electric developed the various factors associated with GPIF.

A. Targets were established for equivalent availability and heat rate for each unit considered for the 2021 period. A range of potential improvements and degradations were determined for each of these metrics.

Q. How were the target values for unit availability determined?

A. The Planned Outage Factor (“POF”) and the Equivalent Unplanned Outage Factor (“EUOF”) were subtracted from 100 percent to determine the target Equivalent Availability Factor ("EAF"). The factors for each of the five units included within the GPIF are shown on page 5 of Document No. 1.

To give an example for the 2021 period, the projected EUOF for Bayside Unit 1 is 2.3 percent, the POF is 3.8 percent. Therefore, the target EAF for Bayside Unit 1 equals 93.9 percent or:

$$100\% - (2.3\% + 3.8\%) = 93.9\%$$

This is shown on Page 4, column 3 of Document No. 1.

Q. How was the potential for unit availability improvement determined?

A. Maximum equivalent availability is derived using the following formula:

$$EAF_{MAX} = 1 - [0.80\ (EUOF_T) + 0.95\ (POF_T)]$$

The factors included in the above equations are the same factors that determine the target equivalent availability. Calculating the maximum incentive points, a 20 percent reduction in EUOF, plus a five percent reduction in the POF is necessary. Continuing with the Bayside Unit 1 example:

$$EAF_{MAX} = 1 - [0.80\ (2.3\%) + 0.95\ (3.8\%)] = 94.5\%$$

This is shown on page 4, column 4 of Document No. 1.

Q. How was the potential for unit availability degradation determined?

A. The potential for unit availability degradation is significantly greater than the potential for unit availability improvement. This concept was discussed extensively during the development of the incentive. To incorporate this biased effect into the unit availability tables, Tampa Electric uses a potential degradation range equal to twice the potential improvement. Consequently, minimum equivalent availability is calculated using the following formula:

$$EAF_{MIN} = 1 - [1.40\ (EUOF_T) + 1.10\ (POF_T)]$$

Again, continuing using the Bayside Unit 1 example,

$$EAF_{MIN} = 1 - [1.40\ (2.3\%) + 1.10\ (3.8\%)] = 92.6\%$$

The equivalent availability maximum and minimum for the other four units are computed in a similar manner.

Q. How did Tampa Electric determine the Planned Outage, Maintenance Outage, and Forced Outage Factors?

A. The company’s planned outages for January through December 2021 are shown on page 17 of Document No. 1. Two GPIF units have a major planned outage of 28 days or greater in 2021; therefore, two Critical Path Method Diagrams are provided.

Planned Outage Factors are calculated for each unit. For example, Bayside Unit 1 is scheduled for planned outages from March 15, 2021 to March 28, 2021. There are 336 planned outage hours scheduled for the 2021 period, with a total of 8,760 hours during this 12-month period. Consequently, the POF for Bayside Unit 1 is 3.8 percent or:

$$\frac{336}{8{,}760} \times 100\% = 3.8\%$$

The factor for each unit is shown on pages 5 and 12 through 16 of Document No. 1. Polk Unit 1 has a POF of 7.7 percent. Polk Unit 2 has a POF of 16.2 percent. Bayside Unit 2 has a POF of 3.8 percent, and Big Bend Unit 4 has a POF of 16.2 percent.

Q. How did you determine the Forced Outage and Maintenance Outage Factors for each unit?

A. Projected factors are based upon historical unit performance. For each unit, the three most recent July through June annual periods formed the basis of the target development. Historical data and target values are analyzed to assure applicability to current conditions of operation. This provides assurance that any periods of abnormal operations or recent trends having material effect can be taken into consideration. These target factors are additive and result in a EUOF of 2.3 percent for Bayside Unit 1. The EUOF of Bayside Unit 1 is verified by the data shown on page 15, lines 3, 5, 10, and 11 of Document No. 1 and calculated using the following formula:

$$EUOF = \frac{(EFOH + EMOH)}{PH} \times 100\%$$

Or

$$EUOF = \frac{(95 + 106)}{8,760} \times 100\% = 2.3\%$$

Relative to Bayside Unit 1, the EUOF of 2.3 percent forms the basis of the equivalent availability target development as shown on pages 4 and 5 of Document No. 1.

Polk Unit 1

The projected EUOF for this unit is 14.6 percent. The unit will have two planned outages in 2021, and the POF is 7.7 percent. Therefore, the target equivalent availability for this unit is 77.7 percent.

Polk Unit 2

The projected EUOF for this unit is 3.2 percent. The unit will have two planned outages in 2021, and the POF is 16.2 percent. Therefore, the target equivalent availability for this unit is 80.6 percent.

Bayside Unit 1

The projected EUOF for this unit is 2.3 percent. The unit will have one planned outage in 2021, and the POF is 3.8 percent. Therefore, the target equivalent availability for this unit is 93.9 percent.

Bayside Unit 2

The projected EUOF for this unit is 5.2 percent. The unit will have one planned outage in 2021, and the POF is 3.8 percent. Therefore, the target equivalent availability for this unit is 90.9 percent.

Big Bend Unit 4

The projected EUOF for this unit is 29.9 percent. The unit will have two planned outages in 2021, and the POF is 16.2 percent. Therefore, the target equivalent availability for this unit is 54 percent.

Q. Please summarize your testimony regarding EAF.

A. The GPIF system weighted EAF of 88.4 percent is shown on page 5 of Document No. 1.

Q. Why are Forced and Maintenance Outage Factors adjusted for planned outage hours?

A. The adjustment makes the factors more accurate and comparable. A unit in a planned outage stage or reserve shutdown stage cannot incur a forced or maintenance outage. To demonstrate the effects of a planned outage, note the Equivalent Unplanned Outage Rate and Equivalent

Unplanned Outage Factor for Bayside Unit 1 on page 15 of Document No. 1. Except for the month of March, the Equivalent Unplanned Outage Rate and Equivalent Unplanned Outage Factor are equal. This is because no planned outages are scheduled for these months. During the month of March, the Equivalent Unplanned Outage Rate exceeds the Equivalent Unplanned Outage Factor due to the scheduled planned outages. Therefore, the adjusted factors apply to the period hours after the planned outage hours have been extracted.

Q. Does this mean that both rate and factor data are used in calculated data?

A. Yes. Rates provide a proper and accurate method of determining unit metrics, which are subsequently converted to factors. Therefore,

$$EFOF + EMOF + POF + EAF = 100\%$$

Since factors are additive, they are easier to work with and to understand.

Q. Has Tampa Electric prepared the necessary heat rate data required for the determination of the GPIF?

A. Yes. Target heat rates and ranges of potential operation have been developed as required and have been adjusted to reflect the afore mentioned agreed upon GPIF methodology.

Q. How were the targets determined?

A. Net heat rate data for the three most recent July through June annual periods formed the basis for the target development. The historical data and the target values are analyzed to assure applicability to current conditions of operation. This provides assurance that any period of abnormal operations or equipment modifications having material effect on heat rate can be taken into consideration.

Q. How were the ranges of heat rate improvement and heat rate degradation determined?

A. The ranges were determined through analysis of historical net heat rate and net output factor data. This is the same data from which the net heat rate versus net output factor curves have been developed for each unit. This information is shown on pages 25 through 29 of Document No. 1.

Q. Please elaborate on the analysis used in the determination of the ranges.

A. The net heat rate versus net output factor curves are the result of a first order curve fit to historical data. The standard error of the estimate of this data was determined, and a factor was applied to produce a band of potential improvement and degradation. Both the curve fit and the standard error of the estimate were performed by the computer program for each unit. These curves are also used in post-period adjustments to actual heat rates to account for unanticipated changes in unit dispatch and fuel.

Q. Please summarize your heat rate projection (Btu/Net kWh) and the range about each target to allow for potential improvement or degradation for the 2021 period.

A. The heat rate target for Polk Unit 1 is 9,684 Btu/Net kWh with a range of ±664 Btu/Net kWh. The heat rate target for Polk Unit 2 is 6,940 Btu/Net kWh with a range of ±185 Btu/Net kWh. The heat rate for Bayside Unit 1 is 7,352 Btu/Net kWh with a range of ±108 Btu/Net kWh. The heat rate target for Bayside Unit 2 is 7,439 Btu/Net kWh with a range of ±121 Btu/Net kWh. The heat rate target for Big

Bend Unit 4 is 11,576 Btu/Net kWh with a range of ±615 Btu/Net kWh. A zone of tolerance of ±75 Btu/Net kWh is included within a range for each target. This is shown on page 4, and pages 7 through 11 of Document No. 1.

Q. Do these heat rate targets and ranges meet the Commission’s requirements?

A. Yes.

Q. After determining the target values and ranges for average net operating heat rate and equivalent availability, what is the next step in determining the GPIF targets?

A. The next step is to calculate the savings and weighting factor to be used for both average net operating heat rate and equivalent availability. This is shown in Document No. 1, pages 7 through 11. The baseline production costing analysis was performed to calculate the total system fuel cost if all units operated at target heat rate and target availability for the period. This total system fuel cost of $459,381,860 is shown on Document No. 1, page 6, column 2. Multiple production cost simulations were performed to calculate total system fuel cost with each unit individually operating at maximum improvement in equivalent availability and each station operating at maximum improvement in average net operating heat rate. The respective savings are shown on page 6, column 4 of Document No. 1.

Column 4 totals $14,003,920 which reflects the savings if all of the units operated at maximum improvement. A weighting factor for each metric is then calculated by dividing unit savings by the total. For Bayside Unit 1, the weighting factor for average net operating heat rate is 10.83 percent as shown in the right-hand column on Document No. 1, page 6. Pages 7 through 11 of Document No. 1 show the point table, the Fuel Savings/(Loss) and the equivalent availability or heat rate value. The individual weighting factor is also shown. For example, as shown on page 10 of Document No. 1, if Bayside Unit 1, operates at 7,244 average net operating heat rate, fuel savings would equal $1,516,300 and +10 average net operating heat rate points would be awarded.

The GPIF Reward/Penalty table on page 2 of Document No. 1 is a summary of the tables on pages 7 through 11. The left-hand column of this document shows the incentive points for Tampa Electric. The center column shows the total fuel savings and is the same amount as shown on page 6, column 4, or $14,003,920. The right-hand column of page 2 is the estimated reward or penalty based upon performance.

Q. How was the maximum allowed incentive determined?

A. Referring to page 3, line 14, the estimated average common equity for the period January through December 2021 is $3,589,402,384. This produces the maximum allowed jurisdictional incentive of $12,003,035 shown on line 21.

Q. Are there any constraints set forth by the Commission regarding the magnitude of incentive dollars?

A. Yes. As Order No. PSC-2013-0665-FOF-EI, issued in Docket No. 20130001-EI on December 18, 2013 states, incentive dollars are not to exceed 50 percent of fuel savings. Page 2 of Document No. 1 demonstrates that this constraint is met, limiting total potential reward and penalty incentive dollars to $7,001,961.

Q. Please summarize your direct testimony.

A. Tampa Electric has complied with the Commission's directions, philosophy, and methodology in its determination of the GPIF. The GPIF is determined by the following formula for calculating Generating Performance Incentive Points (GPIP).

$$
\begin{aligned}
GPIP = (&0.0482\ EAP_{PK1} + 0.0153\ EAP_{PK2} \\
&+ 0.1601\ EAP_{BAY1} + 0.0745\ EAP_{BAY2} \\
&+ 0.0129\ EAP_{BB4} + 0.2374\ HRP_{PK2} \\
&+ 0.1083\ HRP_{BAY1} + 0.1231\ HRP_{BAY2} \\
&+ 0.1368\ HRP_{BB4} + 0.0834\ HRP_{PK1})
\end{aligned}
$$

Where:

GPIP = Generating Performance Incentive Points

EAP = Equivalent Availability Points awarded/deducted for Polk Units 1 and 2, Bayside Units 1 and 2, and Big Bend Unit 4.

HRP = Average Net Heat Rate Points awarded/deducted for Polk Units 1 and 2, Bayside Units 1 and 2, and Big Bend Unit 4.

Q. Have you prepared a document summarizing the GPIF targets for the January through December 2021 period?

A. Yes. Document No. 2 entitled “Summary of GPIF Targets” provides the availability and heat rate targets for each unit.

Q. Does this conclude your direct testimony?

A. Yes, it does.

(Transcript continues in sequence in Volume 2.)

CERTIFICATE OF REPORTER

STATE OF FLORIDA)
COUNTY OF LEON)

I, DEBRA KRICK, Court Reporter, do hereby certify that the foregoing proceeding was heard at the time and place herein stated.

IT IS FURTHER CERTIFIED that I stenographically reported the said proceedings; that the same has been transcribed under my direct supervision; and that this transcript constitutes a true transcription of my notes of said proceedings.

I FURTHER CERTIFY that I am not a relative, employee, attorney or counsel of any of the parties, nor am I a relative or employee of any of the parties' attorney or counsel connected with the action, nor am I financially interested in the action.

DATED this 4th day of November, 2020.

Debbie R Krick

DEBRA R. KRICK
NOTARY PUBLIC
COMMISSION #HH31926
EXPIRES AUGUST 13, 2024

BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

In the Matter of:

DOCKET NO. 20200001-EI

FUEL AND PURCHASED POWER
COST RECOVERY CLAUSE WITH
GENERATING PERFORMANCE
INCENTIVE FACTOR.
_____________________________/

VOLUME 2
PAGES 249 through 452

PROCEEDINGS: HEARING

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

DATE: Tuesday, November 3, 2020

TIME: Commenced: 10:20 a.m.
Concluded: 5:12 p.m.

PLACE: Betty Easley Conference Center
Room 148
4075 Esplanade Way
Tallahassee, Florida

REPORTED BY: DEBRA R. KRICK
Court Reporter

APPEARANCES: (As heretofore noted.)

PREMIER REPORTING
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I N D E X

WITNESSES

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EXHIBITS

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P R O C E E D I N G S

(Transcript follows in sequence from Volume 1.)

(Whereupon, prefiled direct testimony of Benjamin F. Smith was inserted.)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

BENJAMIN F. SMITH II

Q. Please state your name, address, occupation, and employer.

A. My name is Benjamin F. Smith II. My business address is 702 North Franklin Street, Tampa, Florida 33602. I am employed by Tampa Electric Company ("Tampa Electric" or "company") as Manager, Gas and Power Origination within the Fuel and Planning Services Department.

Q. Please provide a brief outline of your educational background and business experience.

A. I received a Bachelor of Science degree in Electric Engineering in 1991 from the University of South Florida in Tampa, Florida, and a Master of Business Administration degree in 2015 from Saint Leo University in Saint Leo, Florida. I am also a registered Professional Engineer within the State of Florida and a Certified Energy Manager through the Association of Energy Engineers. I joined Tampa Electric in 1990 as a cooperative education student.

During my years with the company, I have worked in the areas of transmission engineering, distribution engineering, resource planning, retail marketing, and wholesale power marketing. I am currently the Manager, Gas and Power Origination within the Fuel and Planning Services Department. My responsibilities are to evaluate short and long-term power purchase and sale opportunities within the wholesale power market, assist in wholesale power and gas transportation origination and contract structures, and assist in combustion by-product contract administration and market opportunities. In this capacity, I interact with wholesale power market participants such as utilities, municipalities, electric cooperatives, power marketers, other wholesale developers and independent power producers, as well as with natural gas pipeline owners and transporters.

Q. Have you previously testified before the Florida Public Service Commission ("Commission")?

A. Yes. I have submitted written testimony in the annual fuel docket since 2003, and I have testified before this Commission in Docket Nos. 20030001-EI, 20040001-EI, and 20080001-EI regarding the appropriateness and prudence of Tampa Electric's wholesale purchases and sales.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to provide a description of Tampa Electric's purchased power agreements that the company has entered into and for which it is seeking cost recovery through the Fuel and Purchased Power Cost Recovery Clause ("fuel clause") and the Capacity Cost Recovery Clause. I also describe Tampa Electric's purchased power strategy for mitigating price and supply-side risk, while providing customers with a reliable supply of economically priced purchased power.

Q. Please describe the efforts Tampa Electric makes to ensure that its wholesale purchases and sales activities are conducted in a reasonable and prudent manner.

A. Tampa Electric evaluates potential purchase and sale opportunities by analyzing the expected available amounts of generation and power required to meet the projected demand and energy of its customers. Purchases are made to achieve reserve margin requirements, meet customers' demand and energy needs, meet operating reserve requirements, supplement generation during unit outages, and for economical purposes. When Tampa Electric considers making a power purchase, the company diligently searches for available supplies of wholesale capacity or energy from creditworthy counterparties. The objective is to secure reliable quantities of purchased power for customers at the best possible price.

Conversely, when there is a sales opportunity, the company offers profitable wholesale capacity or energy products to creditworthy counterparties. The company has wholesale power purchase and sale transaction enabling agreements with numerous counterparties. This process helps to ensure that the company's wholesale purchase and sale activities are conducted in a reasonable and prudent manner.

Q. Has Tampa Electric reasonably managed its wholesale power purchases and sales for the benefit of its retail customers?

A. Yes, it has. Tampa Electric has fully complied with, and continues to fully comply with, the Commission's March 11, 1997 Order, No. PSC-1997-0262-FOF-EI, issued in Docket No. 19970001-EI, which governs the treatment of separated and non-separated wholesale sales. The company's wholesale purchase and sale activities and transactions are also reviewed and audited on a recurring basis by the Commission.

In addition, Tampa Electric actively manages its wholesale purchases and sales with the goal of capitalizing on opportunities to reduce customer costs and improve reliability. The company monitors its contractual rights with purchased power suppliers, as well as with entities to which wholesale power is sold, to detect and prevent any breach of the company's contractual rights. Tampa Electric continually strives to improve its knowledge of wholesale power markets and available opportunities within the marketplace. The company uses this knowledge to minimize the costs of purchased power and to maximize the savings the company provides retail customers by making wholesale sales when excess power is available on Tampa Electric's system and market conditions allow.

Q. Please describe Tampa Electric's 2020 wholesale power purchases.

A. Tampa Electric assessed the wholesale power market and entered into short- and long-term purchases based on price and availability of supply. Approximately nine percent of the company's expected needs for 2020 will be met using purchased power. This includes economy energy purchases, reliability purchases, as-available purchases from qualifying facilities, and forward purchases from Duke Energy Florida (DEF), the Florida Municipal Power Agency (FMPA), Florida Power & Light (FPL), and the Orlando Utilities Commission (OUC).

Tampa Electric secured two non-firm and five firm purchases in 2020. The company secured the non-firm purchases during the first quarter of 2020, with DEF and FPL. The DEF non-firm purchase is an extension of Tampa Electric’s previous contract to purchase non-firm energy from DEF for the period February 2019 through February 2020. The extension covers the period March 2020 through February 2021, and the energy volume available under the contract remains at a maximum of 515 MW per hour. The DEF extension does not have a must-take obligation. The extension provides Tampa Electric the flexibility to schedule the energy when beneficial to customers. The FPL non-firm purchase is a must-take for 150-300 MW, depending on the month and hour, and is for the term April through November 2020. The must-take hours are hours ending 7 through 24 (i.e., HE 7-24), May through October, and HE 7-23, April and November. Combined, the two non-firm transactions are estimated to result in $5.25 million in savings to customers. As authorized by the Commission in Order No. 2017-0456-S-EI, issued on November 27, 2017, these savings flow through the company's optimization mechanism which are described in the Fuel and Purchased Power Cost Recovery and Capacity Cost Recovery docket annual true-up filing along with mechanism saving sharing reporting and accompanying testimony of Tampa Electric witness John C. Heisey.

The five firm purchase agreements by dates of occurrence are:

- December 2019 through February 2020: 112 MW from FMPA
- July 2020 through September 2020: 74 MW from FMPA
- December 2020 through February 2021: 150 MW from FMPA, 160 MW from FPL, and 100 MW from OUC

The company secured these purchase agreements during the fourth quarter of 2019. All of the agreements are peaking call options, and a portion of the agreements have been entered into for reliability purposes. The 112 MW from FMPA and 95 MW of the 150 MW from FMPA are to meet the company's 20 percent firm reserve margin criteria during the winter 2020 and winter 2021 periods, respectively. The balance of the purchase agreements represent economic purchases and support the Big Bend Modernization Project by allowing an early re-powering outage on Big Bend Unit 1, which is the unit being modernized. The early re-powering outage provides the Modernization team with more flexibility to schedule work on the unit, given the Modernization's two new combustion turbines are expected to be in-service by the fall of 2021. The economic portion of these purchases (i.e., 74 MW FMPA, 160 MW FPL, 100 MW OUC, and 55 MW of the FMPA 150 MW) is estimated to provide a combined $445.9 thousand in savings to customers, $325.6 thousand of which are expected to be generated in 2020. As mentioned earlier, these savings flow through the company's optimization mechanism and benefit customers in accordance with the methodology approved by the Commission.

Tampa Electric has not secured other forward purchases for 2020 at this time. However, the company constantly searches for economic purchase opportunities that benefit customers. As other purchase opportunities materialize, the company evaluates each product to determine the viability of making it part of the supply portfolio Tampa Electric uses to serve customers.

Q. Does Tampa Electric anticipate entering into new wholesale power purchases for 2021 and beyond?

A. Other than the previously mentioned DEF extension and firm purchases for December 2020 through February 2021, Tampa Electric has made no other forward purchases to date. However, the company will continue to identify and evaluate purchase opportunities for 2021 and beyond that bring value to customers. Currently, Tampa Electric expects purchased power to meet approximately two percent of its 2021 energy needs.

Q. How does Tampa Electric mitigate the risk of disruptions to its purchased power supplies during major weather-related events, such as hurricanes?

A. During hurricane season, Tampa Electric continues to utilize a purchased power risk management strategy to minimize potential power supply disruptions. The strategy includes monitoring storm activity; evaluating the impact of storms on existing forward purchases and the rest of the wholesale power market; communicating with suppliers about their storm preparations and potential impacts to existing transactions, purchasing additional power on the forward market, if appropriate, for reliability and economics; evaluating transmission availability and the geographic location of electric resources; reviewing sellers' fuel sources and dual-fuel capabilities; and focusing on fuel-diversified purchases. Absent the threat of a hurricane, and for all other months of the year, the company evaluates economic combinations of short- and long-term purchase opportunities in the marketplace.

Q. Please describe Tampa Electric's wholesale energy sales for 2020 and 2021.

A. Tampa Electric entered into various non-separated (e.g., next-hour and next-day sales) wholesale sales in 2020, and the company anticipates making additional non-separated sales during the balance of 2020 and 2021. The gains from these sales are shared between Tampa Electric and its customers in accordance with the company's optimization mechanism.

Q. Please summarize your direct testimony.

A. Tampa Electric monitors and assesses the wholesale power market to identify and take advantage of opportunities in the marketplace, and these efforts benefit the company's customers. Tampa Electric's energy supply strategy includes self-generation and short- and long-term power purchases. The company purchases in both physical forward and spot wholesale power markets to provide customers with a reliable supply at the lowest possible cost. In addition to the cost benefits, this purchased power approach employs a diversified physical power supply strategy that enhances reliability. The company also enters into wholesale sales that benefit customers when market conditions allow.

Q. Does this conclude your direct testimony?

A. Yes, it does.

(Whereupon, prefiled direct testimony of John C. Heisey was inserted.)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

JOHN C. HEISEY

Q. Please state your name, address, occupation and employer.

A. My name is John C. Heisey. My business address is 702 N. Franklin Street, Tampa, Florida 33602. I am employed by Tampa Electric Company ("Tampa Electric" or "company") as Manager, Gas and Power Trading.

Q. Please provide a brief outline of your educational background and business experience.

A. I graduated from Pennsylvania State University with a Bachelor of Science in Business Logistics. I have over 25 years of power and natural gas trading experience, including employment at TECO Energy Source, FPL Energy Services, El Paso Energy, and International Paper. Prior to joining Tampa Electric, I was Vice President of Asset Trading for the Entegra Power Group LLC ("Entegra") where I was responsible for Entegra's energy trading activities. Entegra managed a large quantity of merchant capacity in bilateral and organized markets. I joined

Tampa Electric in September 2016 as the Manager of Gas and Power Trading and currently hold that position. I am responsible for all natural gas and power trading activities and work closely with the company's unit commitment to provide low cost, reliable power to our customers. In addition, I am responsible for portfolio optimization and all aspects of the Optimization Mechanism.

Q. Please state the purpose of your testimony.

A. The purpose of my testimony is to present, for the Commission's review, the 2019 results of Tampa Electric's activities under the Optimization Mechanism, as authorized by FPSC Order No. PSC-2017-0456-S-EI, issued in Docket No. 20160160-EI on November 27, 2017.

Q. Do you wish to sponsor an exhibit in support of your testimony?

A. Yes. Exhibit No. JCH-1, entitled Optimization Mechanism Results, was prepared under my direction and supervision. My exhibit shows the gains for each type of activity included in the Optimization Mechanism and the sharing of gains between customers and the company.

Q. Please provide an overview of the Optimization Mechanism.

A. The Optimization Mechanism is designed to create additional value for Tampa Electric's customers while also providing an incentive to the company if certain customer-value thresholds are achieved. The Optimization Mechanism includes gains from wholesale power sales and savings from wholesale power purchases, as well as gains from other forms of asset optimization.

Q. Please describe Tampa Electric's Optimization Mechanism submitted in Docket No. 20160160-EI and approved by Order No. PSC-2017-0456-S-EI.

A. Effective January 1, 2018, for the four-year period from 2018 through 2021, gains on all optimization mechanism activities, including short-term wholesale sales, short-term wholesale purchases, and all forms of asset optimization undertaken each year will be shared between shareholders and customers. The sharing thresholds are (a) for the first $4.5 million per year, 100 percent of gains to customers; (b) for gains greater than $4.5 million per year and less than $8.0 million per year, split 60 percent to shareholders and 40 percent to customers; and (c) for gains greater than $8.0 million per year, 50-50 sharing between shareholders and customers.

Optimization Mechanism Transactions

Q. Please provide the details of Tampa Electric's short-term wholesale sales under the Optimization Mechanism for 2019.

A. Optimization Mechanism gains from wholesale sales were $1,498,686 or 23 percent of optimization gains for 2019. The monthly detail is shown in my exhibit in the schedule "Wholesale Sales-Table 3."

Q. Please provide the details of Tampa Electric's short-term wholesale purchases under the Optimization Mechanism for 2019.

A. Optimization Mechanism gains from wholesale purchases were $4,428,298 or 68 percent of optimization gains for 2019. The monthly detail can be found in my exhibit on the schedule labeled "Wholesale Purchases-Table 4."

Q. Please describe Tampa Electric's asset optimization activities and the gains from those transactions under the Optimization Mechanism for 2019.

A. Optimization Mechanism gains from asset optimization activities were $541,049 or 9 percent of optimization gains for 2019. The gains from asset optimization activities are shown in my exhibit at "Asset Optimization Detail-Table 5."

A description of Tampa Electric's 2019 asset optimization activities is provided below.

- Gas storage utilization - release contracted storage space or sell stored gas during non-critical demand seasons;
- Delivered solid fuel and or transportation capacity sales using existing transport - sell coal and coal transportation, using Tampa Electric's existing coal and transportation capacity during periods when it is not needed to serve Tampa Electric's native electric load;
- Asset Management Agreement ("AMA") - outsource optimization functions to a third party through assignment of power, transportation and/or storage rights in exchange for a premium to be paid to Tampa Electric.

Q. Please summarize the activities and results of the Optimization Mechanism for 2019.

A. Tampa Electric participated in the following Optimization Mechanism activities in 2019: wholesale power purchases and sales, gas storage utilization, delivered solid fuel sales, and natural gas storage AMAs. The optimization gains for 2019 were $6,468,033 which exceeded the $4,500,000 threshold by $1,968,033 as shown in my exhibit on schedule "Total Gains Threshold Schedule-Table 1." Customer benefits were $5,287,213, and company benefits were $1,180,820 in 2019.

Q. Did Tampa Electric incur incremental Optimization Mechanism costs during 2019?

A. Tampa Electric incurred incremental Optimization Mechanism personnel costs to establish processes and manage these new activities. However, the company agreed that it would not seek recovery of these costs through the Optimization Mechanism if it was approved and therefore has not separately tracked the costs.

Q. Overall, were Tampa Electric's activities under the Optimization Mechanism successful in 2019?

A. Yes, Tampa Electric produced customer gains of $5,287,213 in the second year of Optimization Mechanism activity.

The company continues to focus on improvements in processes, reporting, and optimization strategies.

The southeast United States experienced mild winter weather. Thus, most of the Optimization Mechanism gains in 2019 were generated in the spring, summer, and fall. Economic wholesale power purchases were the largest contributor of gains in the summer. Additional gains resulted from wholesale power purchases made in the spring during company planned maintenance. Wholesale power sales gains were driven by above normal temperatures in May, June, and October. Natural gas storage AMA gains were consistent throughout the year. Lastly, coal sales contributed solid fuel gains in the first half of the year.

Q. Does this conclude your testimony?

A. Yes, it does.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

JOHN C. HEISEY

Q. Please state your name, address, occupation, and employer.

A. My name is John C. Heisey. My business address is 702 N. Franklin Street, Tampa, Florida 33602. I am employed by Tampa Electric Company ("Tampa Electric" or "company") as Manager, Gas and Power Trading.

Q. Have you previously filed testimony in Docket No. 20200001-EI?

A. Yes, I submitted direct testimony on March 2, 2020.

Q. Has your job description, education, or professional experience changed since your most recent testimony?

A. No, it has not.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to discuss Tampa Electric's fuel mix, fuel price forecasts, potential impacts to fuel prices, and the company's fuel procurement strategies.

Fuel Mix and Procurement Strategies

Q. What fuels do Tampa Electric's generating stations use?

A. Tampa Electric's fuel mix includes natural gas, solar, coal, and, as a backup fuel, oil. Big Bend Unit 2 can operate on natural gas, and Big Bend Units 3 and 4 can operate on coal or natural gas. Polk Unit 1 can operate on natural gas or a blend of petroleum coke and coal. Currently, the company is operating Big Bend Unit 2, Big Bend Unit 3 and Polk Unit 1 on natural gas and Big Bend Unit 4 on coal. Polk Unit 2 combined cycle uses natural gas as a primary fuel and oil as a secondary fuel; and Bayside Station combined cycle units and the company's collection of peakers (*i.e.,* aero-derivative combustion turbines) all utilize natural gas. Since it serves as a backup fuel, oil consumption is primarily for testing, and oil is a negligible percentage of system generation. During 2020, continued low natural gas prices equate to lower fuel prices for customers. Based upon the 2020 actual-estimate projections, the company expects 2020 total system generation, excluding purchased power, to be

89 percent natural gas, 7 percent solar, and 4 percent coal.

Likewise, in 2021, natural gas-fired and solar generation are expected to be 87 percent and 8 percent of total generation, respectively, with coal-fired generation making up 5 percent of total generation.

Q. Please describe Tampa Electric’s fuel supply procurement strategy.

A. Tampa Electric emphasizes flexibility and options in its fuel procurement strategy for all its fuel needs. The company strives to maintain many credit worthy and viable suppliers. Similarly, the company endeavors to maintain multiple delivery path options. Tampa Electric also attempts to diversify the locations from which its supply is sourced. Having a greater number of fuel supply and delivery options provides increased reliability and flexibility to pursue lower cost options for Tampa Electric customers.

Natural Gas Supply Strategy

Q. How does Tampa Electric’s natural gas procurement and transportation strategy achieve competitive natural gas purchase prices for long- and short-term deliveries?

A. Tampa Electric uses a portfolio approach to natural gas procurement. This approach consists of a blend of pre-arranged base, intermediate, and swing natural gas supply contracts complemented with shorter term spot and seasonal purchases. The contracts have various time lengths to help secure needed supply at competitive prices and maintain the ability to take advantage of favorable natural gas price movements. Tampa Electric purchases its physical natural gas supply from creditworthy counterparties, enhancing the liquidity and diversification of its natural gas supply portfolio. The natural gas prices are based on monthly and daily price indices, further increasing pricing diversification.

Tampa Electric diversifies its pipeline transportation assets, including receipt points. The company also utilizes pipeline and storage services to enhance access to natural gas supply during hurricanes or other events that constrain supply. Such actions improve the reliability and cost-effectiveness of the physical delivery of natural gas to the company's power plants. Furthermore, Tampa Electric strives daily to obtain reliable supplies of natural gas at favorable prices in order to mitigate costs to its customers.

Q. Please describe Tampa Electric's diversified natural gas transportation agreements.

A. Tampa Electric currently receives natural gas directly via the Florida Gas Transmission ("FGT") and Gulfstream Natural Gas System, LLC ("Gulfstream") pipelines. Tampa Electric has added the ability to receive a portion of its gas via the recently constructed Sabal Trail Transmission ("Sabal Trail") gas pipeline (via Gulfstream backhaul). The ability to deliver natural gas from three pipelines increases the fuel delivery reliability for Bayside Power Station, which is composed of two large natural gas combined-cycle units and four aero-derivative combustion turbines. Natural gas can also be delivered to Big Bend Station from Gulfstream and Sabal Trail to support the station's steam generating units and aero-derivative combustion turbine. Polk Station receives natural gas from FGT to support natural gas consumption in Polk Unit 1 and Polk Unit 2. The addition of Sabal Trail to the company's delivery options enhances reliability, supply, price, and location diversity.

Q. Are there any significant changes to Tampa Electric's expected natural gas usage?

A. Tampa Electric’s natural gas usage is expected to remain stable in 2021. The strategy of burning economical natural gas in dual-fueled units continues to provide lower overall costs to customers.

Q. What actions does Tampa Electric take to enhance the reliability of its natural gas supply?

A. Tampa Electric maintains natural gas storage capacity with Bay Gas Storage near Mobile, Alabama, and Southern Pines Energy Center in Eastern Mississippi to provide operational flexibility and reliability of natural gas supply. The company reserves 2,000,000 MMBtu of long-term storage capacity in these two locations.

In addition to storage, Tampa Electric maintains diversified natural gas supply receipt points in FGT Zones 1, 2, and 3. Diverse receipt points reduce the company’s vulnerability to hurricane impacts and provide access to potentially lower priced gas supply.

Tampa Electric also reserves capacity on the Southeast Supply Header (“SESH”), Gulf South pipeline (“Gulf

South") and Transco's Mobile Bay Lateral ("Transco"). SESH, Gulf South and Transco connect the receipt points of FGT, Gulfstream and other Mobile Bay area pipelines with natural gas supply in the mid-continent and northeast. Mid-continent and northeast natural gas production, specifically shale production, has grown and continues to increase. Thus, SESH, Gulf South and Transco capacity give Tampa Electric access to secure, competitively priced onshore gas supply for a portion of its portfolio.

Q. Has Tampa Electric acquired additional natural gas transportation for 2020 and 2021 due to greater use of natural gas?

A. Yes, with the continued low price of natural gas and the company's growing demand for natural gas for electric generation purposes, the company acquires daily, seasonal, and longer-term pipeline capacity to support the company's portfolio of gas-fired generation assets. In 2020, Tampa Electric acquired additional pipeline capacity on Gulf South, which is similar to existing upstream capacity on SESH and Transco. This capacity provides additional diversification of pipelines and gas supply receipt points, access to lower cost onshore supply basins, and minimizes the risk of declining Mobile Bay offshore production. In 2021, Tampa Electric acquired additional Sabal Trail capacity which will enhance reliability, supply, price, and location diversity.

Coal Supply Strategy

Q. Please describe Tampa Electric's solid fuel usage and procurement strategy.

A. Like its natural gas strategy, Tampa Electric uses a portfolio approach to coal procurement. The steam turbine units at Big Bend Station are designed to burn high-sulfur Illinois Basin coal and are fully scrubbed for sulfur dioxide and nitrogen oxides, and the units have been upgraded to operate on natural gas. Polk Unit 1 can burn a blend of petroleum coke and low sulfur coal, or natural gas. Each plant has varying operational and environmental restrictions and requires solid fuel with custom quality characteristics such as ash content, fusion temperature, sulfur content, heat content, and chlorine content.

Coal is not a homogenous product. The fuel's chemistry and contents vary based on many factors, including geography. The variability of the product dictates Tampa Electric select its fuel based on multiple parameters.

Those parameters include unique coal quality characteristics, price, availability, deliverability, and credit worthiness of the supplier.

To minimize costs, maintain operational flexibility, and ensure reliable supply, Tampa Electric typically maintains a portfolio of bilateral coal supply contracts with varying term lengths. Tampa Electric monitors the market to obtain the most favorable prices from sources that meet the needs of the generation stations. The use of daily and weekly publications, independent research analyses from industry experts, discussions with suppliers, and coal solicitations aid the company in monitoring the coal market. This market intelligence also helps shape the company’s coal procurement strategy to reflect short- and long-term market conditions. Tampa Electric’s strategy provides a stable supply of reliable fuel sources. In addition, this strategy allows the company the flexibility to take advantage of favorable spot market opportunities and address operational needs.

Q. Please summarize how Tampa Electric will manage its solid fuel supply contracts through 2021.

A. Since the company is projected to use less coal and more natural gas in 2021 compared to previous years, Tampa Electric will supply the Big Bend and Polk Stations with solid fuel through a combination of existing inventory, short-term contracts and, as necessary, spot purchases in support of the most economic commitment and dispatch for the generation fleet. The short-term and spot purchases allow the company to adjust supply to reflect changing coal quality and quantity needs, operational changes, and pricing opportunities.

Coal Transportation

Q. Please describe Tampa Electric's solid fuel transportation arrangements.

A. Tampa Electric can receive coal at its Big Bend Station via waterborne or rail delivery. Once delivered to Big Bend Station, solid fuel is consumed onsite, or blended and trucked to Polk Station for consumption in Polk Unit 1. As a result of declining solid fuel burns over the last few years, Tampa Electric has transitioned to purchasing delivered coal, where waterborne coal supply and transportation are arranged by the supplier. The complex logistics of procuring quality-specific coal for multiple units is no longer necessary at Tampa Electric as fewer units are burning solid fuel and the projected consumption is declining. Procuring delivered coal continues to provide customers with competitive coal prices through a simplified process. Commodity and transportation of coal by rail is still being arranged separately, as necessary.

Q. Why does the company maintain multiple coal transportation options in its portfolio?

A. Bimodal solid fuel transportation to Big Bend Station affords the company and its customers various benefits. Those benefits include 1) access to more potential coal suppliers, which results in a more competitively priced, and diverse, delivered coal portfolio; 2) the opportunity to switch to either water or rail in the event of a transportation breakdown or interruption on the other mode; and 3) competition among transporters for future solid fuel transportation contracts.

Q. Will Tampa Electric continue to receive coal deliveries via rail in 2020 and 2021?

A. Yes. Tampa Electric expects to receive coal for use at Big Bend Station through the Big Bend rail facility during 2020 and is evaluating how much coal to receive by rail in 2021.

Q. Please describe Tampa Electric's expectations regarding waterborne coal deliveries.

A. Tampa Electric expects to receive solid fuel supply from waterborne deliveries to its unloading facilities at Big Bend Station. These deliveries come via the Mississippi River System through United Bulk Terminal or from foreign sources. The ultimate supply source is dependent upon quality, operational needs, and lowest overall delivered cost.

Q. Do you have any other updates to provide regarding Tampa Electric's solid fuel transportation portfolio?

A. The continued trend of an abundant volume of natural gas available at historically low prices results in Tampa Electric's continued use of natural gas in the dual-fueled Big Bend and Polk units. In addition, the company's strategy of utilizing short-term and spot delivered solid fuel purchases allows Tampa Electric to reduce its solid fuel deliveries going forward, which aligns well with the economical use of natural gas. As a result, Tampa Electric will contract for fewer tons of solid fuel supply and transportation in the remainder of 2020 and 2021 than in previous years.

Q. Please describe any other significant factors that Tampa Electric considered in developing its 2021 solid fuel supply portfolio.

A. Tampa Electric continues to place emphasis on flexibility in its solid fuel supply portfolio. The company recognizes that several factors may impact the annual consumption of solid fuel. These factors include the relative price of delivered solid fuel compared to the delivered natural gas and wholesale power markets. Thus, the actual quantity of solid fuel burned may vary significantly each year. In developing its solid fuel portfolio, Tampa Electric strives to balance the need to have reliable solid fuel commodity supplies and transportation while mitigating the potential for significant shortfall penalties if the commodity or transportation is not needed.

Q. Has Tampa Electric reasonably managed its fuel procurement practices for the benefit of its retail customers?

A. Yes, Tampa Electric diligently manages its mix of long-term, intermediate, and short-term purchases of fuel in a manner designed to reduce overall fuel costs while maintaining electric service reliability. The company's fuel activities and transactions are reviewed and audited on a recurring basis by the Commission. In addition, the company monitors its rights under contracts with fuel suppliers to detect and prevent any breach of those rights. Tampa Electric continually strives to improve its knowledge of fuel markets and to take advantage of opportunities to minimize the costs of fuel.

Q. Have there been other changes in the management of Tampa Electric's fuel supply portfolio?

A. Yes, as part of Tampa Electric's 2017 Amended and Restated Stipulation and Settlement Agreement approved by Commission Order No. PSC-2017-0456-S-EI, issued on November 27, 2017 in Docket No. 20170210-EI, Tampa Electric has been operating under an Asset Optimization Mechanism since January 1, 2018. This Optimization Mechanism encourages Tampa Electric to market temporarily unused fuel supply assets to capture cost mitigation benefits for customers. These benefits have come through economic power purchases, economic power sales, resale of unneeded fuel supply, an asset management agreement for natural gas storage, and utilization of natural gas and solid fuel storage and transportation assets.

Projected 2021 Fuel Prices

Q. How does Tampa Electric project fuel prices?

A. Tampa Electric reviews fuel price forecasts from sources widely used in the industry, including the New York Mercantile Exchange ("NYMEX"), PIRA Energy, the Energy Information Administration, and other energy market information sources. Future prices for energy commodities as traded on NYMEX, averaged over five consecutive business days in August2020, form the basis of the natural gas and No. 2 oil market commodity price forecasts. The price projections for these two commodities are then adjusted to incorporate expected transportation costs and location differences.

Coal prices and coal transportation prices are projected using contracted pricing and information from industry recognized consultants and published indices, such as IHS Markit and *Coal Daily*. Also, the price projections are specific to the particular quality and mined location of coal utilized by Tampa Electric's Big Bend Station and Polk Unit 1. Final as-burned prices are derived using expected commodity prices and associated transportation costs.

Q. How do the 2021 projected fuel prices compare to the fuel prices projected for 2020 in the company’s mid-course correction filing?

A. Large quantities of domestic shale-related production are keeping natural gas prices low. However, though demand impacts from the COVID-19 pandemic further reduced 2020 natural gas prices to historically low levels, a rebound is expected in 2021 as demand is expected to outpace supply. Additionally, there is a significant amount of uncertainty associated with the natural gas prices for 2021 as a result of the pandemic. The commodity price for natural gas during 2021 is projected to be higher ($2.88 per MMBtu) than the 2020 price ($2.05 per MMBtu) projected in the company’s mid-course correction fuel filing. The 2021 coal commodity price projection is slightly higher ($41.03 per ton) than the price projected for 2020 ($39.52 per ton) during preparation of the 2020 mid-course correction fuel clause factors. International demand for coal is elevating coal prices despite minimal domestic demand.

Q. Does this conclude your direct testimony?

A. Yes, it does.

(Whereupon, prefiled direct testimony of Debra M. Dobiac was inserted.)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

COMMISSION STAFF

DIRECT TESTIMONY OF DEBRA DOBIAC

DOCKET NO. 20200001-EI

SEPTEMBER 16, 2020

Q. Please state your name and business address.

A. My name is Debra M. Dobiac. My business address is 2540 Shumard Oak Boulevard, Tallahassee, Florida, 32399.

Q. By whom are you presently employed and in what capacity?

A. I am employed by the Florida Public Service Commission (FPSC or Commission) as a Public Utility Analyst in the Office of Auditing and Performance Analysis. I have been employed by the Commission since January 2008.

Q. Briefly review your educational and professional background.

A. I graduated with honors from Lakeland College in 1993 and have a Bachelor of Arts degree in accounting. Prior to my work at the Commission, I worked for six years in internal auditing at the Kohler Company and First American Title Insurance Company. I also have approximately 12 years of experience as an accounting manager and controller.

Q. Please describe your current responsibilities.

A. My responsibilities consist of planning and conducting utility audits of manual and automated accounting systems for historical and forecasted data.

Q. Have you previously presented testimony before this Commission?

A. Yes. I testified in the Aqua Utilities Florida, Inc. Rate Case, Docket No. 20080121-WS, the Water Management Services, Inc. Rate Case, Docket No. 20110200-WU, and the Utilities, Inc. of Florida Rate Case, Docket No. 20160101-WS. I also provided testimony for the Water Management Services, Inc. Rate Case, Docket No. 20100104-WU, the Gulf Power Company Rate Cases, Docket Nos. 20110138-EI and 20130140-EI, the Fuel and Purchased Power Recovery Clause (Hedging Activities) for Gulf Power Company, Docket Nos. 20130001-EI, 20140001-EI, and 20190001-EI, the Fuel and Purchased Power Recovery Clause (Hedging Activities) for Florida Power & Light Company, Docket No. 20180001-EI, Florida Public Utilities Company's Limited Proceeding to recover incremental Storm Restoration Costs, Docket No. 20180061-EI, the Gulf Power Company Limited Proceeding to recover incremental Storm Restoration Costs, Docket No. 20190038-EI, and the Florida Public Utilities Company's Petition for a Limited Proceeding to recover incremental Storm Restoration Costs, Capital Costs, Revenue Reduction for Permanently Lost Customers, and Regulatory Assets Related to Hurricane Michael in Docket No. 20190156-EI.

Q. What is the purpose of your testimony today?

A. The purpose of my testimony is to sponsor the staff auditor's report of Gulf Power Company (Gulf or Utility) which addresses the Utility's filing in Docket No. 20200001-EI, Fuel and Purchased Power Cost Recovery Clause, for costs associated with its hedging activities. We issued an auditor's report in this docket for the hedging activities on September 1, 2020. This report is filed with my testimony and is identified as Exhibit DMD-1.

Q. Was this audit prepared by you or under your direction?

A. Yes, it was prepared by me.

Q. Please describe the work you performed in this audit.

A. I have separated the audit work into several categories.

<u>Accounting Treatment</u>

We obtained Gulf's supporting detail of the hedging settlements for the twelve months ended July 31, 2020. The support documentation was traced to the general ledger transaction detail. We verified that the hedging settlements are in compliance with the Risk Management

Plan and verified that the accounting treatment for hedging transactions and transactions costs is consistent with Commission orders relating to hedging activities. The Utility did not enter into any new contracts between August 1, 2019 and July 31, 2020. Gulf's hedging program was completed in the first quarter of 2020. No exceptions were noted.

Gains and Losses

We traced the monthly balances of all hedging transactions from Gulf's Hedging Information Reports to its settlement report and its general ledger for the period August 1, 2019 to July 31, 2020. We reviewed existing tolling agreements whereby the Utility's natural gas is provided to generators under purchased power agreements. We recalculated the gains and losses, traced the price to the settlement statement details, and compared the price to the gas futures rates published by the New York Mercantile Exchange (NYMEX) Henry Hub Gas futures contract rates. We compared these recalculated gains and losses with Gulf's journal entries for realized gains and losses. No exceptions were noted.

Hedged Volume and Limits

We reviewed the quantity limits and authorizations. We also obtained GPC's analysis of the monthly percent of natural gas hedged in relation to natural gas burned for the twelve months ended July 31, 2020, and compared them with the Utility's 2016 Risk Management Plan. No exceptions were noted.

Separation of Duties

We reviewed the Utility's procedures for separating duties related to hedging activities. We noted that as of January 1, 2019, all hedges outstanding were transferred to NextEra/FPL and they oversee the settling of the remaining hedges. There were no internal and external audits specifically performed on the separation of duties related to hedging activities. No exceptions were noted.

Q. Please review the audit findings in this report.

A. There were no findings in this audit.

Q. Does that conclude your testimony?

A. Yes.

CHAIRMAN CLARK: Exhibits.
MS. BROWNLESS: Yes, sir.
Staff has compiled a stipulated Composite Exhibit List, which includes the prefiled exhibits attached to the witness' testimony as well as Staff's Exhibits 48 through 52. The list has been provided to the parties, to the Commissioners and the court reporter.
At this time, Staff requests that the Comprehensive Exhibit List be marked for identification purposes as Exhibit No. 1, and that the other exhibits be marked for identification as set forth in the Comprehensive Exhibit List.
CHAIRMAN CLARK: The orders are so marked.
(Whereupon, Exhibit Nos. 1 - 52 were marked for identification.)
MS. BROWNLESS: Thank you.
We would ask that the Comprehensive Exhibit List, marked as Exhibit No. 1, be entered into the record.
CHAIRMAN CLARK: Exhibit No. 1 is entered.
(Whereupon, Exhibit No. 1 was received into evidence.)
MS. BROWNLESS: At this time, we would request that Stipulated Staff Exhibits Nos. 48 through 52

be entered into the record.

CHAIRMAN CLARK: So ordered.

(Whereupon, Exhibit Nos. 48 - 52 were received into evidence.)

MS. BROWNLESS: And we would also ask that the exhibits that were agreed to by the parties, Exhibits Nos. 8 through 47, be entered into the record.

CHAIRMAN CLARK: All right. Is there any objection to 8 through 47? Any objection to those exhibits?

Seeing none, so ordered.

(Whereupon, Exhibit Nos. 8 - 47 were received into evidence.)

COMMISSIONER BROWN: Mr. Chairman, before we move into opening statements, I did have a question regarding one of the preliminary matters that Ms. Brownless mentioned, if this would be an appropriate time.

CHAIRMAN CLARK: Yes, Commissioner Brown.

COMMISSIONER BROWN: Thank you.

Ms. Brownless, you said that yesterday Duke filed an appeal and motion to stay the Commission's order adopting Judge Stevenson's Recommended Order regarding Bartow Unit 4, replacement costs. How --

and then you also stated that the motion will be dealt with at the Commission's December 1st agenda conference.

How does that affect our proceedings today? And if so, what issues are affected, and what are the limitations regarding -- surrounding this motion?

MS. BROWNLESS: Yes, ma'am.

The reason that it will be dealt with at the December 1st agenda is because, of course, the Office of Public Counsel and other intervenors have the opportunity to file written responses to Duke's motion for stay, and have indicated that they wish to do so.

The consideration at the December 1st agenda is appropriate because this is a full panel item, and so this type of decision should be made by the full panel.

The resolution of that issue will affect Duke's Issue No. 1A, which was a contested issue included in this docket at the prehearing conference.

COMMISSIONER BROWN: Thank you for specifying the issues.

So then what are the limitations regarding

questioning the witness on Issue 1A today?
     MS. BROWNLESS: At this time, it is our position that the intervenors should be allowed to question Mr. Menendez on Issue 1A, because, obviously, we don't know the outcome of our decision on December 1st.
     CHAIRMAN CLARK: It's still testimony. That doesn't --
     MS. BROWNLESS: It's testimony. Just go ahead and, to the extent that any party wishes to question Mr. Menendez, which my understanding is Public Counsel does, and that would be regarding Issue 1A, is my understanding, then that's appropriate at this time.
     COMMISSIONER BROWN: Thank you for the clarification. And it looks like Mr. Rehwinkel is up.
     CHAIRMAN CLARK: Mr. Rehwinkel, do you have a question?
     MR. REHWINKEL: I just -- if I may, I would like to respond to the Commissioner's question if you deem that appropriate.
     CHAIRMAN CLARK: Sure, Commissioner Brown, yes.
     MR. REHWINKEL: Yes. What Ms. Brownless said

is correct. We have until Monday to respond, and we intend to respond to the motion to stay.

We believe Issue 1A and Issue 11 are impacted by this -- the Bartow order and its treatment in the clause. So we -- you know, our intention to ask questions is not only to 1A, but to 11. And of course, there is a domino effect throughout, which is why Ms. Brownless indicated there are no Type 2 stipulations for Duke, since there is a flow of the impact of these issues throughout the roll-up to the factor. So that's why, and we intend to inquire about that, but we will -- I will address that briefly in my opening.

COMMISSIONER BROWN: Thank you.

Mr. Chairman, if Duke wants to respond as well, I am open to that if you are.

CHAIRMAN CLARK: Certainly.

Duke, would you like to respond, Mr. Bernier?

MR. BERNIER: Thank you, Mr. Chairman. And thank you, Commissioner Brown, for the opportunity to respond.

We do believe that the issues that have been identified by OPC, 1A and 11 and the associated fallout issues, are the issues that are being impacted by our motion for stay.

I would disagree that we need to hear testimony at this point. I believe it's a legal issue that the Commission is going to hear on December 1st. But I understand everybody's position, and the desire to fill out the record, so we won't object to live testimony on the point, but I will cover a little bit of that in my opening as well.

So thank you.

CHAIRMAN CLARK: Thank you, Mr. Bernier.

COMMISSIONER BROWN: Thank you, Mr. Chairman.

CHAIRMAN CLARK: Thank you, Commissioner Brown, for that clarification.

Okay. We are going to move into opening statements. I assume that most of the parties are going to want to make an opening statement. I would like to remind you that you are limited to five minutes per party.

The order that we are going to go in is Duke, then FPL, FIPUG, Gulf, TECO, OPC, FIPUG and then PCS Phosphate.

So we will begin with you, Mr. Bernier.

MS. BROWNLESS: Excuse me, sir.

CHAIRMAN CLARK: I am sorry, Ms. Brownless.

MS. BROWNLESS: It should be, Duke, FPL, FPUC, Gulf, TECO.

CHAIRMAN CLARK: You are correct. FPUC.

All right. Mr. Bernier, you are recognized.

MR. BERNIER: Thank you again, Mr. Chairman. Good morning again, Commissioners.

As we have just kind of discussed, the issues left for DEF is Issue 1A and the associated fallout issues.

Issue 1A asks: What action should be taken in response to the Commission Order No. 2020-0368 regarding the Bartow Unit 4 February 2017 outage?

DEF's position is that no action is appropriate at this time. The referenced order was issued on October 15th, 2020, roughly a month-and-a-half after DEF and the other companies filed their 2021 projection filings along with the proposed 2021 fuel factors. Because DEF had not yet received the order and had an opportunity to review prior to making the 2021 projection filing, the refund was not included therein. For this reason alone, the refund would have been premature.

However, as we have just discussed, yesterday DEF filed a notice of appeal, and along with a motion to day the Bartow order pending a public review in accordance with the Commission's rule

25-22.061. I understand that the motion will be taken up at the December 1st Agenda Conference, but DEF believes the Commission's rule is clear on its face, that in this situation, DEF is entitled to a stay as a matter of right.

If granted, the stay would effectively determine Issue 1A and the associated fallout issues until appeal is decided, but certainly for this year's docket. Mr. Menendez is here to answer questions.

I would just caution everyone, as we know, the Bartow proceeding was sent over to DOAH due to the high amount of confidential information. I understand Public Counsel has indicated the desire to ask questions referencing the order, so I would just bear -- ask the Commission's patience as we go through that question and answer process, and caution Mr. Menendez again to make sure he doesn't state any confidential out loud.

With that, thank you very much.

CHAIRMAN CLARK: Thank you, Mr. Bernier.

Ms. Moncada.

MS. MONCADA: Thank you, Mr. Chairman.

Good afternoon, Mr. Chairman and Commissioners. I appreciate the opportunity to present opening remarks on behalf of FPL.

As Ms. Brownless pointed out, most of FPL's issues have been stipulated. Ms. Brownless and rest of your staff, along with the prehearing officer, Commissioner Fay, have all done an excellent job of getting us all to this point. The only issues that haven't been stipulated are Issues 2F, 2G, and the issues that are impacted by the outcome of those two.

Issue 2F asks: Has FPL made reasonable and prudent adjustments, if any are needed, to account for replacement power costs associated with the April 2019 forced outage at St. Lucie Nuclear Power Plant, Unit No. 1.

And Issue 2G asks the same question with respect to a March 2020 return-to-service delay at St. Lucie Nuclear Power Plant, Unit No. 2.

It is FPL's position that no adjustments are necessary because FPL acted prudently in the circumstances that led to the two events in question.

Here today to testify before you on those two issues is Robert Coffey, a Vice-President in the Nuclear Business Unit with 38 years of experience in the industry. The first 20 of those years being his time with the United States Navy Nuclear Submarine Force.

The April 2019 outage that is the subject of Issue 2F involves a generator ground fault at St. Lucie Unit 1 that was attributed to an insulation fault located in a stator bar.

While FPL's investigation could not definitively confirm the cause, FPL determined that the mechanism that produced the fault was introduced in the stator during a generator rewind performed by Siemens in 2012, and that the condition thereafter degraded in the insulation gradually over the unit's seven years in service.

Our investigation ruled out many potential causes, but three possibilities were neither refuted nor adequately supported.

The first is a ferromagnetic particle introduced during installation. This is also referred to at times as a magnetic turbine.

The second is impact that might have occurred during handling or installation of the stator bar or, finally, a contaminant might have been introduced in the stator bar during manufacture or construction.

The reason the possible causes all point back to the 2012 rewind is the location of the fault, which appeared beneath banding material that was applied in 2012. If the mechanism causing the impact or damage to the bar had occurred after the 2012 rewind, then the banding material would also have been damaged, but here, the banding remained intact.

FPL and Siemens followed established industry standards during the 2012 rewind for insulation testing, for acceptance and quality assurance. And following the 2012 rewind, FPL performed inspections pursuant to standard industry practice and manufacturer recommendations.

After the ground fault occurred and prompted the unit to shut down, FPL determined the proper course of action was to perform a full rewind. This was conducted safely, and the unit was returned to service quickly.

Issue 2G involves a two-day return-to-service delay at St. Lucie Unit 2. This occurred during a scheduled refueling outage where FPL had planned to replace electrical switchgear that was required for plant operations. While implementing that replacement, a configuration conflict was discovered. FPL resolved the conflict, no further corrective actions were required, and FPL's response was appropriate, efficient, and the unit was returned to service safely.

Again, thank you for the opportunity to present this opening statement.

CHAIRMAN CLARK: Thank you, Ms. Moncada.

Ms. Keating, FPUC.

MS. KEATING: Good morning, Mr. Chairman, Commissioners.

As you know, the issues pertaining to FPUC have all been stipulated, so I will happily waive my opportunity to make an opening statement.

CHAIRMAN CLARK: Okay. Thank you very much.

Moving to Gulf.

MS. MONCADA: Gulf waives as well.

Thank you.

CHAIRMAN CLARK: TECO.

MR. MEANS: Good morning, Mr. Chairman. All of the issues for Tampa Electric have been stipulated and all of our witnesses have been excused, so I will just thank staff for their hard work on this docket, and also thank the prehearing officer for bringing these stipulations before you today, and other than that, I will waive my opening statement.

Thank you.
CHAIRMAN CLARK: Thank you very much.
OPC. Mr. Rehwinkel, are you waiving?
MR. REHWINKEL: No, I have brief remarks to make.
CHAIRMAN CLARK: Go right ahead, sir.
MR. REHWINKEL: Thank you, Mr. Chairman.
The Public Counsel objects to Duke Energy Florida's failure to return the $16.1 million in over-collections related to its imprudent operation of Bartow Unit 4.
Regardless of any appeal taken, the Public Counsel's position is that the accounting true-up process inherent in the ongoing fuel recovery process is not subject to the provisions of rule 25-22.061.
On November 9th, we will address the legal arguments in response to the motion to stay filed yesterday by Duke. This motion depends for its resolution on facts, policy and issues of law that you will hear today.
With respect to FPL, the OPC's position in this portion of the hearing is adequately presented in the prehearing order in our statement on the St. Lucie issue.

This case is all about FPL's burden of proof. They have clearly not met the burden of proof regarding the $18 million in replacement costs, and at least $29 million of repair costs that are not at issue at this hearing but are directly related to the events that you will hear about today.

I look forward to cross-examining Mr. Coffey on this issue, but again, it is not the customers, the Public Counsel's or any intervenors' responsibility or burden to make a case or demonstrate imprudence. It is the company's obligation and duty under the law to demonstrate prudence.

Thank you, Commissioners.

CHAIRMAN CLARK: Thank you, Mr. Rehwinkel.

Ms. Putnal, FIPUG.

MS. PUTNAL: Thank you, Mr. Chairman. FIPUG will waive its opening statement.

CHAIRMAN CLARK: All right. Thank you very much.

Mr. Brew, PCS Phosphate.

MR. BREW: Thank you, Mr. Chairman. Very briefly.

We would agree with what Mr. Rehwinkel simply said, so I won't repeat it. We consider the fuel clause to be a reconciliation mechanism that involves all kinds of adjustments, and based on the October 15th final order, we believe that the -- an adjustment should be made to reflect the purposes of that order, notwithstanding the notice of appeal.

Thank you.

CHAIRMAN CLARK: Thank you, Mr. Brew.

All right. Did I get everyone?

All right. Let's move into the stipulated issues and take those first.

Ms. Brownless.

MS. BROWNLESS: Yes, sir.

The Type 2 stipulations for Florida Power & Light are: 2A 2B, 2C, 2D, 2E, 2H, 6, 7, 11, 16, 17, 19, 21, 24A, 24B and 27 through 36.

The stipulated issues for FPUC are: 3A, 8, 9, 10, 11, 18, 19, 20, 21, 22, 24, 35 and 36.

The stipulated issues for Gulf are: 4A, 6, 7, 8, 9, 10, 11, 16 through 19, 20 through 22, 27 through 33, and 34 through 36.

And finally, the stipulated issues for TECO are: 5A, 6 through 11, 16 through 22, 27 through 33, and 34 through 36.

We would request a bench decision on these issues, and the staff is available to answer questions.

CHAIRMAN CLARK: All right. Commissioners, do you have any questions for the staff on any of the stipulated issues?

Seeing none, I will entertain a motion to approve the stipulated issues.

COMMISSIONER FAY: Mr. Chairman -- go ahead, Commissioner Brown.

COMMISSIONER BROWN: Go ahead.

COMMISSIONER FAY: Mr. Chairman --

CHAIRMAN CLARK: Commissioner Fay.

COMMISSIONER FAY: Yeah, I would -- I would move for approval of all Type 2 stipulations as stated. I don't think I need to repeat each one of those for the record.

COMMISSIONER POLMANN: Oh, go ahead.

COMMISSIONER BROWN: No.

CHAIRMAN CLARK: We've got them. We've got them listed.

All right. Commissioner Fay made a motion. Commissioner Brown seconded the motion.

Is there any questions or discussion?

On the motion, all in favor say aye.

(Chorus of ayes.)

CHAIRMAN CLARK: Opposed?

(No response.)

CHAIRMAN CLARK: The motion carries.

All right. Let's begin with our witnesses now. We will move into this particular part of our hearing today.

I understand that the order of the witnesses testifying today are going to be Mr. Menendez on behalf of Duke Energy, and Mr. Robert Coffey on behalf of FPL, the first two witnesses that we are going to take.

I am going to remind the witnesses that their summaries are going be to limited to three minutes each, and I will swear each witness in prior to them taking the stand, and so we will begin with Mr. -- Mr. Bernier.

MR. BERNIER: Thank you, Mr. Chairman.

Duke Energy calls Chris Menendez to the stand, as it were.

CHAIRMAN CLARK: Mr. Menendez, would you raise your right hand and repeat after me?

Whereupon,

CHRISTOPHER A. MENENDEZ

was called as a witness, having been first duly sworn to speak the truth, the whole truth, and nothing but the truth, was examined and testified as follows:

THE WITNESS: I do, sir.

CHAIRMAN CLARK: All right. Mr. Bernier.

MR. BERNIER: Thank you, Mr. Chairman.

EXAMINATION

BY MR. BERNIER:

Q Good morning. Will you please introduce yourself to the Commission?

A Good morning, Commissioners. My name is Christopher Menendez. My business address is 2991st Avenue North, in St. Petersburg, Florida, 33701.

Q Thank you.

And you agree you have just been sworn in, correct?

A Yes.

Q Thank you.

Who do you work for, and what is your position?

A I am employed by Duke Energy Florida as the Rates and Regulatory Strategy Director.

Q Thank you.

And on March 2nd, 2020, did you file direct testimony and exhibits in this proceeding?

A Yes.

Q And on July 27th, 2020, did you file direct

testimony and exhibits in this proceeding?

A   Yes.

Q   And finally, on September 3rd, 2020, did you file direct testimony and exhibits in this proceeding?

A   Yes.

Q   And do you have those with you today?

A   I do.

Q   Thank you.

And do you have any changes to make to your prefiled testimony?

A   Yes, though these revisions have previously been filed with the Clerk. On May 12th, 2020, I filed a revised Exhibit, CAM-3T, identified as Exhibit No. 4 on staff's comprehensive exhibit list. On September 2nd, 2020, I filed revised 2020 actual estimated testimony along with a revised CAM-2, which is Exhibit No. 6 on staff's comprehensive exhibit list. And on September 30th, 2020, I filed a revised CAM-3, which is Exhibit No. 7 on staff's comprehensive exhibit list.

Q   Okay. Thank you.

And with those revisions, if I was to ask you the same questions that are in your prefiled testimony today, would you give the same answers that are contained therein?

A   Yes.

Q Thank you.

MR. BERNIER: Mr. Chairman, we will waive a witness summary.

I would just once again remind Mr. Menendez to refrain from stating out loud any confidential information. And with that, we would tender Mr. Menendez for cross-examination.

CHAIRMAN CLARK: All right. Thank you, Mr. Bernier.

(Whereupon, prefiled direct testimony of Christopher A. Menendez was inserted.)

DUKE ENERGY FLORIDA, LLC

DOCKET NO. 20200001-EI

Fuel and Capacity Cost Recovery
Actual True-Up for the Period
January 2019 - December 2019

DIRECT TESTIMONY OF
Christopher A. Menendez

March 2, 2020

Q. Please state your name and business address.

A. My name is Christopher A. Menendez. My business address is 299 First Avenue North, St. Petersburg, Florida 33701.

Q. By whom are you employed and in what capacity?

A. I am employed by Duke Energy Florida, LLC ("DEF" or the "Company"), as Rates and Regulatory Strategy Director.

Q. What are your responsibilities in that position?

A. I am responsible for regulatory planning and cost recovery for DEF as well as Open Access Transmission Tariff ("OATT") filings with the Federal Energy Regulatory Commission ("FERC"). These responsibilities include completion of regulatory financial reports and analysis of state, federal and local regulations and their impacts on DEF. In this capacity, I am responsible for DEF's Final True-Up, Actual/Estimated Projection and Projection Filings in the Fuel Adjustment Clause, Capacity Cost Recovery Clause and Environmental Cost Recovery Clause.

Q. Please describe your educational background and professional experience.

A. I joined the Company on April 7, 2008 as a Senior Financial Specialist in the Florida Planning & Strategy group. In that capacity, I supported the development of long-term financial forecasts and the development of current-year monthly earnings and cash flow projections. In 2011, I accepted a position as a Senior Business Financial Analyst in the Power Generation Florida Finance organization. In that capacity, I provided accounting and financial analysis support to various generation facilities in DEF's Fossil fleet. In 2013, I accepted a position as a Senior Regulatory Specialist. In that capacity, I supported the preparation of testimony and exhibits for the Fuel Docket as well as other Commission Dockets. In October 2014, I was promoted to Rates and Regulatory Strategy Manager, and in February 2020, I was promoted to my current position. Prior to working at DEF, I was the Manager of Inventory Accounting and Control for North American Operations at Cott Beverages. In this role, I was responsible for inventory-related accounting and inventory control functions for Cott-owned manufacturing plants in the United States and Canada. I received a Bachelor of Science degree in Accounting from the University of South Florida, and I am a Certified Public Accountant in the State of Florida.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to provide DEF's Fuel Adjustment Clause final true-up amount for the period of January 2019 through December 2019, and DEF's Capacity Cost Recovery Clause final true-up amount for the same period.

Q. Have you prepared exhibits to your testimony?

A. Yes, I have prepared and attached to my true-up testimony as Exhibit No. __(CAM-1T), a Fuel Adjustment Clause true-up calculation and related schedules; Exhibit No. __(CAM-2T), a Capacity Cost Recovery Clause true-up calculation and related schedules; Exhibit No. __(CAM-3T), Schedules A1 through A3, A6, and A12 for December 2019, year-to-date; and Exhibit No. __(CAM-4T), with DEF's capital structure and cost rates. Schedules A1 through A9, and A12 for the year ended December 31, 2019, were filed with the Commission on January 23, 2020.

Q. What is the source of the data that you will present by way of testimony or exhibits in this proceeding?

A. Unless otherwise indicated, the actual data is taken from the books and records of the Company. The books and records are kept in the regular course of business in accordance with generally accepted accounting principles and practices, and provisions of the Uniform System of Accounts as prescribed by this Commission. The Company relies on the information included in this testimony in the conduct of its affairs.

Q. Would you please summarize your testimony?

A. Per Order No. PSC-2019-0484-FOF-EI, the estimated 2019 fuel adjustment true-up amount was an under-recovery of $14.5 million. The actual under-recovery for 2019 was $36.0 million resulting in a final fuel adjustment true-up under-recovery amount of $21.5 million. Exhibit No. __(CAM-1T).

The estimated 2019 capacity cost recovery true-up amount was an over-recovery of $1.9 million. The actual amount for 2019 was an over-recovery of $1.1 million resulting in a final capacity true-up under-recovery amount of $0.8 million. Exhibit No. __(CAM-2T).

FUEL COST RECOVERY

Q. What is DEF's jurisdictional ending balance as of December 31, 2019 for fuel cost recovery?

A. The actual ending balance as of December 31, 2019 for true-up purposes is an under-recovery of $35,997,914.

Q. How does this amount compare to DEF's estimated 2019 ending balance included in the Company's Actual/Estimated Filing?

A. The actual true-up amount attributable to the January 2019 - December 2019 period is an under-recovery of $35,997,914 which is $21,535,230 higher than the re-projected year end under-recovery balance of $14,462,684.

Q. How was the final true-up ending balance determined?

A. The amount was determined in the manner set forth on Schedule A2 of the Commission's standard forms previously submitted by the Company on a monthly basis.

Q. What factors contributed to the period-ending jurisdictional net under-recovery of $21,535,230 shown on your Exhibit No. __(CAM-1T)?

A. The $21.5 million is driven primarily by approximately $16.8 million higher fuel and purchased power costs due to approximately $9.1 million of increased purchased power costs, approximately $3.9 million of coal inventory adjustments from semi-annual aerial surveys, and approximately $1.9 million to adjust coal inventory for the retirement of Crystal River Units 1&2.

Q. Please explain the components shown on Exhibit No. __(CAM-1T), sheet 6 of 6, which helps to explain the $11.2 million unfavorable system variance from the projected cost of fuel and net purchased power transactions.

A. Exhibit No. __(CAM-1T), sheet 6 of 6 is an analysis of the system dollar variance for each energy source in terms of three interrelated components; (1) changes in the amount (mWh's) of energy required; (2) changes in the heat rate of generated energy (BTU's per kWh); and (3) changes in the unit price of either fuel consumed for generation ($ per million BTU) or energy purchases and sales (cents per kWh). The $11.2 million unfavorable system variance is mainly attributable to increased firm purchases, partially offset by lower Qualifying Facilities (cogeneration) costs.

Q. Does this period ending true-up balance include any noteworthy adjustments to fuel expense?

A. Yes. Noteworthy adjustments are shown on Exhibit No. __(CAM-3T) in the footnote to line 6b on page 1 of 2, Schedule A2.

Consistent with Order No. PSC-2018-0240-PAA-EQ dated June 8, 2018, DEF included an adjustment of approximately $14.1 million (grossed up to approximately $14.2 million from retail to system) for amortization of the Florida Power Development, LLC ("FPD") qualifying facility regulatory asset. This adjustment is shown on Exhibit No. ___(CAM-3T), in the footnotes to Line 6b on page 1 of 2, Schedule A2, and on line 3, page 1 of 2, Schedule A1. An estimated adjustment of approximately $14.2 million (grossed up to approximately $14.3 million from retail to system) for FPD regulatory asset amortization was included on Schedule E1-B (sheet 2), line A5, columns Jan

Actual through Dec Estimated in the 2019 Actual/Estimated Filing on July 26, 2019.

The ending true-up balance also includes an approximate $1.9 million coal inventory adjustment for the retirement of Crystal River Units 1&2.

Q. Did DEF make an adjustment for changes in coal inventory based on an Aerial Survey?

A. Yes. DEF included an adjustment of approximately $3.9 million to coal inventory attributable to the semi-annual aerial surveys conducted on May 15, 2019 and October 14, 2019 in accordance with Docket No. 19970001-EI, Order No. PSC-1997-0359-FOF-EI. This adjustment represents 2.42% of the total coal consumed at the Crystal River facility in 2019.

Q. Did DEF exceed the economy sales threshold in 2019?

A. Yes. DEF did exceed the gain on economy sales threshold of $1.3 million in 2019. As reported on Schedule A1-2, Line 11a, the gain for the year-to-date period through December 2019 was approximately $1.7 million. Consistent with Order No. PSC-01-2371-FOF-EI, shareholders retain 20% of the gain in excess of the three-year rolling average. For 2019, that amount is approximately $0.06 million.

Q. Has the three-year rolling average gain on economy sales included in the Company's filing for the November 2019 hearings been updated to incorporate actual data for all of year 2019?

A. Yes. DEF has calculated its three-year rolling average gain on economy sales, based entirely on actual data for calendar years 2017 through 2019, as follows:

Year	Actual Gain
2016	$ 887,370
2017	$ 2,269,916
2018	$ 1,649,135
Three-Year Average	$1,602,140

CAPACITY COST RECOVERY

Q. What is the Company's jurisdictional ending balance as of December 31, 2019 for capacity cost recovery?

A. The actual ending balance as of December 31, 2019 for true-up purposes is an over-recovery of $1,050,730.

Q. How does this amount compare to the estimated 2019 ending balance included in the Company's Actual/Estimated Filing?

A. When the estimated 2019 over-recovery of $1,848,509 is compared to the $1,050,730 actual over-recovery, the final capacity true-up for the twelve-month period ended December 2019 is an under-recovery of $797,779.

Q. Is this true-up calculation consistent with the true-up methodology used for the other cost recovery clauses?

A. Yes. The calculation of the final net true-up amount follows the procedures established by the Commission in Order No. PSC-1996-1172-FOF-EI. The true-up amount was determined in the manner set forth on the Commission's standard forms previously submitted by the Company on a monthly basis.

Q. What factors contributed to the actual period-end capacity under-recovery of $0.8 million?

A. Exhibit No. __ (CAM-2T, sheet 1 of 3) compares actual results to the original projection for the period. The $0.8 million under-recovery is primarily due to slightly lower mWh sales.

Q. Does this conclude your direct true-up testimony?

A. Yes.

DUKE ENERGY FLORIDA, LLC

DOCKET NO. 20200001-EI

Fuel and Capacity Cost Recovery
Actual/Estimated True-Up Amounts
January 2020 through December 2020

DIRECT TESTIMONY OF
Christopher A. Menendez

September 2, 2020

REVISED

Q. Please state your name and business address.

A. My name is Christopher A. Menendez. My business address is 299 1st Avenue North, St. Petersburg, Florida 33701.

Q. Have you previously filed testimony before this Commission in Docket No. 20200001-EI?

A. Yes. I provided direct testimony on March 2, 2020.

Q: Has your job description, education, background and professional experience changed since that time?

A. No.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present for Commission approval the actual/estimated fuel and capacity cost recovery true-up amounts of Duke

Energy Florida, LLC ("DEF" or the "Company") for the period of January through December 2020.

Q. Do you have an exhibit to your testimony?

A. Yes. I have prepared Exhibit No.__ (CAM-2), which is attached to my prepared testimony, consisting of two parts. Part 1 consists of Schedules E1-B through E9, which include the calculation of the 2020 actual/estimated fuel and purchased power true-up balance, and a schedule to support the capital structure components and cost rates relied upon to calculate the return requirements on all capital projects recovered through the fuel clause as required per Order No. PSC-2020-0041-PCO-EI. Part 2 consists of Schedules E12-A through E12-C, which include the calculation of the 2020 actual/estimated capacity true-up balance. The calculations in my exhibit are based on actual data from January through June 2020 and estimated data from July through December 2020.

FUEL COST RECOVERY

Q. What is the amount of DEF's 2020 estimated fuel true-up balance and how was it developed?

A. DEF's estimated fuel true-up balance is an over-recovery of $61,083,424. The calculation begins with the actual under-recovered balance of $33,527,567 taken from Schedule A2, page 2 of 2, line 13, for the month of June 2020. This balance plus the estimated July through December

2020 monthly true-up calculations comprise the estimated $61,083,424 over-recovered balance at year-end. The projected December 2020 true-up balance includes interest which is estimated from July through December 2020 based on the average of the beginning and ending commercial paper rate applied in June. That rate is 0.8% per month.

Q. How does the current forecast of fuel costs on Schedule E3 for July through December 2020 compare with the same period forecast used in the Company's Midcourse Correction approved in Order No. PSC-2020-0154-PCO-EI?

A. Light oil and natural gas decreased $10.96/mmbtu (-35%) and $0.36/mmbtu (-10%), respectively. Coal increased $0.13/mmbtu (4%).

Q. Have any adjustments been made to estimated fuel costs for the period January through December 2020?

A. Yes. Consistent with Order No. PSC-2018-0240-PAA-EQ dated June 8, 2018, DEF included an adjustment of approximately $13.5 million (grossed up to approximately $13.6 million from retail to system) for the amortization of Florida Power Development, LLC qualifying facility regulatory asset from January 2020 through December 2020 partially offset by an approximate $13.3 million system ($13.2 million retail) credit related to Citrus. These adjustments are included on Schedule E1-B, line A5, columns Jan Actual through Dec Estimated.

Q. Does DEF expect to exceed the three-year rolling average gain on non-separated power sales in 2020?

A. No. DEF estimates the total gain on non-separated sales during 2020 will be $1,128,563, which does not exceed the three-year rolling average of $1,602,141.

CAPACITY COST RECOVERY

Q. What is DEF's 2020 estimated capacity true-up balance and how was it developed?

A. DEF's estimated capacity true-up balance is an under-recovery of $463,084. The estimated true-up calculation begins with the actual under-recovered balance of $9,343,508 for the month of June 2020. This balance plus the estimated July through December 2020 monthly true-up calculations comprise the estimated $463,084 under-recovered balance at year-end. The projected December 2020 true-up balance includes interest which is estimated from July through December 2020 based on the average of the beginning and ending commercial paper rate applied in June. That rate is 0.8% per month.

Q. What are the primary drivers of the estimated year-end 2020 capacity under-recovery?

A. The $0.5 million under-recovery is primarily attributable to approximately $5.4 million lower revenues offset by approximately $5.6 million related to Florida state income tax change.

Q. Does this conclude your testimony?

A. Yes.

DUKE ENERGY FLORIDA, LLC

DOCKET NO. 20200001-EI

Fuel and Capacity Cost Recovery Factors
January through December 2021

DIRECT TESTIMONY OF
Christopher A. Menendez

September 3, 2020

Q. Please state your name and business address.

A. My name is Christopher A. Menendez. My business address is 299 1st Avenue North, St. Petersburg, Florida 33701.

Q. Have you previously filed testimony before this Commission in Docket No. 20190001-EI?

A. Yes, I provided direct testimony on March 2, 2020 and July 27, 2020.

Q. Have your duties and responsibilities remained the same since your testimony was last filed in this docket?

A. Yes.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present for Commission approval the fuel and capacity cost recovery factors of Duke Energy Florida, LLC ("DEF" or the "Company") for the period of January through December 2021.

Q. Do you have an exhibit to your testimony?

A. Yes. I have prepared Exhibit No.__(CAM-3), consisting of Parts 1, 2 and 3. Part 1 contains DEF's forecast assumptions on fuel costs. Part 2 contains fuel cost recovery ("FCR") schedules E1 through E10, H1 and the calculation of the inverted residential fuel rate. I have also included a schedule to support the capital structure components and cost rates relied upon to calculate the return requirements on all capital projects recovered through the fuel clause as required by Order No. PSC-2020-0165-PAA-EU. Part 3 contains capacity cost recovery ("CCR") schedules.

FUEL COST RECOVERY CLAUSE

Q. Please describe the fuel cost factors calculated by the Company for the projection period.

A. Schedule E1 shows the calculation of the Company's jurisdictional fuel cost factor of 3.090 ¢/kWh. This factor consists of a fuel cost for the projection period of 3.2309 ¢/kWh (adjusted for jurisdictional losses), a GPIF reward of 0.0111

¢/kWh, and an estimated prior period over-recovery true-up of (0.1543) ¢/kWh. Utilizing this factor, Schedule E1-D shows the calculation and supporting data for the Company's levelized fuel cost factors for service taken at secondary, primary and transmission metering voltage levels. To perform this calculation, effective jurisdictional sales at the secondary level are calculated by applying 1% and 2% metering reduction factors to primary and transmission sales, respectively (forecasted at meter level). This is consistent with the methodology used in the development of the CCR factors.

Schedule E1-D, lines 11-12 show the Company's proposed tiered rates of 2.811 ¢/kWh for the first 1,000 kWh and 3.811 ¢/kWh above 1,000 kWh. These rates are developed in the "Calculation of Inverted Residential Fuel Rates" schedule in Part 2 of my exhibit.

Schedule E1-E develops the Time of Use ("TOU") multipliers of 1.251 On-peak and 0.887 Off-peak. The multipliers are then applied to the levelized fuel cost factors for each metering voltage level which results in the final TOU fuel factors to be applied to customer bills during the projection period.

Q. What is the amount of the 2020 net true-up that DEF has included in the fuel cost recovery factor for 2021?

A. DEF has included a projected over-recovery of $61,083,424. This amount includes a projected 2020 actual/estimated over-recovery of $160,850,438 a final 2019 true-up net under-recovery of $21,535,230 as shown in my Direct Testimony filed on March 2, 2020, and the midcourse correction amount of $78,231,785 approved in Order No. PSC-2020-0154-PCS-EI.

Q. What is the change in the levelized residential fuel factor for the projection period from the fuel factor currently in effect?

A. The projected levelized residential fuel factor for 2021 of 3.094 ¢/kWh is a decrease of 0.256 ¢/kWh or 8% from the 2020 levelized residential fuel factor of 3.350 ¢/kWh.

Q. Please explain the decrease in the 2021 fuel factor compared with the 2020 fuel factor.

A. The primary drivers of the decrease in the 2021 fuel factor are a decrease in jurisdictional fuel and purchased power expense of approximately $24 million, decrease in the prior period true-up of approximately $76 million partially offset by an increase in the GPIF amount of approximately $2 million.

Q. Have you made any adjustments to your estimated fuel costs for the period January through December 2021?

A. Yes. Consistent with Order No. PSC-2018-0240-PAA-EQ dated May 8, 2018, DEF included a retail adjustment of approximately $13.25 million (grossed up to approximately $13.26 million from retail to system) for the amortization of Florida Power Development, LLC qualifying facility regulatory asset from January through December 2021.

Q. Is DEF proposing to continue the tiered rate structure for residential customers?

A. Yes. DEF is proposing to continue use of the inverted rate design for residential fuel factors to encourage energy efficiency and conservation. Specifically, the Company proposes to continue a two-tiered fuel charge whereby the charge for a customer's monthly usage in excess of 1,000 kWh (second tier) is priced one cent per kWh higher than the charge for the customer's usage up to 1,000 kWh (first tier). The 1,000 kWh price change breakpoint is reasonable in that approximately 72% of all residential energy is consumed in the first tier and 28% of all energy is consumed in the second tier. The Company believes the one cent higher per unit price, targeted at the second tier of the residential class' energy consumption, will promote energy efficiency and conservation. This inverted rate design was incorporated in the Company’s base rates approved in Order No. PSC-2002-0655-AS-EI.

Q. How was the inverted fuel rate calculated?

A. I have included a page in Part 2 of my exhibit that shows the calculation of the fuel cost factors for the two tiers of the residential rate. The two factors are calculated on a revenue neutral basis so that the Company will recover the same fuel costs as it would under the traditional levelized approach. The two-tiered factors are determined by first calculating the amount of revenues that would be generated by the overall levelized residential factor of 3.094 ¢/kWh shown on Schedule E1-D. The two factors are then calculated by allocating the total revenues to the two tiers for residential customers based on the total annual energy usage for each tier.

Q. How do DEF's projected gains on non-separated wholesale energy sales for 2021 compare to the incentive benchmark?

A. The total gain on non-separated sales for 2021 is estimated to be $1,920,095 which is above the benchmark of $1,682,538. 100% of gains below the benchmark and 80% of gains above the benchmark will be distributed to customers based on the sharing mechanism approved by the Commission in Order No. PSC-2000-1744-PAA-EI. Therefore, since the total gain on non-separated sales is above the benchmark, $47,511 of the gains will be retained for shareholders. The benchmark was calculated based on the average of actual gains for 2018 and 2019 of $2,269,916 and 1,649,136, respectively, and estimated gains for 2020 of $1,128,563 in accordance with Order No. PSC-2000-1744-PAA-EI.

Q. Please explain the entry on Schedule E1, line 11, "Fuel Cost of Stratified Sales."

A. DEF has several wholesale contracts with SECI. One contract provides for the sale of supplemental energy to supply the portion of their load in excess of SECI's own resources. The fuel costs charged to SECI for supplemental sales are calculated on a "stratified" basis in a manner which recovers the higher cost of intermediate/peaking generation used to provide the energy. There are other contracts with SECI and Reedy Creek for fixed amounts of base, intermediate, peaking, solar and plant-specific capacity. DEF is crediting average fuel cost of the appropriate strata in accordance with Order No. PSC-1997-0262-FOF-EI. The fuel costs of wholesale sales are normally included in the total cost of fuel and net power transactions used to calculate the average system cost per kWh for fuel adjustment purposes. However, since the fuel costs of the stratified and plant-specific sales are not recovered on an average system cost basis, an adjustment has been made to remove these costs and related kWh sales from the fuel adjustment calculation in the same manner that interchange sales are removed from the calculation.

Q. Please give a brief overview of the procedure used in developing the projected fuel cost data from which the Company's fuel cost recovery factor was calculated.

A. The process begins with a fuel price forecast and a system sales forecast. These forecasts are input into the Company's production cost simulation model along with purchased power information, generating unit operating characteristics, maintenance schedules, incremental delivered fuel prices and other pertinent data. The model then computes system fuel consumption and fuel and purchased power costs. This information is the basis for the calculation of the Company's fuel cost factors and supporting schedules.

Q. What is the source of the system sales forecast?

A. System sales are forecasted by the DEF Load and Fundamentals Forecasting Department using inputs including a sales-weighted 30-year average of weather conditions at the St. Petersburg, Orlando and Tallahassee weather stations, population projections from the Bureau of Economic and Business Research at the University of Florida, and State of Florida economic assumptions from Moody's Analytics. The Energy Information Agency (EIA) surveys of class energy consumption for the South Atlantic Region are incorporated as well.

Q. What is the source of the Company's fuel price forecast?

A. The fuel price forecasts are based on a combination of third party forecasts and forward contracts currently in place. Additional details and forecast assumptions are provided in Part 1 of my exhibit.

Q. Are current fuel prices the same as those used in the development of the projected fuel factor?

A. No. Fuel prices can change significantly from day to day. Consistent with past practices, DEF will continue to monitor fuel prices and update the projection filing prior to the November hearing if changes in fuel prices warrant such an update.

Q. Is the 2019 GPIF reward discussed in the March 16, 2020 direct testimony of Mary Ingle Lewter included in 2021 rates?

A. Yes. The GPIF reward of $4,407,712 is included on Schedule E1, Line 26 of Exhibit CAM-3, Part 2.

Q. Does DEF's Weighted Average Cost of Capital ("WACC") comply with Order No. PSC-2020-0165-PAA-EU?

A. Yes. The WACC complies with the Amended Unopposed Joint Motion to Modify Order No. PSC-2012-0425-PAA-EU Regarding Weighted Average Cost of

Capital Methodology approved May 20, 2020 in Docket No. 20200118-EU, Order No. PSC-2020-0165-PAA-EU.

CAPACITY COST RECOVERY CLAUSE

Q. Please explain the schedules that are included in Exhibit__(CAM-3) Part 3.

A. The following schedules are included in my exhibit:

<u>Schedule E12-A – Calculation of Projected Capacity Costs – Year 2021</u>

Page 1 of Schedule E12-A includes estimated 2021 calendar year system capacity payments to Qualifying Facilities ("QF") and other power suppliers. The retail portion of the capacity payments is calculated using separation factors consistent with the 2017 Settlement.

The recovery of estimated Dry Casket Storage costs, also referred to as Independent Spent Fuel Storage Installation ("ISFSI") costs, are included on line 40 of Schedule E12-A, page 1. Schedule E12-A, page 2, provides dates and MWs associated with the QF and purchase power contracts.

DEF has shown the 2021 Calculation of Projected Capacity Costs on Schedule E-12A, line 41.

Schedule E12-B – Calculation of Estimated/Actual True-Up - Year 2020

Schedule E12-B, which is also included in Exhibit __(CAM-2) to my direct testimony filed on July 27, 2020, as part of the 2020 actual/estimated true-up filing, calculates the estimated true-up capacity under-recovered balance for calendar year 2020 of $463,084. This balance is carried forward to Schedule E12-A, line 34 to be refunded to customers from January through December 2021.

Schedule E12-D – Calculation of Energy and Demand Percent by Rate Class

Schedule E12-D is the calculation of the 12CP and 1/13 average demand allocators for each rate class. Schedule E12-D also includes the uniform percentage calculation and allocation of the ISFSI revenue requirement to the rate classes.

Schedule E12-E – Calculation of Capacity Cost Recovery Factors by Rate Class

Schedule E12-E, page 1 calculates the CCR factors for capacity costs for each rate class based on the 12CP and 1/13 annual average demand allocators and ISFSI costs from Schedule E12-D. The factors for capacity for the Residential, General Service Non-Demand, General Service (GS-2) and Lighting secondary delivery rate class in cents per kWh are calculated by multiplying total recoverable jurisdictional capacity (including revenue taxes) from Schedule E12-A by the class demand allocation factor, and then dividing by estimated effective sales at the secondary metering level. The factor for ISFSI in cents per kWh is calculated by dividing recoverable costs allocated on Schedule E12-D by estimated effective sales at the secondary metering level. The factors for primary and transmission rate classes reflect the application of metering reduction factors of 1% and 2% from the secondary factor, respectively. The factors allocate capacity costs to rate classes in the same manner in which they would be allocated if they were recovered in base rates. ISFSI costs are allocated to rate classes by applying a uniform percent increase as approved in Order No. PSC-2016-0425-PAA-EI. Pursuant to the 2013 Revised and Restated Stipulation and Settlement Agreement approved in Order No. PSC-13-0598-FOF-EI, DEF has prepared the billing rates for the demand (General Service Demand, Curtailable, and Interruptible) rate classes to be on a kilo-watt (kW) rather than a kilo-watt-hour (kWh) basis. These changes are reflected on Schedule E12-E in columns 11 through 13.

Q. Has DEF used the most recent load research information in the development of its capacity cost allocation factors?

A. Yes. The 12CP load factor relationships from DEF's most recent load research conducted for the period April 2017 through March 2018 are incorporated into the capacity cost allocation factors. This information is included in DEF's Load Research Report filed with the Commission on July 31, 2018.

Q. What is the 2021 projected average retail CCR factor?

A. The 2021 average retail CCR factor is 1.233 ¢/kWh, made up of capacity of 1.216 ¢/kWh and ISFSI costs of 0.017 ¢/kWh.

Q. Please explain the change in the CCR factor for the projection period compared to the CCR factor currently in effect.

A. The total projected average retail CCR rate of 1.233 ¢/kWh is 0.182 ¢/kWh, or 17%, higher than the 2020 factor of 1.051 ¢/kWh. This increase is primarily due to the recovery of the estimated Crystal River South (CRS) net book value existing as of December 31, 2020 and the difference in the in the prior period true-up balance.

Q. Please describe DEF's treatment of the Crystal River South assets.

A. Schedule E12-A, page 1 of 2, line 27, reflects a one-year amortization of the total estimated $80.6M net book value of retired CRS assets as of December 31, 2020. This is consistent with the treatment of the CRS assets in DEF's 2017 Settlement, as approved in Order No. PSC-2017-0451-AS-EU. Per DEF's 2017 Settlement, "…DEF shall be permitted to continue the annual depreciation expense and depreciation rate associated with CRS based on the last Commission-approved depreciation study, which assumed a 2020 CRS retirement date. DEF shall be permitted to recover in 2021, unless a different time for recovery is agreed to by the Original Parties, any remaining CRS net book value existing as of December 31, 2020 through the CCR Clause."

Q. Does this conclude your testimony?

A. Yes

CHAIRMAN CLARK: We will begin cross-examination. The order we are going to go in is OPC, then FIPUG, PCS Phosphate, and then staff.

Mr. Rehwinkel, it's your witness.

MR. REHWINKEL: Thank you, Mr. Chairman and Commissioners.

EXAMINATION

BY MR. REHWINKEL:

Q And hello, Mr. Menendez.

A Good morning, Mr. Rehwinkel.

Q I believe this is my first time cross-examining you. If it isn't, I apologize for forgetting.

A It is the first time, sir.

Q Good. I am glad my memory is working so far.

Tell me again, just in brief terms, what your purpose in this docket is.

A My purpose is to address the DEF's actual fuel and capacity costs true-up amounts for the period January through December 2019, the actual estimated amounts for the period of January to December of 2020, and the projected amounts for the period of January through December '21.

Q So it would be fair to say your testimony supports the costs that would be included in rates that will be set beginning January 1, or thereabouts, in

2021?

A   For fuel and capacity, yes, sir.

Q   Yes, sir, okay.

Are you employed by DEF or by what's known as DEVS, D-E-V-S?

A   DEF, sir.

Q   Okay. Isn't it true that you filed testimony in all three rounds of this docket in this year's hearing cycle?

A   Yes, sir.

Q   And is it also true that your testimony in your -- your September 3rd testimony proposes a reduction in the fuel factor revenue -- that customers will pay beginning in 2021?

A   Yes. The 2021 fuel factor is a reduction as compared to 2020.

Q   Okay. So that would be a reduction from 3.350 cents per kilowatt hour to 3.09 cents per kilowatt hour?

A   Are you looking at -- which factor are you looking at, sir?

Q   For fuel -- just for fuel alone.

A   I see on the exhibit -- or the Schedule E1 of 3.09, yes, is the current one, or the one for 2021.

Q   Okay. And everyone knows we are here today to talk about Bartow. The impact of the Bartow decision

would be reflected in the fuel factor only, not capacity, right?

A Yes, sir.

Q Okay. And isn't it true that you filed testimony in the 2017, 2018 and 2019 fuel hearing cycles?

A Yes, sir.

Q Okay. Isn't it also true that DEF received orders authorizing to you collect all, or 100 percent of the costs that were submitted by you in your testimony and in the petitions related to fuel cost recovery in those years?

A Yes, sir. The amounts that we collected in the fuel rates in those years was approved by the Commission.

Q Okay. And those are the amounts that you requested recovery for, right?

A Yes, sir.

Q Okay. So another way of saying that would be that none of the costs that you sought to recover in '17, '18 and '19 were disallowed by the Commission, correct?

A Correct. No disallowances, sir.

Q Okay. Now, wouldn't you agree with me that in 2017, for an approximately 60-day period between the end

of February and the beginning of May, that DEF experienced an outage at the Bartow unit, specifically Unit 4, the steam generator?

A Can you repeat those dates again, Mr. Rehwinkel?

Q Yes, the end of February to the beginning of May of 2017.

A I don't have the exact date, sir. I do recall it was approximately a two-month period.

Q Okay. And isn't it true that due to the installation of a pressure plate, that for the period of approximately May of 2017 through September 2019, that the Bartow Unit 4 experienced a derating of as much as 40 megawatts of the capacity of that unit on a periodic basis, depending upon whether the capacity was needed in the dispatch of the unit?

A Mr. Rehwinkel, I am not an --

MR. BERNIER: Mr. Chairman -- Mr. Chairman, I apologize, I need to object.

This goes well beyond the scope of any testimony Mr. Menendez has filed in this docket. He is not an operational witness. These are matters that have been -- that have been the subject of litigation and the order that's under appeal. I just don't know where it is that we are going with these, and how it's pertinent to anything at issue.

CHAIRMAN CLARK: So let's stick to the scope of the testimony.

And, Mr. Menendez, is this not -- nowhere -- is this anywhere in your testimony?

MR. REHWINKEL: May I be heard?

CHAIRMAN CLARK: In one second.

THE WITNESS: No, Mr. Chairman.

CHAIRMAN CLARK: Mr. Rehwinkel.

MR. REHWINKEL: Yes, Mr. Chairman. The issue here is not what's in his testimony, it's what's not in his testimony. And I have one exhibit, which is the Bartow order, which is Exhibit 1C, and it is order PSC-2020-0368A-FOF-EI. This order has the facts that DEF did not challenge and are not subject to the appeal to the Supreme Court. And these facts include findings by the DOAH judge that the Commission adopted that said there was a derating that generated $5 million in replacement power costs over a period from May of 2017 through September of 2019 --

MR. BERNIER: Mr. Chairman, we will stipulate that that order speaks for itself. I am just saying that Mr. Menendez is not a witness who has any personal knowledge about these issues. The order is what the order is.

I would take note, we have filed a notice of appeal, but we have not filed a substance of appeal. So I think it's a little presumptuous to say what's going to be under that appeal. We haven't drafted it yet.

But other than, that I am simply -- I am not disputing that the order says what the order says. I am just saying that Mr. Menendez is not a witness here who can -- who can speak to these issues, nor do I know how it would be pertinent.

MR. REHWINKEL: Mr. Chairman, I didn't finish my response to the original objection.

CHAIRMAN CLARK: Okay. Go ahead, Mr. Rehwinkel.

MR. REHWINKEL: The reason we are here today is to identify whether there are costs that should be credited in the fuel clause, and to identify the types of those costs.

I don't really need Mr. Menendez to agree to the facts that Duke stipulated to, or agreed to in the order. And I would agree with Mr. Bernier, that the order speaks for itself. But I do need to ask Mr. Menendez whether he has reflected certain costs in the fuel cost recovery over the period that leads to the amount that the customers are currently paying, and will be paying in 2019.

So my purpose of asking these questions is to establish factual predicate about what costs are in and what costs are not reflected in the fuel factor. And I believe I am entitled to some leeway on that. And if Mr. Bernier's objection is sustained, I will ask the Commission to accept a proffer of the cross-examination so that a proper record can be made for appeal.

CHAIRMAN CLARK: So I am going to give you just a little bit of leeway here, Mr. Rehwinkel. Mr. Menendez, if he doesn't know the answer to the question, he is going to answer no. Let's don't dig. Let's move on from that point.

All right. Proceed.

BY MR. REHWINKEL:

Q So I think the last question to you, Mr. Menendez, and your answer through the Chairman was that you don't know about whether there was a derate as much as 40 megawatts depending on a dispatch of the unit over the period of May of '17 through September of 2019; is that right?

A That is not my knowledge, sir.

Q Okay. Wouldn't you agree that your testimony reflects a replacement power cost if there is an outage -- strike that, and let me ask it this way: Wouldn't you agree that your -- the cost that you present in your true-up, your AE, or actual estimated, and your projected filings includes as a component request for cost recovery for replacement power costs that are required because of an outage of a unit that is otherwise planned to operate?

A Are you addressing a specific outage, Mr. Rehwinkel?

Q No. I am asking you a question as to the nature of the testimony that you present year in and year out on behalf of the company?

A I can't speak to hypothetical outages that may or may not occur.

Q Well, in the 2017 outage -- we can argue about this all day long if you would like, but the 2017 outage had replacement power costs, and you submitted cost recovery for those replacement -- for those replacement power costs, did you not?

A Those costs have been recovered.

Q My question was did you present cost recovery for those costs -- cost recovery testimony for those costs?

A I would have to go back and check prior year filings. I -- I do not believe it is in my current testimony.
Q Okay. Well, let's look at it this way: You would agree that outage and derating circumstances caused Duke to incur replacement power costs in the years 2018 and 2019, would you not?
A It is not my area of knowledge, sir.
Q You don't know whether you have ever presented testimony seeking replacement power costs?
A Testimony has been presented in prior years. Sir, you seem to be asking a specific question about an operational issue.
Q I am asking if you have presented testimony seeking cost recovery for outage costs in prior years?
A In prior years, we -- I have -- we have included cost recovery related to outage costs.
Q And one of those outages was the 2017 Unit 4 outage in Bartow, correct?
A The costs associated with those outages have been recovered, yes.
Q But you presented testimony specifically seeking recovery of those costs, right?
A Again, as I said, I would have to go back and take a look at the prior testimony that I specifically

filed. I -- to my knowledge, I do not have anything in my current testimony related to that.

Q You can't answer my question about whether you sought -- well, let me ask it this way: Isn't it true that in 2017 you filed testimony that included a stipulation with the Public Counsel that -- and the FIPUG and White Springs -- that you would not recover in 2018 fuel factor the costs of the Bartow outage?

A Is there a document you can point me to, Mr. Rehwinkel?

Q Well, do you have a copy of the 2017 prehearing order?

MR. BERNIER: Mr. Rehwinkel, that's the 2017 prehearing order?

MR. REHWINKEL: Yes, order 2017-0399.

MR. BERNIER: Okay, I have got it.

THE WITNESS: I have that, Mr. Rehwinkel.

BY MR. REHWINKEL:

Q Can you turn to page 31?

A Yes, sir, I am there.

Q Do you see a stipulation there under Issue 1B that reads: Duke Energy Florida and the parties stipulate that Duke has not included the approximately $10,973,639 in retail replacement power associated with the unplanned Bartow outage in developing rates for

2018. These costs will remain in the over/under account to be considered in Docket 20180001-EI for recovery in 2019 rates, subject to normal intervenor challenge and Commission reasonableness and prudence review and approval?

A Yes, sir, I do.

Q Okay. Does that refresh your recollection that you did not include the Bartow outage costs in 2018 for recovery in the 2018 fuel factor?

A Yes, sir. It's just a matter of understanding the sequencing of years, sir.

Q Okay. So would it also be true that you sought recovery for that approximately $11 million related to the Bartow outage in 2019's fuel factor?

A Do we have another document would can go to, Mr. Rehwinkel --

Q Well --

A -- to refresh my memory?

Q You don't know?

A It has -- Mr. Rehwinkel, it has been recovered. The specific year, I don't have that document in front of me.

Q So you are the witness for the company seeking cost recovery and you don't know when those costs were recovered?

A Mr. Rehwinkel, I know it was recovered in a prior year, which -- the specific year, if you could point me to a document, I would be happy to review that.

Q Well, it's not in this year's, is it?

A No, sir.

Q Is it in -- was it in -- so it wasn't in '18, so it had to be in 2019, right?

A Yeah, if it was not in 2018, then it was in 2019.

Q Okay. So if it was in 2019, you filed testimony in March of 2020 seeking to true-up the 2019 factor, right?

A Yes. 2020 -- the current docket includes the 2020 final true-up.

Q Okay. So to the extent all of that dollar figure I read there wasn't recovered in 2019, true-up recovery would occur in 2020?

A That is the way in which the true-up works, sir, yes, sir.

Q Okay. So you can't really say whether it's all been recovered. The recovery process is ongoing, right?

A If it was in the 2019 fuel factors, we would have collected those revenues in 2019. If there was a residual difference in any fuel recovery amount, it does carry over to the true-up in the next proceeding.

Q Okay. So -- yeah, and that's all I wanted to ask you about that.

With respect to that stipulation that we looked at in the -- in that order 2017-0399 on page 31, tell me what the over/under account is there.

A Just a moment, sir.

The over/under account that is being referred to is otherwise known as the true-up balance, or the true-up variance.

Q Okay. How does that operate?

A It is a variance between the revenues collected an the expenses occurred in the clause account.

Q Okay. So when the stipulation refers to remain in the over/under account, that means that those -- that $11 million was not submitted for cost recovery from customers, but it doesn't mean that Duke wasn't able to recover those costs, because you accounted for them in that account and then you submitted them for recovery in the next year, right?

A Yes, if they were included in 2019, they would have been included in the 2019 projection file.

Q Okay. So Duke never lost the opportunity to have the Commission consider those cost recovery just by

holding them in that over/under account, right?

A That's a legal question for the -- as to the Commission, Mr. Rehwinkel. That's not my area.

Q Well -- okay, let's ask you a factual question. You didn't recover them, submit them for recovery in 20 -- well, Bartow outage, you have agreed, occurred in May -- in early 2017, right?

A Early 2017, yes.

Q And you also would agree with me that there were replacement power costs incurred because of that, because that's what the stipulation says, right?

A Yes.

Q Okay. And you would agree with me that you didn't submit them for recovery in 2018, but you did in 2019, right?

A Subject to check, I will.

Q Okay. So my question to you is you incurred them in '17, you forwent the opportunity to recover them in 2018, but you recovered them in 2019; as a matter of fact, did you not lose the opportunity to recover fuel replacement costs that you incurred in 2017 in a subsequent year, right?

A They were recovered in a subsequent year.

Q Okay. So your opportunity was preserved to recover those costs in the fuel clause, right?

A We recovered them in a future year, Mr. Rehwinkel. If it's a legal clarification on the preservation, it's not my area.

Q Okay. I understand that.

So do you have Exhibit 1C with you?

A Yes, sir, I do.

Q I would like you to turn to --

MR. REHWINKEL: Excuse me, Mr. Chairman. In light of some of the objections, I am trying to cut out some of the questions and shortcut this.

CHAIRMAN CLARK: No problem.

BY MR. REHWINKEL:

Q I would like you to return -- to turn to what is revised OPC Exhibit 1C, Bates number 57, which is page 56 of the order, and it's in Attachment A, and specifically to paragraph 124; and if you could tell me when you get there.

A I apologize. My mic muted. I am there.

Q Okay. Now, do you see -- and this is -- I don't think anything on this page that's not redacted is confidential, would you agree with that? Or maybe your counsel needs to agree with that.

MR. BERNIER: I will agree with that. Yes.

MR. REHWINKEL: Okay.

BY MR. REHWINKEL:

Q So it's possible that -- well, let me strike that question and ask you to move back to page 47. These are the findings of fact. So we can stay away from the conclusions of law.

A To make sure I am there, Mr. Rehwinkel, it has OPC Exhibit 1C, this is 048 in the top -- (inaudible) -- hand corner.

Q Actually it will be 047. It's page 46 of the order and 047 of our exhibit.

A I see. I am there.

Q Okay. Do you see that in paragraph 80 there, under replacement power and derating costs, that it says: Further, the record evidence established that DEF incurred replacement power costs from May 2017 through September 2019, the period of the, quote, derating, close quote, of the steam turbine, i.e., the reduction in output from 420 megawatts to 380 megawatts while it operated with the pressure plate. These costs calculated by year are 1,675,561 2017, 2,215,648 2018 and 1,125,573 2019, for a total of $5,016,782; do you see that?

A I see it is written there, yes, sir.

Q Okay. Now, as the witness seeking cost recovery in the fuel factor, would you agree that DEF recovered costs for derating, or maybe still is

recovering costs for the derating as identified in this paragraph 80 in the fuel factor for the years '17, '18 and '19?

A Mr. Rehwinkel, I am not familiar with these figures. I see that they are on the page, and they are as you described them. However, I have no detailed information on these figures.

Q Okay. That's fair enough.

Let me ask you this: Regardless of whether those numbers specifically apply in those amounts for those years, would you agree that in some dollar amount, DEF has recovered, or is still recovering, costs associated with replacement power associated with the derating that the judge found in this findings of fact?

A Mr. Rehwinkel, I am not familiar -- any derating is not my area of knowledge.

Q Replacement power, though, is something that you account for, right?

A Yes.

Q Okay. Would you agree that there are replacement power costs that are being recovered, or have been recovered through the fuel factor by DEF in the period 2017 through 2020? We are in 2020 right now.

A The replacement power costs that we discussed previously in the 2017 prehearing documents, I am familiar with those. And as I said previously, those amounts have been recovered.

Q Those amounts were just for the two months, or 60-day period while the unit was down in its entirety, right?

A Yes, sir. That is my understanding. Yes.

Q And to the extent there were replacement power costs incurred because of the pressure plate and the derating that the judge found, your -- those costs would have been submitted by you in your accounting for all of Duke's -- Duke Florida's fuel cost, correct?

A And I am saying, Mr. Rehwinkel, that I am not an operations person on the derating of the unit and impacts from the derating of the unit, I don't have knowledge on the impacts of derating a unit.

Q If there were derating costs -- well, if there were replacement power costs associated with derating, Duke would have sought recovery for those costs in a period which -- after they were -- they were incurred, correct?

A In a hypothetical derating scenario, Mr. Rehwinkel?

Q Yes, a hypothetical derating scenario?

A I can't answer the hypothetical without understanding the -- what the specifics might have been of that, I -- I can't answer a hypothetical, sir.

Q All right. Are you familiar with the over/under account, is that within the purview of your testimony?

A Yes, sir.

MR. BERNIER: Mr. Chairman, if I may. I think we are at kind of at an impasse where Mr. Menendez is saying almost the same thing, that he is not familiar with some of these amounts.

If it helps, again, I am willing to stipulate that the figure that is shown in paragraph 81 is the amount that the ALJ found should be refunded, and that the Commission has ordered a refund that we have now subsequently appealed, and I think we would stipulate that that is not incorporated into the 2021 projection filing, if that will get us where we need to go.

CHAIRMAN CLARK: Thank you.

MR. REHWINKEL: If I could just get -- I want to ask this question about the over/under.

CHAIRMAN CLARK: All right. So let -- let me address one issue, and I think Mr. Menendez is separating replacement power from the downrating, and so if we can leave those two issues separate, Mr. Rehwinkel, I think we can move along with the witness.

BY MR. REHWINKEL:

Q My question to you, Mr. Menendez, is: Are there any amounts in the over/under account that are being withheld related to a derating cost replacement power cost, withheld from cost recovery?

A I am not aware of any true-up or over/under amounts being withheld at all.

Q And would you be if there were?

A Would I be aware?

Q Yes.

A Yes.

Q Okay. All right. I think that -- that gets me where I need to be there.

So is it fair to say, based on, I think the sum of the testimony that we've gotten through thus far, that you did not submit any testimony in 2017, 2018 or 2019 or 2020 seeking affirmative cost recovery for replacement power costs associated with derating?

A Again, Mr. Rehwinkel, I -- I -- I would want to go back and double check the testimonies from those prior years to make sure that I don't misstate something as I sit here now. I have not stated that in my 2020 testimony, or in the testimony in the current docket.

Q Okay. And, I mean, we can go through the

2017, 2018 and 2019 prehearing orders --

A Mr. Rehwinkel, I just don't want to misremember something --

Q Sure.

A -- and misstate something.

Q Okay. But subject to check, you will agree with me, there is nothing in your 12 sets of testimony since 2017 where you affirmatively request recovery for deratement -- derated replacement power costs, would you agree with what?

A Subject to check, I do not recall an aspect of that in my testimony.

MR. REHWINKEL: Okay. If you would just give me a second, Mr. Chairman, I am cutting out a lot of questions based on where we've gotten so far.

BY MR. REHWINKEL:

Q All right. So if you go to Exhibit 1C, and turn to Bates stamp page number four.

A It would be order of page number three, Mr. Rehwinkel?

Q Yes, sir.

A I am there.

Q Okay. In the first full paragraph there, you would agree that this order recounts that the ALJ issued his recommended order on April 27th, 2020?

A I see where it says the ALJ issued his recommended order on April 27th, 2020.

Q Okay. You have no reason to disagree with that, right?

A No.

Q Okay. Now, you filed testimony this year on March 3rd of 2020, true-up testimony, correct?

A For 2019, yes, sir.

Q Yes, okay. So you would not have considered in that testimony an order of the judge that came out on April 27th in any way, is that right, since those true-up for 2019?

A No, sir. It came after the filing had already been made.

Q Okay. Now, you didn't file a midcourse correction testimony to account for the judge's order when it came out, did you?

A No, sir.

MR. BERNIER: I am going to object again, Mr. Chairman. That was a recommended order from an ALJ. There was still a lot of process left. I don't know why anybody would have filed anything at that point, but we will stipulate we didn't.

MR. REHWINKEL: Well, he already said that he didn't. I think that's fine.

BY MR. REHWINKEL:

Q Did you -- did you place the 16 million -- $16.1 million that the judge ordered to be returned to customers in an over/under account?

A No, Mr. Rehwinkel, place it in an over/under account?

Q Yes.

A It was -- it was -- I think, as we agreed, it had already been recovered in a prior year.

Q Well, that was a debit that you recovered in a prior year, correct?

A No, the revenues were collected.

Q It's a cost that the customers pay. It's submitted as a debit, and then when it's collected, it's a credit, right, it's a credit to the company's revenues, right?

A The revenues offset the expenses.

Q Right, which is a debit?

A The -- yes, the expense would be a debit, the credit -- the revenue would be a credit.

Q Okay. So when you -- in 2017, when you put the $11 million in the over/under account, you put it in there as a debit, right?

A Not to get -- not to get too caught up on the dealt and credits and the flow in between the different accounts, but it would have been in -- in 2017 costs -- as we said in the prehearing statement, it remained in the true-up balance.

Q But as a debit that needed to be recovered in a future period, right?

A If we needed -- yes, it was being held as the stipulation, as said, for the next year's docket.

Q Okay. Now, when the judge issued his order, you could have reflected a $16 million credit in the over/under account, right?

A Mr. Rehwinkel, I think as Mr. Bernier said, the process -- we had not received anything from the Commission at that time.

Q So you would agree with me that after the judge filed his recommended order, the parties filed responses to that, and then on July 27th, you filed your AE testimony, your actual estimated testimony, right?

A Yes, I believe it was filed on the 27th.

Q And at that point, you didn't make any adjustment to remove the $16 million for cost recovery for 2021, is that right?

A There was no adjustment in my actual estimated.

Q Okay. And just for the record, why would you not have made an adjustment in your AE testimony?

A We -- the process was still under way, Mr. Rehwinkel.

Q Okay. Now, on August 14th of 2020, the staff filed its recommendation that the Commission adopt the recommended order of the -- of the ALJ, would you accept that subject to check?

A Subject to check, I will accept the date, Mr. Rehwinkel.

Q Okay. And I think you would agree that on September 1 of 2020, the Commission voted to adopt staff's recommendation?

A Subject to check, I will accept the date, Mr. Rehwinkel.

Q Okay. And two days later, you filed projections for fuel costs in 2021, right?

A On September 3rd, we filed the projection for '21, yes, sir.

Q In that testimony, you didn't make any adjustments to implement the Commission's vote, or put the $16.1 million as a credit in the over/under account, did you?

A There was no $16 million credit.

Q And your testimony didn't reflect that as well, right?

A No, it is not in my testimony.

Q Can you tell me why you didn't at that point?

A Mr. Rehwinkel, if it's getting to a legal question between a Commission vote and a Commission final order, I am not an attorney, and that is not my area of knowledge.

Q Okay. Was there any reason that you thought that the Commission's order reducing the Commission vote to writing would be changed so that the number would change, that there wouldn't be a $16 million credit required?

MR. BERNIER: Mr. Chair, to the extent that he is getting into what could be a privileged conversation, I am going to object to this line of questioning. I think he has already answered.

CHAIRMAN CLARK: Yeah, I will sustain the objection.

BY MR. REHWINKEL:

Q We are -- today is September 3rd -- or November 3rd, and the Commission voted on September 1st. Was 60 days an inadequate period of time for you to make an adjustment -- a one-time adjustment to credit the $16 million to the fuel cost recovery?

A Mr. Rehwinkel, the final order wasn't issued until October 15th, and it wasn't received until October 16th.

Q Okay. How many days do you generally need to make an adjustment to a fuel filing to incorporate a one-time credit?

A It depends on the adjustment, Mr. Rehwinkel.

Q I mean, is a -- is there a difference between a $16 million adjustment and a $32 million adjustment in terms of the time it takes to put it into the system and develop the factors?

A Depending on the nature of the adjustment, the dollar amount itself doesn't have an impact. It's more the nature of the adjustment.

Q So you would agree that the $16.1 million is a one-time credit to the extent that order is sustained and up held, is that right?

A If the order stands up, but, Mr. Rehwinkel, the -- as I said, the projection filing was made on September 3rd. We did not have a Bartow order until the 15th or 16th of October.

Q Well, I guess my original question to you was how long does it take to reflect the impact of a $16.1 million one-time credit?

A To my knowledge, Mr. Rehwinkel, we have not received that request.

Q What do you mean you haven't received it? You mean in the form of a final final final order?

A No, sir. Not in the form of a final final final order.

Q Well, how would you need to receive that request to reflect it? I guess that's what I am confused about.

A We did not receive --

MR. BERNIER: I am sorry, Mr. Rehwinkel, I didn't -- I apologize. I wasn't trying to interrupt. I just didn't hear your question. I apologize.

MR. REHWINKEL: That's okay. He said he had not received a request to make a one-time credit. I think that's generally what he said.

BY MR. REHWINKEL:

Q And I am asking what form would you have needed to have received the request in order to effectuate it?

A The, I believe, discovery request, Mr. Rehwinkel.

Q From whom?

A Whoever was interested in the information.

Q Okay. So you don't see it as your obligation to make adjustments to the fuel factor unless somebody asks you to?

A Mr. Rehwinkel, the --

MR. REHWINKEL: Was there an objection?

MR. BERNIER: Yes. I apologize.

You are asking him a legal conclusion of when he needed to make this adjustment. That's the way I am understanding the question. I think he's answered that question.

CHAIRMAN CLARK: Mr. Bernier, I can't --

MR. BERNIER: I object to the extent you are asking for a legal conclusion.

CHAIRMAN CLARK: I am having a difficult time understanding you, Mr. Bernier.

MR. BERNIER: I certainly apologize.

My objection was that the extent he is asking for a legal conclusion of when he -- Mr. Menendez needed to effectuate the schedules, I am objecting to him asking him for a legal conclusion. I think he has asked and answered the question about when he received the final order, and Mr. Menendez is saying he has not received any discovery requests to put this together. There is a order that came out that is now subject to appeal. I think that the question he is asking him is did you have an obligation to update his schedules, and I am objecting that that is a legal conclusion.

CHAIRMAN CLARK: I tend to agree.

MR. REHWINKEL: Mr. Chairman, I -- that's not the question I asked. We can ask the court reporter to read it.

CHAIRMAN CLARK: Mr. Rehwinkel, you can ask the question that you asked earlier again and I will instruct the witness to answer it. I -- you are correct, that is the no the question. You asked how long it would take to implement a change if he was given one. If the witness knows the answer to that, he can certainly answer it.

MR. REHWINKEL: Well, the question I want to ask him is -- he said I hadn't received a discovery request, and I asked -- well, I was trying to understand what it takes for him to make a credit to the fuel clause, and I think he said a discovery request. And I wanted to understand the basis for that, is that -- is that some -- where did that come from?

CHAIRMAN CLARK: Mr. Menendez, you can answer the question to the extent that you know the answer.

THE WITNESS: Thank you, Mr. Chairman.

Mr. Rehwinkel, I was not indicating that a discovery request is what prompts an adjustment to the fuel clause. That if -- that is not -- that is not my response.

BY MR. REHWINKEL:

Q Okay. So I think we've established that the -- except maybe for some minor true-ups, that you recovered the $11 million for the 2017 event, is that -- can we agree on that?

A The amount from the 2017 prehearing order, yes, sir.

Q Yes. Now, if an appeal -- well, an appeal was taken yesterday, and I don't want you to -- I am not asking your opinion about how long it takes for an appeal to go, but I want to ask you a question that is hypothetical, and I want to get your response to how the mechanics of the fuel process would work.

Appeal was taken yesterday, and if it takes, assume for the sake of my question, six months for briefing to occur, and maybe more based on extensions that are routinely asked for and granted by the Court -- are you following me so far?

A I am trying, Mr. Rehwinkel, but I am not -- I am not an attorney, and I am not familiar with the operations of the -- of the Florida Supreme Court.

Q I am just asking you some questions based on your knowledge of the calendar, okay, the 12-month calendar, okay?

A Okay.

Q So if briefing occurs and is concluded in, say, May of 2021, which is the next year, and oral argument occurs in the late summer or early fall of 2021, and a written decision comes out from the Court denying the appeal, and -- on December 15th of 2021, and the order is final, and it's ordered that you refund $16 million to the customers through the true-up process in the clause, when would that $16 million be reflected on customer bills?

A Again, Mr. Rehwinkel, there is a lot of questions going around about the timing of the Florida Supreme Court, and how things are going to be handled. I don't -- I am not an attorney. I don't know all the legal ramifications and the timing of when things come down.

Q All right. So let me ask it -- let me -- let me ask it this way: If you get a final order from the Florida Supreme Court on December 15th of 2021, when would those -- that $16 million, plus interest, be refunded or credited to the bills of customers?

A Again, Mr. Rehwinkel, the -- the legal ramifications of when things are coming down from the Florida Supreme Court, I would need to --

Q You don't have to apply the Florida Supreme

Court. I am just asking a final order.

A Yes, sir, and I am saying, as far as legal conclusions about when things ultimately finish, I would want to just make sure that I am -- I understand from legal counsel what the various different things mean from the Florida Supreme Court.

MR. BERNIER: Mr. Rehwinkel, I will help you real quick.

So, Chris, if that happens on December 15th, 2021, that's the end of the road, short of, well, I guess, motions for reconsiderations, but let's just pretend that's the end of the road and there is nothing else that can happen.

Will that help the hypothetical, Mr. Rehwinkel, but let's say that that's it, are we right?

MR. REHWINKEL: That's what I am asking.

MR. BERNIER: Thank you.

THE WITNESS: The -- in that event, the amount would be recorded in December, it would be incorporated in the true-up balance, and it would be reflected in customer rates the next time the rates were set for fuel.

BY MR. REHWINKEL:

Q Okay. So just what I am trying to get at is

you would reflect it in the true-up balance, that would show up in your March 2022 testimony, right --

A   Yes.

Q   -- assuming you are the one filing the testimony for that cycle, right?

A   Right, and assuming it's in March, yes.

Q   Right.

A   Traditionally is.

Q   And then that $16 million adjustment would show up on customer bills on 1/1/2023, correct? Assuming being when your billing cycle starts for the first cycle.

A   It would be -- I -- the process -- that would be the next projection process, would be the projection filing that year for the following year, yes.

Q   Okay. So -- and then that $16 million would be flowed through the customers -- to the customers through the factor over the next 12 months, right?

A   Yes.

Q   All right. So customers would receive, under the hypothetical, their money back at the end of December 2023, subject to any sales related true-ups in 2024; is that right?

A   It would be over the course of 2023, not at the end of 2023, Mr. Rehwinkel.

Q So it would be completed at the end of 2023, subject to any sales related true-ups in 2024, right?

A Ignoring those, yes.

Q Okay. All right. Mr. Menendez, those are I will the questions I have for you. Thank you for your patience and working through this.

A Thank you, Mr. Rehwinkel.

Q Thank you.

CHAIRMAN CLARK: Thank you, Mr. Rehwinkel.

Okay. We are going to take our break right there. When we come back, we are going to pick up with FIPUG. It is 10 after 12:00, so we will return at exactly one o'clock eastern time. One o'clock eastern time we will resume.

Any questions or comments? Commissioners, everybody good?

All right. We stand in recess until 1:00.

(Lunch recess.)

CHAIRMAN CLARK: We are going to go ahead and get started back. I believe we left off, OPC had finished their cross-examination and, I believe that brings us to FIPUG.

Ms. Putnal, are you available?

MS. PUTNAL: Thank you, Mr. Chairman. FIPUG has no questions.

CHAIRMAN CLARK: All right. Thank you.

Mr. Brew, your witness.

MR. BREW: Thank you, Mr. Chairman. Can you hear me?

CHAIRMAN CLARK: Yes, sir. We can hear you great.

MR. BREW: Great. Thank you.

EXAMINATION

BY MR. BREW:

Q Good afternoon, Mr. Menendez.

A Good afternoon, Mr. Brew.

Q This shouldn't take more than a couple of hours, we will be fine.

Quickly, your job in this docket is to present accurate, reasonable and prudent fuel costs that reconcile actual and estimates to develop fuel factors for next year?

A Yes, sir, for the 2019 final true-up to 2020 actual estimated going into the '21 -- 2021 projections fuel factors.

Q Okay. And you -- at the beginning of your testimony, you mentioned that you had provided revised exhibits that are numbered 4, 6 and 7, is that right?

A Staff 4, 6 and 7, yes, sir.

Q Okay. And those involve revisions to your

previously filed actual and estimated calculations, right?

A I believe one was to the final true-up, one was to the actual estimated, and I believe the third may have been to the projection filing.

Q Okay. And those updates, both up and down, would be a normal part of the process in this clause docket, right?

A Yes, sir, the correcting of an error in a previously filed document, yes.

Q Okay. And am I also correct that your responsibilities, as we've discussed with respect to the Bartow unit outage, are -- involve basically the accounting and tabulation of the costs, not necessarily what's going on operationally, right?

A Accounting for the actual fuel costs, yes, sir.

Q Okay. And you discussed earlier with Mr. Rehwinkel that in the 2017 prehearing order in the fuel docket, there was a stipulation that covered what were then calculated replacement fuel costs associated with the Bartow unit outage that began in February, right?

A That is correct.

Q And that calculation of $10.9 million, the retail replacement power costs, that would have come

from you or your office?

A It would have -- we have a department would have calculated the -- the -- the actual fuel costs are the costs, and then a separate calculation is run as if the outage had not occurred, and then the difference between those two becomes what would be called the replacement power costs.

Q Okay. But your -- your group would have been responsible for calculating that $10.9 million?

A Supporting the calculation of that, the -- we have a separate group that runs our dispatching that would have kind of redispatched the system, if you will, for the with Bartow.

Q Okay. I got you.

But it's safe to say, is it not, that in submitting testimony in 2017 -- and you submitted testimony in the fuel docket in 2017, '18, '19 as well as this year, right?

A That's correct.

Q Okay. So is it fair to say that you were aware in 2017 of the potential for dispute regarding that $10.9 million?

A The -- yeah, the amount -- well, we had the stipulation in 2017, and then that moved it to the next year's docket.

Q Okay. And so you were aware of the dispute of those dollars, and the response, as reflected in the stipulation, was to reflect that amount in your over/under reconciliation account, right?
A Yes, sir.
Q Okay. And then in the following year, you provided actual and estimated reconciliation updates that carried that 10 million -- or $10.9 million forward, so you effectively recovered those dollars in 20 -- in the 2020 factor, right?
A 2019 factor, I believe.
Q 2019 factor, yes.
Okay. Now, in developing the actual and estimated for 2017, were you aware that when the unit went back into service in May of 2017, that it went back into service in a derated condition?
A I am not a operations person, as I said, Mr. Brew. I am -- I am not familiar with the derating or -- or regular rating of a unit.
Q You just got the fuel costs?
A Yeah -- yes, either the actual or the projected fuel costs.
Q Okay. And at what point were you aware of any issues regarding a dispute regarding the replacement fuel costs associated with the derate of Bartow?

A I didn't, because that has not been addressed as part of, I believe as part of any of my testimonies.

Q Okay. I so you are not aware of any testimony in the fuel docket outside of the what was addressed in the proceeding referred to -- referred to DOAH that covers the derating -- the prudence of the derating fuel -- replacement fuel costs, is that right?

A I believe the only -- the only costs that I have addressed in my testimony were the -- were the what we called the 10.9 million just a few moments ago --

Q Right.

A -- that I speak with Mr. Rehwinkel from the 2017 prehearing order.

Q Okay. So your testimony in these years has never discussed or addressed specifically the replacement fuel costs associated with the derating because you had no -- no knowledge or reason to make an adjustment?

A I have -- I have not addressed those -- I have not addressed that issue in my testimony.

Q Okay. For your testimony this year, which would have included the actual update for 2019, right?

A Yes, sir, the -- no, the final true-up for 2019.

Q Final true-up for 2019. And at that time,

were you aware of the proceeding regarding the Bartow outage that was occurring at DOAH?

A I was aware the matter was referred. I believe it was referred in the -- in the preceding year's docket.

Q And so in your final true-up of 2019, you, again just to be clear, you didn't address the replacement fuel costs associated with the derated condition of Bartow, which continued through much of 2019, is that right?

A I don't addressed the actual fuel costs for 2019 in the final true-up.

MR. BREW: Okay. Thank you, that's all I have.

CHAIRMAN CLARK: Thank you, Mr. Brew.

All right. Staff, questions, Ms. Brownless?

MS. BROWNLESS: Mr. Brew has wonderfully asked the questions that I would have. I appreciate it, Mr. Brew, and I have no further questions.

CHAIRMAN CLARK: All right. Thank you very much.

All right. Commissioners, any questions? No questions from any Commissioner.

Commissioner Polmann, you were --

COMMISSIONER POLMANN: Yes, I --

CHAIRMAN CLARK: You are recognized.

COMMISSIONER POLMANN: I had a few questions. Yes. Thank you, sir.

Good afternoon, Mr. Menendez.

THE WITNESS: Good afternoon, Commissioner Polmann.

COMMISSIONER POLMANN: I am trying to, and maybe it's -- maybe it's just the circumstance under which we find ourselves here. I am trying to get some clarification without getting into things that I should not.

Is it one of your responsibilities in your work to seek recovery of the sum total cost without regard to what was the cause of the need, but the sum total cost for replacement power?

THE WITNESS: I guess I would say, Commissioner Polmann, the -- we include the actual -- for the years for the months that are actual -- the actual incurred fuel costs, as well as the projected fuel costs for any of the projected period for the fuel clause, we include the totality of those costs.

COMMISSIONER POLMANN: And I do appreciate, and I think I understand the actual, the projected and the true-up, so when I speak in terms of the replacement, I recognize those distinctions as they relate to, you know, the current year, the prior year and the future years, so if we can just accept that for the moment.

The distinction I am trying to make is -- or the question -- the next question that I would have, and maybe it would clarify what I am trying to get to is, do you, in your responsibility and those who report to you, do you make a distinction at all about underlying causes or the need for replacement power and, therefore, the fuel costs associated with that, do you make a distinction on the cause of the need?

THE WITNESS: I apologize, Commissioner Polmann, I am afraid I don't quite understand the -- what you are referring to as the cause of need. Is it the cause of the replacement power?

COMMISSIONER POLMANN: Yes. Maybe you can clarify it for me. When the utility has a need to -- has a cost associated with replacement power, presumably there is some -- some reason why they are replacement-ing power.

Are you concerned at all about why the utility needs replacement power, what would be the cause of that need, do you -- do you dis spinning wish the various causes that would lead to the need for replacement power?

THE WITNESS: It's a -- I would say it's a situation -- a circumstance by circumstance, case-by-case basis. The replacement power costs are simply the actual fuel costs incurred. So once the fuel costs are incurred, those are simply the fuel costs, or, you know, purchase power costs that we incur to serve customers over a set period of time. You know, if a unit was or was not available during that time period, the actual cost would reflect the various unit availabilities.

So from a -- your -- to -- maybe -- and I apologize if I am not getting at your -- your question, Commissioner, but I would say the -- the circumstance or the -- the -- of the outage is something that would be potentially reviewed, you know, but the replacement power costs themselves are simply the fuel or the purchase power costs that were incurred in the service of customers over a period of time.

COMMISSIONER POLMANN: Okay. Well, thank you. Let me see if I can narrow that down.

My question is in context of your responsibilities, and I understand -- my premise is that the utility has a need for replacement power from time to time, and incurs a cost for that replacement power, and your responsibility -- let me ask the question: Is you are responsibility associated with the cost for the replacement power only, or are you also -- do you have any responsibility related to the cause, or the reason for the need of the replacement power?

THE WITNESS: I -- I understand, Commissioner Polmann. I apologize for not getting that sooner.

COMMISSIONER POLMANN: It was a poorly worded question, sir. I am sorry, go ahead.

THE WITNESS: I was overseeing the costs and the -- and specifically the inclusion of that cost in the various fuel schedules. As far as a assessment of the cause, that is not my area. I would not be involved in those determinations.

COMMISSIONER POLMANN: So your responsibility is to account for the costs associated with the need for power, but your responsibility does not include an evaluation, or an underlying cause of a need for power; is that correct?

THE WITNESS: Yes, sir. That is correct.

COMMISSIONER POLMANN: Thank you.

Are you -- are you knowledgeable of the

standard utility industry practice on making the distinction as to cause for needing replacement power, or is that just -- is that something you are knowledgeable about at all about how the industry does this analysis of cause?

THE WITNESS: No, sir, I don't believe that is my area.

COMMISSIONER POLMANN: Okay. Are you knowledgeable of standard accounting requirements for making that distinction of cause?

THE WITNESS: Yes, sir.

COMMISSIONER POLMANN: Now, is that -- let me rephrase it.

Is accounting play into the distinction in cause, and is that something that you are knowledgeable about?

THE WITNESS: I -- I am -- my previous response was of accounting for the replacement power. So if I misunderstood and misstated in my earlier response, I do apologize, Commissioner Polmann.

I am not a part of -- the area of the determination of the cause is not my area. It is not an area with which I am familiar in making those determinations. So I -- I am not sure that I can -- I can answer that second part of the question.

COMMISSIONER POLMANN: Okay. Mr. Chairman, I just got a couple of more clarifying questions here.

Mr. Menendez, is it -- is it your position, then, here, and in your testimony, that you are following the standard utility industry practice in seeking replacement fuel costs, or replacement power costs following what you would describe as standard industry practice, is there anything extraordinary about what you believe you are doing, or are you following standard industry practice? It's a general question.

THE WITNESS: No, sir. I believe we are following the process.

COMMISSIONER POLMANN: And my last question, then, is is it your position, or the utility's position, your position as representing the utility on this issue, is it your position that the underlying cause, the material cause for the need for replacement power and, therefore, the costs that you are seeking recovery, is the underlying material cause for the replacement power a factor in determining the allowance for the cause -- the allowance for the cost recovery -- I am sorry, do I need to restate that?

THE WITNESS: If I wouldn't mind, Commissioner Polmann, please.

COMMISSIONER POLMANN: I will just read it the way I have written it.

Is it your position that the underlying cause for replacement power is not a factor for allowing cost recovery?

THE WITNESS: Commissioner, I -- I apologize. We -- you are asking if the -- the underlying cause has no bearing on the recovery?

COMMISSIONER POLMANN: It's a very, very pointed question. And what -- what I have been trying to get to -- what I am trying to get to is you are seeking cost recovery in your responsibilities, cost recovery for replacement fuel, it's a replacement fuel associated with replacement power, and so forth, within the utility operation, there is some reason for this. I understand you are not responsible for the operating factors.

Is it your position that the cause for the need of the recovery is separate and distinct for the allowance, that the cause is not really a factor in approving the cost recovery. There is a need for the recovery, and it is what it is, and the cause is a separate assessment? The question is whether you have a position on it or not.

THE WITNESS: Yes, sir. The -- respectfully, the company's position is the unit was operated prudently, and the costs are prudently recovered.

I don't know if that gets to your -- your answer. I do apologize, Commissioner Polmann.

COMMISSIONER POLMANN: No, that's fine. I am just asking if you have, you know, if you have a position. If you don't have a position, that's -- my question is do you have a position, is it your position this or that? And if you have no position, then I think you are answering the question. I am not asking you to restate what was -- what you stated, or what the -- what was stated at hearing.

THE WITNESS: Understood --

CHAIRMAN CLARK: We are -- Commissioner Polmann, let me --

COMMISSIONER POLMANN: I apologize --

CHAIRMAN CLARK: We are having -- we are still having a little bit of trouble understanding. I think you are breaking up some, is that right, Mike? I can see you talking but I can't hear you, and it's kind of cutting out. I think that may be -- may be causing Mr. Menendez a little bit of problem in understanding the question. And if you don't mind, I will -- I will redirect a question that might kind of help out a little bit here.

When you are -- when you are calculating the fuel cost at the end of the year, and you look back and see what went into those costs, do you have a specific category, or do you categorize that you purchased power, or you had to buy additional fuel because of something that happened; do you classify or look at that when you look back at your fuel costs for the year?

THE WITNESS: No, sir. We just have the actual fuel costs that were incurred.

CHAIRMAN CLARK: And in helping to understand how replacement power works in these cases, I assume that you are operating through a reserve system where you have reserves, if a unit were to go out and that unit had X fuel costs, and you had to bring on or use a unit that had X plus one fuel cost, at the end of the month or the year when you calculated that, your fuel costs would not be reflected as because of a certain instance, but

simply because there was additional fuel used
during that time period; is that a fair statement?
THE WITNESS: Yes, it would be -- it would be the actual cost of the unities that were actually used to serve the customers.
CHAIRMAN CLARK: And the same would go if that power were purchased, it would be purchased on kind of a spot market in realtime, and that would just be additional purchase power costs that you would have during those time periods?
THE WITNESS: Yes, sir, generated or purchased would be the same.
CHAIRMAN CLARK: But those would not be attributed, or calculated, or recorded, if you will, as we bought this additional power because of this when it came to your fuel cost analysis at the end of the year, right?
THE WITNESS: No, sir. It would simply be just all -- all the costs would typically be the actual costs.
CHAIRMAN CLARK: Okay. That's some of the -- that's kind of the question I heard Commissioner Polmann framing. I hope I may have helped a little bit there, Commissioner Polmann.
COMMISSIONER POLMANN: Thank you, Mr.

Chairman. That certainly was the direction I was going in. My apologies for being awkward there.

CHAIRMAN CLARK: No problem. No problem.

COMMISSIONER POLMANN: That covers my issue. Thank you, sir.

CHAIRMAN CLARK: All right. Commissioners, other questions?

COMMISSIONER POLMANN: Thank you, Mr. Menendez, that's all I have, sir.

CHAIRMAN CLARK: Thank you, sir.

Any of the Commissioners have questions?

All right. Seeing none, Mr. Bernier, redirect?

MR. BERNIER: Yes, sir, just very, very briefly, if I may. Sir, one redirect, is that okay?

CHAIRMAN CLARK: Yes, I am sorry. I am sorry. I am having some hearing problems here.

MR. BERNIER: Thank you very much.

FURTHER EXAMINATION

BY MR. BERNIER:

Q Mr. Menendez, if the Bartow order is sustained on appeal, how would DEF ultimately provide the refund of approximately 16.1 -- $16.1 million to its customers?

A Excuse me. It is a refund. It would be provided through lower fuel rates.

Q Okay. Thank you.

MR. BERNIER: That's all I have, Mr. Chairman.

CHAIRMAN CLARK: All right. Mr. Bernier, would you like to move your exhibits?

MR. BERNIER: Very much. Thank you.

I would move Exhibits 2 through 7 with the revisions that Mr. Menendez outlined at the outset of his testimony into the record.

CHAIRMAN CLARK: All right. Without objections, those are moved into the record.

(Whereupon, Exhibit Nos. 2 - 7 were received into evidence.)

CHAIRMAN CLARK: Are there any other exhibits, Ms. Brownless, that I have overlooked from any of the other parties? All right. That takes care of all of those.

I believe that is all for Mr. Menendez.

Would you like to excuse your witness, Mr. Bernier?

MR. BERNIER: Very much. May he be excused?

CHAIRMAN CLARK: Yes. Mr. Menendez, you are excused. Thank you very much.

THE WITNESS: Thank you, Mr. Chairman. Thank you, Commissioners.

(Witness excused.)

CHAIRMAN CLARK: All right. Next on the agenda we have Ms. Montana, I believe Mr. Coffey, am I pronouncing that correctly? Mr. Coffey is your witness?

MS. MONCADA: Mr. Coffey.

CHAIRMAN CLARK: Coffey, okay.

MS. MONCADA: Like the drink.

CHAIRMAN CLARK: All right.

MS. MONCADA: Yes. FPL calls Robert Coffey.

CHAIRMAN CLARK: All right. Mr. Coffey, would you raise your right hand and repeat after me.

Whereupon,

ROBERT COFFEY

was called as a witness, having been first duly sworn to speak the truth, the whole truth, and nothing but the truth, was examined and testified as follows:

THE WITNESS: I do. Yes.

CHAIRMAN CLARK: Thank you very much.

Ms. Moncada.

MS. MONCADA: Thank you.

EXAMINATION

BY MS. MONCADA:

Q Good afternoon, Mr. Coffey. You have just been sworn.

Could you please state your name and business address for the record?

A My name is Robert Coffey. My business address is 15430 Endeavor Drive, Jupiter, Florida.

Q By what company are you employed, and in what capacity?

A Florida Power & Light. I am the Vice-President of nuclear for Florida Power & Light.

Q Did you prepare and cause to be filed six pages of prepared testimony on July 27th, 2020?

A Yes, I did.

Q Do you have any changes or revisions to that prepared testimony?

A No, I do not.

Q If I asked you the same questions today that are contained in that testimony, would your answers be the same?

A Yes, they would.

MS. MONCADA: Mr. Chairman, I would ask that Mr. Coffey's July 27 testimony be inserted into the record as though read.

CHAIRMAN CLARK: All right. So ordered.

MS. MONCADA: Thank you.

(Whereupon, prefiled direct testimony of Robert Coffey was inserted.)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF ROBERT COFFEY

DOCKET NO. 20200001-EI

JULY 27, 2020

Q. Please state your name and address.

A. My name is Robert Coffey. My business address is 15430 Endeavor Drive, Jupiter, FL 33478.

Q. By whom are you employed and what is your position?

A. I am employed by Florida Power & Light Company ("FPL") as Vice President, Nuclear in the Nuclear Business Unit.

Q. Please describe your duties and responsibilities.

A. I am responsible for the Nuclear fleet functional areas of Engineering, Operations, Maintenance, Chemistry, Radiation Protection, Regulatory Affairs, Security, Training, Outages and Projects.

Q. Please describe your educational background and business experience in the nuclear industry.

A. I hold a Doctorate of Management in Organizational Leadership from the University of Phoenix, Masters of Business Administration degree from Regis University, and a Bachelor of Science degree in Nuclear Engineering Technology from Thomas Edison State College. I also earned a Senior Reactor Operator Management Certification at the Turkey Point Nuclear Power Plant.

I have spent 38 years in the nuclear industry, beginning in the United States Navy Nuclear Submarine Force where I served more than 20 years. I joined FPL in 2003 and held numerous positions of increasing responsibility including Maintenance Director and Work Control Manager at Turkey Point and Plant General Manager at St. Lucie. I was also the Site Vice President of NextEra Energy's Point Beach Nuclear Plant and Vice President of the Southern Region for St. Lucie and Turkey Point before serving in my current role as Vice President, Nuclear.

Q. What is the purpose of your testimony?

A. My testimony discusses the unplanned outage at St. Lucie Unit 1 in April 2019.

Q. Please describe the unplanned outage that occurred in April 2019.

A. In April 2019, St. Lucie Unit 1 automatically shut down in response to a generator ground fault. FPL's response to the unplanned outage was appropriate and efficient, and the unit was returned to service safely.

Q. Please describe the circumstances related to the St. Lucie Unit 1 generator ground fault.

A. During plant operations, St. Lucie Unit 1 automatically shut down due to a generator ground fault. FPL determined the ground fault was attributed to an insulation fault located in stator bar B17. The cause of the insulation fault was investigated but could not be definitively confirmed. Based on the location of the insulation, FPL believes the mechanism that produced the fault was introduced in the stator during a generator rewind performed by Siemens Energy Incorporated ("Siemens") in 2012 and degraded the insulation gradually over the course of seven years in service.

Q. What corrective actions were initiated to address this event?

A. After inspections and testing were conducted, FPL and Siemens determined a full rewind of the generator was the best course of action to take in order to achieve maximum reliability of the generator and the safest and most efficient return to service possible. After the completion of the rewind, High Potential Testing was conducted to ensure satisfactory results.

Q. Following the St. Lucie Unit 1 generator ground fault, did FPL perform an extent of condition review on St. Lucie Unit 2?

A. Yes. FPL performed an extent of condition review of the Unit 2 generator maintenance history and determined a similar ground fault was not present.

Q. What did the investigation of the St. Lucie Unit 1 generator ground fault find?

A. FPL's investigation ruled out many potential causes, but three possible causes hypothesized were neither refuted nor adequately supported: (1) a ferromagnetic particle introduced during installation of the stator bar in 2012, (2) impact damage during handling or installation of the stator bar in 2012 or (3) a contaminant or small object introduced in the stator bar insulation during its manufacture or construction.

Q. Explain why the location of the insulation indicates the fault mechanism was introduced during the 2012 rewind.

A. The fault is located in the end-winding area of the stator where the windings are secured using an epoxy rich banding material. The epoxy is cured during the winding installation process to produce a solid support structure. The fault occurred at a location under the cured epoxy banding material. The banding material itself was intact and undamaged. Any postulated puncture or impact to the bar occurring after the 2012 rewind would have resulted in damage to the banding material, however no damage to the banding was evident. Any postulated contaminant or particle affecting the insulation would require some path for its introduction to this specific area after the 2012 rewind. As the banding material was fully cured and intact there is no path for the introduction of a contaminant or particulate to this location in the stator windings, and no surrounding areas of the windings adjacent to the banding were affected

Q. Did FPL and Siemens follow established industry standards during the original generator rewind in 2012?

A. Yes. FPL and Siemens followed the established industry standards for insulation testing from the Institute of Electrical and Electronics Engineers (IEEE Standard 95 "IEEE Recommended Practice for Insulation Testing of AC Electric Machinery (2300V and above) with High Direct Voltage"). They also followed the established industry standards for insulation for acceptance testing, which is used to ensure equipment is operating as designed, from the American National Standards Institute (ANSI C50.10 – 1990 "Rotating Electrical Machinery – Synchronous Machines") during the original generator rewind. Additionally, contract requirements with Siemens for quality assurance were imposed in accordance with industry standards. These included expectations for inspection, testing, packaging, shipping, nonconformance process, customer communication and facilities access for mutually agreed upon witness points.

Q. Were periodic inspections performed on the Unit 1 generator following the 2012 generator rewind?

A. Yes. The type and frequency of inspections performed on the generator since the rewind adhere to standard industry practice and manufacturing recommendations. Generator inspections were performed by Siemens during every refueling outage since the rewind was completed in 2012. Additionally, generator temperature instruments were replaced during a 2013 refueling outage. Subsequent over-voltage testing was completed after the replacement with no issues. In 2016, a ground condition was detected during outage inspection activities. The ground was outside the generator in the neutral ground transformer bushing. An insulation resistance test was performed on the generator separated from the neutral grounding transformer with satisfactory results. The transformer bushing was repaired and a subsequent test was performed after reconnection to the generator with satisfactory results. Neither of these activities are related to the ground fault in 2019.

Q. How many days was St. Lucie Unit 1 out of service due to this event?

A. FPL moved quickly to restore the unit to service safely and was able to keep the outage to approximately 57 days. Notably, the Siemens generator rewind was conducted safely and more quickly than any similar unscheduled work across the industry. Additionally, while the unit was offline, FPL was able to complete some work originally planned for the fall 2019 refueling outage, thereby reducing the fall 2019 planned outage duration by approximately two days.

Q. Has FPL filed an insurance claim for the reimbursement of costs incurred as a result of this event?

A. Yes. FPL has filed an insurance claim with Nuclear Electric Insurance Limited ("NEIL") for costs related to the full generator rewind that was performed during this outage. This claim does not include replacement fuel costs, however, because NEIL only covers replacement fuel costs when an outage surpasses 12 weeks.

Q. What is the amount of the insurance claim?

A. FPL has submitted a claim for approximately $25.9 million for expenses associated with the event. This claim amount is subject to a $10 million deductible plus a 10% quota share for any recoverable amounts plus disallowance of potential non-reimbursable expenses in accordance with the policy.

Q. What is the status of the insurance claim?

A. NEIL is currently reviewing the documentation associated with the claim amount. FPL expects a final coverage decision in the third quarter of this year.

Q. Does this conclude your testimony?

A. Yes, it does.

BY MS. MONCADA:

Q Mr. Coffey, your July 27 testimony did not include any exhibits, is that correct?

A That's correct.

Q Thank you.

Did you also file six pages of prepared testimony in this proceeding on September 3rd, 2020?

A Yes.

Q Do you have any changes or revisions to that prepared testimony?

A No.

Q If I asked you today the same questions contained in that testimony, would your answers be the same?

A Yes.

MS. MONCADA: Mr. Chairman, I would ask that Mr. Coffey's September 3rd testimony be inserted into the record as though read.

CHAIRMAN CLARK: So ordered.

(Whereupon, prefiled direct testimony of Robert Coffey was inserted.)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF ROBERT COFFEY

DOCKET NO. 20200001-EI

SEPTEMBER 3, 2020

Q. Please state your name and address.

A. My name is Robert Coffey. My business address is 15430 Endeavor Drive, Jupiter, FL 33478.

Q. By whom are you employed and what is your position?

A. I am employed by Florida Power & Light Company ("FPL") as Vice President, Nuclear in the Nuclear Business Unit.

Q. Please describe your duties and responsibilities.

A. I am responsible for the Nuclear fleet functional areas of Engineering, Operations, Maintenance, Chemistry, Radiation Protection, Regulatory Affairs, Security, Training, Outages and Projects.

Q. Please describe your educational background and business experience in the nuclear industry.

A. I hold a Doctorate of Management in Organizational Leadership from the University of Phoenix, a Masters of Business Administration degree from Regis University, and a Bachelor of Science degree in Nuclear Engineering Technology from Thomas Edison State College. I also earned a Senior Reactor Operator Management Certification at the Turkey Point Nuclear Power Plant.

I have spent 38 years in the nuclear industry, beginning in the United States Navy Nuclear Submarine Force where I served more than 20 years. I joined FPL in 2003 and held numerous positions of increasing responsibility including Maintenance Director and Work Control Manager at Turkey Point and Plant General Manager at St. Lucie. I was also the Site Vice President of NextEra Energy's Point Beach Nuclear Plant and Vice President of the Southern Region for St. Lucie and Turkey Point before serving in my current role as Vice President, Nuclear.

Q. What is the purpose of your testimony?

A. My testimony presents and explains FPL's projections of nuclear fuel costs for the thermal energy to be produced by our nuclear units measured in million British thermal units or ("MMBtu"). Nuclear fuel costs were input values to the GenTrader model that is used to calculate the costs included in the proposed fuel cost recovery factors for the period January 2021 through December 2021. I am also supporting FPL's projected 2021 incremental plant security and Fukushima-related costs. Finally, I address 2020 outage events at FPL's nuclear units.

<u>**Nuclear Fuel Costs**</u>

Q. What is the basis for FPL's projections of nuclear fuel costs?

A. FPL's nuclear fuel cost projections are developed using projected energy production at its nuclear units and current operating schedules for the period January 2021 through December 2021.

Q. Please provide FPL's projection for nuclear fuel unit costs and energy for the period January 2021 through December 2021.

A. FPL projects the nuclear units will burn 296,846,059 MMBtu of energy at a cost of $0.4955 per MMBtu for the period January 2021 through December 2021. Projections by nuclear unit and by month are listed in Appendix II, on Schedule E-4, starting on page 17, which is attached as an exhibit to FPL witness Deaton's testimony.

Nuclear Plant Incremental Security Costs

Q. What is FPL's projection of incremental security costs at its nuclear power plants for the period January 2021 through December 2021?

A. FPL projects that it will incur $34.3 million in incremental nuclear power plant security costs in 2021. The costs consist of $3.5 million of capital expenditures and $30.8 million of O&M expenses.

Q. Please provide a brief description of the items included in incremental nuclear power plant security costs.

A. The projection includes the additional costs incurred in maintaining a security force as a result of implementing the NRC's fitness-for-duty rule under 10 CFR Part 26, which strictly limits the number of hours that nuclear security personnel may work; additional personnel training; maintenance of the physical upgrades resulting from implementing the NRC's physical security rule under 10 CFR Part 73; and impacts of implementing the NRC's cyber security rule under 10 CFR Part 73. It also includes force-on-force modifications at the St. Lucie and Turkey Point nuclear sites to effectively mitigate new adversary tactics and capabilities employed by the NRC's Composite Adversary Force, as required by NRC inspection procedures.

<u>Fukushima-Related Costs</u>

Q. What is FPL's projection of Fukushima-related costs at its nuclear power plants for the period January 2021 through December 2021?

A. FPL's current projection of Fukushima-related costs for 2021 is approximately $1.3 million of O&M expenses.

Q. Please provide a brief description of the items included in this projection of Fukushima-related costs.

A. The projection includes FPL's share of costs incurred for equipment, storage, and transportation, to support the shared Regional Response Centers, a warehouse of off-site portable equipment shared by the industry.

<u>2020 Unplanned Outage Events</u>

Q. Has FPL experienced any unplanned outages at any of its nuclear plants in 2020?

A. Yes. In March 2020, St. Lucie Unit 2 experienced a delay in return to service following the refueling outage associated with the planned replacement of a 6900 volt electrical switchgear required for plant operation; in July 2020, Turkey Point Unit 4 shut down due to a main generator lock out from a loss of exciter ; and in August 2020, Turkey Point Unit 3 shut down in response to rising steam generator levels. FPL's response to each unplanned outage was appropriate and efficient, and the units were returned to service safely.

Q. Please describe the circumstances related to the St. Lucie Unit 2 switchgear replacement modification.

A. During the Spring 2020 outage, FPL performed a planned replacement of a 6900 volt electrical switchgear required for plant operation. An interfacing equipment configuration conflict was discovered during project implementation. Additional work scope and increased implementation duration was required to address the discovered condition.

Q. What corrective actions have been initiated to address this event?

A. The interface configuration conflict was resolved during the refueling outage and no further technical corrective action is required. Other corrective actions were implemented to improve administrative processes associated with design engineering function collaboration, communication, and oversight.

Q. How many days was the St. Lucie Unit 2 outage delayed due to this event?

A. The Unit 2 outage delay due to 6900 volt electrical switchgear replacement modification was approximately 2 days.

Q. Please describe the circumstances related to a main generator lock out from a loss of exciter that impacted Turkey Point Unit 4.

A. In July 2020, Turkey Point Unit 4 automatically shut down due to an electrical trip of the main generator caused by loss of excitation. FPL determined the Permanent Magnet Generator ("PMG") malfunctioned.

Q. What corrective actions have been initiated to address this event?

A. FPL replaced the PMG with a spare. FPL is currently in the process of investigating and evaluating this outage.

Q. How many days was Turkey Point Unit 4 out of service due to this event?

A. The Unit 4 outage due to a main generator lock out from a loss of exciter was approximately 15 days.

Q. Please describe the circumstances related to a rise in steam generator levels that impacted Turkey Point Unit 3.

A. In August 2020, a control valve at Turkey Point Unit 3 unexpectedly opened, which caused a turbine load reduction. This sequence of events led to a rise in steam generator levels, and a manual reactor trip was performed in accordance with plant procedures. During startup from this outage, the reactor protection system automatically shut the reactor down when an instrument sensed higher than expected neutron flux in the reactor. While in power ascension from this outage, the unit was manually shut down due to steam generator water level control issues that resulted in the operating steam generator feed pump tripping on low suction pressure. The trip occurred due to abnormal valve alignment on the steam generator feed pumps. This valve alignment was restored to normal.

Q. What corrective actions have been initiated to address these events?

A. FPL performed the necessary repairs to return the unit back online. FPL is currently in the process of investigating and evaluating this outage.

Q. How many days was Turkey Point Unit 3 out of service due to these events?

A. The Unit 3 outage due to these events was approximately 6 days.

Q. Does this conclude your testimony?

A. Yes, it does.

BY MS. MONCADA:

Q Mr. Coffey, your September 3rd testimony as well did not include any exhibits, is that right?

A That's correct.

Q Thank you.

Did you prepare a summary of your July and September testimonies?

A I did. Yes.

Q Could you please provide that summary to the Commission?

A Yes.

Good afternoon Commissioners. My testimony discussed an unplanned outage and an outage extension in April 2019 and March 2020. For both events the appropriate actions were taken --

CHAIRMAN CLARK: Mr. Coffey, one moment --

THE WITNESS: -- units were restored and --

CHAIRMAN CLARK: Mr. Coffey --

THE WITNESS: -- in April 2019, St. Lucie Unit 1 automatically shut down in response to a generator ground fault. The ground fault was attributed to an insulation defect located in a stator bar; however, the exact cause could not be definitively confirmed. The three possible causes were: Contaminants introduced during original manufacturing, a particle introduced during installation in 2012, or impact damage during handling installation in 2012. All three potential causes would have gradually degraded insulation over the course over the next seven years.

We know it to be manufacturing or installation issue because any other defect would require a path for its introduction. In this case, a path did not exist because the fault was located beneath the epoxy banding material that was installed during original installation. The material was intact and undamaged.

Subsequently, it was determined a full rewind of the generator was the best course of action to achieve maximum reliability. Leading up to the 2012 generator rewind, FPL and Siemens followed all established industry standards for testing.

Additionally, contract requirements for quality assurance were imposed in accordance with industry standards and included mutually agreed upon witness points.

Periodic inspections were also performed on the Unit 1 generator in every outage since the 2012 generator rewind. The type and frequency of these inspections adhered to standard industry practice and manufacturing recommendations.

Following the generator fault in 2019, FPL moved quickly to restore the unit to service safely, and was able to complete the outage in 57 days. This duration was more expeditious than any similar unplanned rewind performed in the industry.

Additionally, while the unit was off-line, FPL was able to complete some work originally planned for the fall 2019 refueling outage, thereby reducing that outage duration by approximately two days.

In March 2020, St. Lucie Unit 2 experienced a delay in return-to-service during the refueling outage. This was the result of a planned replacement of a 6900-volt electrical switchgear required for plant operation. An equipment configuration conflict was discovered during project implementation. The configuration issue required additional time to address the needed change. The technical cause of the return-to-service delay was resolved during that refueling outage, and no further technical corrective action was required.

In summary, FPL's actions for both events were appropriate and reasonable.

Thank you very much for your time. This concludes my summary.

CHAIRMAN CLARK: Ms. Moncada.

MS. MONCADA: Thank you, Mr. Chairman. Mr. Coffey is available for cross.

CHAIRMAN CLARK: All right. Thank you.

Mr. Coffey, we had a little bit of trouble. You are breaking up some. I don't know what the cause is there, but we were having a little bit of trouble hearing the first part of your summary there, so be cognizant, we may have to stop you and get you to clarify for us.

All right. With that, Mr. Rehwinkel, it's your witness.

MR. REHWINKEL: Thank you, Mr. Chairman.

Good afternoon, Mr. Coffey.

THE WITNESS: Good afternoon, Mr. Rehwinkel.

MR. REHWINKEL: Mr. Chairman, before we get under way, I just want to state for the record, in the Prehearing Order, there is a, I will call it an embargo requirement on exhibits used in cross-examination, and I just want to state for the record that we lifted that embargo, if you will, as to the company, and so if Mr. Coffey has exhibits with him, I don't want anybody to think that it was because the company was in violation of that requirement.

And in that regard, I would like to just ask Mr. Coffey if you have Exhibits 2 through 9 available to you?

THE WITNESS: I do have Exhibits 2 through 9 available to me.

MR. REHWINKEL: Okay. Thank you very much.

CHAIRMAN CLARK: Thank you, Mr. Rehwinkel.

BY MR. REHWINKEL:

Q   If you could tell me what is your functional area of responsibility just briefly?

A   Yes, Mr. Rehwinkel. My functional area of responsibility is I am the Vice-President of Nuclear at Florida Power & Light corporate offices, and so I am -- I am the executive over governance and oversight operations of our nuclear -- nuclear operating units.

Q   Is that the four units in Florida, or does it include Point Beach, Duane Arnold and Seabrook?

A   It is -- yes, it is the four units in Florida, and it is also Point Beach and Seabrook, Duane Arnold has recently gone into decommissioning.

Q   Okay. You state that you have an engineering responsibility in that area. Does that include the -- what's known as the Engineering Operation Support

Services, EOSS?

A It is -- yes, it is, Mr. Rehwinkel.

Q Okay. And outages and projects, is that -- is that a reference to planned outages, or does it incur -- does it encompass forced or unplanned outages as well?

A It encompasses both planned outages and forced outages as far as the governance and oversight of those activities. And then I also have the project organization reports through me, and so major projects I direct oversight of, as well as governance and oversight.

Q Okay. So an uprate would be an example of a project, a very large project that you would be responsible for --

A Yes, that's --

Q -- in your job --

A Yes, that's correct.

Q Okay. Now, in your background, just for the context of our discussion and cross-examination today, you are a nuclear engineer, is that correct?

A That's -- yes, that's correct.

Q That's both by education and training --

A Yes, that's --

Q -- is that right?

A Yes, that's correct.

Q And I noticed that you were in the Nuclear Navy. I think you started there in around 1983, is that right?

A Yes. Yes, 1982 until 2003.

Q Okay. So you started the year that Hyman Rickover retired, but you were in the organization that he built, and for which his principles were carried forward, is that right?

A Yes, that's absolutely correct.

Q Okay. And that's a source of pride for you, is that right?

A Yes, that's right.

Q Okay. There was a noted culture of integrity and safety in that Rickover established Nuclear Navy, is that right?

A Yes, that's absolutely correct.

Q It's world famous, and when compared to other navies, it was beyond compare, is that right?

A That was my -- that was my belief, yes, that's correct. I don't have knowledge of the other navies, but I believe that to be true.

Q Sure. And as plant general manager, was that of both the St. Lucie units?

A I was the plant manager from 2012 to 2016 at the St. Lucie units, yes.

Q Okay. That's -- you are more like the site general manager because you cover both 1 and 2?

A Yes. I was the site general manager of Units opinion and Units 2 from the tail end of 2012 until 2016 when I moved on to Point Beach.

Q Okay. Now, Point Beach is a NextEra, I will call it a merchant plant, is that fair?

A Yes, that's correct.

Q Okay. And it's in Wisconsin?

A It is in Wisconsin, just south of Greenbay.

Q Okay. Now, when you were Vice-President for the Southern Region, does that, in the FPL nuclear organization, does that separate those responsibilities to just the four Florida units as compared to the -- the other units in the NextEra fleet?

A When I was the Regional Vice-President of the South, I was the executive in charge of Turkey Point and St. Lucie plants, and it was separated from the north.

Q Okay. But your responsibility now as VP Nuclear is you are responsible for both the south region and whatever the other region is, is that right?

A The governance and oversight elements of it, and the applicable portions of the support and perform activities like projects, that's right.

Q Okay. Now, I notice in your testimony you

said that when -- when you were in Turkey Point, you received a senior reactor operator license, is that right?

A That is correct. Not license, so that's partially correct. I received a senior management certification. I did not go to the 18-month license class. It was a compressed management certification class for five months.

Q Okay. So you were an operator, but you don't hold a license as the NRC understands it, is that right?

A I was operator for 21 years in the Nuclear Navy, and then I was -- I predominantly specialized in maintenance and engineering on the non-Navy side of the house. But operations is something that I have grown up with and been a part of for 35 -- almost 35 years in nuclear now.

Q Okay. The reference to -- I just -- I want to understand, if you give me a moment.

So the senior reactor operator management certification -- and I know I misstated that by saying license, your testimony says certification -- is that still in -- do you still hold that certification?

A I do. Yes. I did -- I went to that class. I took those examinations. I tested on that simulator, and I still hold that certification.

To meet the minimum qualifications to be a plant manager, you either have to have been previously licensed or have gone through a management certification class that gives you the equivalent schooling and practice and technical abilities to be able to do it, and I did the latter.

Q Okay. So you generally -- well, you have the requisite familiarity with NRC requirements with respect to the operations of a licensed facility, is that correct?

A Absolutely, on multiple different units.

Q Okay. I want to spend most of the time today talking to you about your July 27th, 2020, testimony, so if you have that with you.

A Just one second. Okay, I have that with me. It's open.

Q Okay. Now, this testimony is the testimony you submitted in this docket that addresses the April 25th, 2019, through June 21, 2019, forced outage at Plant St. Lucie Unit 2, is that right?

A Unit 1, sir.

Q Unit 1?

A Yes, sir.

Q Is there a difference in your mind as to an unplanned outage versus a forced outage? Are they one

in the same or is there a different?
A Forced outage and unplanned outage is of the same.
Q Okay. Do you call the St. Lucie Unit 1, do you sometimes call it PSL 1?
A We do. We call it PSL 1.
Q Okay. So if I say PSL 1 in my questions, we know I mean plant -- St. Lucie Plant Unit 1 --
A Yes, that's correct.
Q -- and PSL 2 would be Unit 2, right?
A Yes, that's correct.
Q Okay. And then if we go to page two of your -- your testimony, lines eight and nine. You state the purpose of your testimony as: My testimony discusses the unplanned outage at St. Lucie Unit 1 in April 2019, is that right?
A Yes, sir.
Q Okay. And in that discussion, as you put it, that discussion, as you -- as you refer to it, continues on through page six, line 12, is that right?
A Let me make sure -- that's correct. Yes.
Q Okay. And I apologize. I said I was going to refer to this. I need to take a little detour and go to your September 3rd testimony if we can just for a second.

A Okay. I am there, sir.

Q All right. In that testimony, on page four, beginning on line 12, through the remainder of that testimony on page six, this is your testimony where you discuss other unplanned outages at St. Lucie Unit 2 and Turkey Point Units 3 and 4; is that right?

A Yes.

Q Okay. And just to be clear, the September 3rd testimony does not in any way discuss the April 29 St. Lucie Unit 1 forced outage, does it?

A It does not.

Q Okay. And I think, as your counsel indicated, there is no exhibit to either of your testimonies, the 27th of July or the 3rd of September, is that right?

A That's right.

Q So the sole evidence that you are presenting today in this hearing is confined to the testimony on -- in your July 27th testimony with regard to the April 2019 forced outage at PSL 1, is that right?

A No. It was on the Unit 1 generator outage in April, but it was also on the delay in return-to-service that's on page four of the September testimony for the delay in return to service on Unit 2 for the switchgear delay.

Q Okay. I probably didn't ask that question

right.

What I was trying to make sure the record is clear on is -- let me ask it this way: With respect to the PSL 1, April 2019 outage, the evidence that you are presenting to the Commission is confined to your July 27th, 2020, prefiled testimony; is that right?

A   Yeah, I am sorry. I misunderstood the previous question. Yes, that's correct.

Q   I don't think I asked it the right way.

And so as far as your prefiled testimony, it's confined to that, and then whatever else you testify to today, right?

A   Correct.

Q   All right. If you know, when a utility like FPL has an un -- has an unplanned outage, you incur replacement power costs, is that correct?

A   Yes, that's correct.

Q   Okay. In addition to replacement power costs, you would also agree that there may be extra O&M and capital costs related to an unplanned outage; is that right?

A   Yes, that's right.

Q   Okay. On your July 27th testimony at page two, can you read for me the response to the question -- read aloud for me the response to the question that is

on page -- on line 10?

A On line 10, okay.

Q You can read the question, too.

A Please describe the unplanned outage that occurred in April 2019.

In April 2019, St. Lucie Unit 1 automatically shut down in response to a generator ground fault. FPL's response to the unplanned outage was appropriate and efficient, and the unit was returned to service safely.

MR. REHWINKEL: Okay. Before we proceed on, Mr. Chairman, I am not having trouble hearing Mr. Coffey, but when he was reading that answer, it seemed to me there -- a little bit of garbling in there, and I just wanted to make sure that it wasn't reflected that way in the hearing room or the court reporter.

CHAIRMAN CLARK: It sounded good here. The court reporter, did you get all of it?

COURT REPORTER: Yes, sir, I did.

CHAIRMAN CLARK: We're all clear.

MR. REHWINKEL: I just was just checking because it -- the quality vacillated a little bit on my end.

CHAIRMAN CLARK: No problem.

BY MR. REHWINKEL:

Q Okay. Can you tell me your definition of the phrase appropriate and efficient as you use it in that answer?

A Yeah. So the way I would characterize that, Mr. Rehwinkel, is that we took the time that we needed to troubleshoot and investigate the cause of that ground fault, and then we put a plan together to resolve that issue using the appropriate decision-making processes that we have in nuclear. Then we constructed a schedule and determined who we would select to do that work, and we conducted that work in a manner which we believe was safe and efficient, and then we restored the generator service. And I could back that up with several facts that we learned throughout the process of the root cause and such, but I will wait for your questions.

Q Okay. Thank you.

And just so I understand, this answer here is directed at what happened when the outage was discovered. It doesn't address anything that happened before the ground fault tripped the unit, is that right?

A That's right.

Q Okay. And the -- the -- would it be fair to say that the response that you describe in your testimony here is the sum of the actions that FPL

nuclear organization, in general, and the St. Lucie station personnel specifically took to address the outage?

A   Yes, I would say that's a fair statement, Mr. Rehwinkel. I will tell you that when we initially filed this -- this testimony, we didn't have the input of the completed root cause on exactly why it occurred yet. So some of the information was not as descriptive as we would have liked it to be, but we didn't have the final product of the root cause completed yet. That didn't get completed and signed off until August 19th, and so we wanted to make sure we didn't put anything in the testimony that might be concluded as inaccurate.

Q   Okay. Well, as you may have guessed from the exhibits, I have some questions about some of the documents in here, and so I think we can get to that and your responses to those.

A   Thank you, sir.

Q   Okay. How many -- an outage of this type as a unit like PSL 1 is a significant matter that gets the attention of the organization, correct?

A   Absolutely. I would say that an outage of this magnitude is one of the more difficult outages without the forthought of the 18 months of planning, it's one of the more difficult ones to recover from.

Q So there are a lot of individuals from the lowest level in the organization all the way to the top, which is you, you and above, that are focused on resolving this issue; is that right?

A Yes. Absolutely.

Q Okay. If I look on page two, lines -- and starting with the question on line 14 through line 23, is it fair to say that this testimony blames Siemens for introducing the mechanism that caused the fault in the unit either before -- in or before 2012?

A I would -- I would say that we didn't go as far as to lay blame. We did go as far as to say that the root cause concluded those three causes happened while it was in the custody of Siemens to implement their portion of that contract.

Now, whether or not that occurred at the Siemens facility or with resin that was made outside of Siemens, we didn't make those conclusions, but it was within the contractual confines of Siemens to perform this work, and it was not -- it didn't -- we didn't get the results that we expected, obviously.

Q Okay. I used the word blame because that's just kind of a walking around term, but you say on line 20, FPL believes, and I believe your counsel in the opening, and you in your summary, laid the

responsibility for this -- the mechanism that caused the fault at the seat of Siemens, is that fair?

A   That's fair.

Q   Okay. Now, it states here in your testimony that FPL investigated the cause of the fault, but that, quote, it could not be definitively confirmed, is that right?

A   That's correct. Yes.

Q   Now, the investigation that is referred to in your testimony, is that essentially all of the process that led up to and includes the RCE, or the root cause -- what's the E stand for --

A   Evaluation.

Q   -- evaluation?

A   Yes. Siemens -- Siemens and Florida Power & Light both separately, us by our process, and Siemens by theirs, performed root cause evaluations. In those root cause evaluations, ours did not have Siemens as part of our team, and Siemens did not have us as part of their team, and both of those evaluations came to the same conclusions on it was one of the three things that I list in my testimony, but there was no way with the forensics evidence we have in the condition it was in we could determine which of the three was the -- was the exact cause, but we know one of those three was the cause.

Q Okay. And if I can ask, and I am not trying to -- to strike out at you in your answers, I am going to ask you questions about the FPL RCE, some people call it an RCA, root cause analysis. They are interchangeable terms, right?

A Yes, sir.

Q So if I say RCA, you will know I mean what you call an RCE, and vice-versa, right?

A Yes. Absolutely.

Q Okay. And at other thing I would ask for purposes of this, and this is just because we are dealing with confidential information, the -- the Exhibit 8 that I have asked you to look at is the FPL RCE, but it is a redacted public version; is that your understanding?

A I did not know -- I did not know that yours was a redacted public version, I probably should have, but, no, I did not know that.

Q Okay. And just -- just -- I would like to ask you if you refer to it, or answer questions from my direction to you to look at it, please use the redacted version so we can be sure that you don't verbalize any information that's not -- that's blacked out in the redacted version, is that understandable?

A Yes, that's understandable.

Q Okay. And likewise, if I could, the Siemens RCE, I think, is Exhibit 4C?

A Correct.

Q And it is confidential in its entirety?

A That's right.

Q At least that's the claim.

So what I am getting at is I would like, for purposes of logistics here, is to keep inadvertent disclosure of confidential information is to not refer to the Siemens report unless I ask you a specific question about it, if that's at all possible. I just don't want to have cross-examination and you reveal something in the cements report while trying to synthesize it with the FPL RCE; does that make sense?

A It absolutely makes sense, and I am prepared to not discuss the confidential aspects of the Siemens root cause. We don't have any confidential aspects on the -- on the FPL root cause, so I will be able to speak in that way.

Q Okay.

MR. REHWINKEL: And, Maria, I just -- I am not trying to limit your witness, I just want to be very careful, because I put -- I put several confidential exhibits out here, and I want to try to stay in the lane, if you will.

MS. MONCADA: Understood, Mr. Rehwinkel. Thank you.

MR. REHWINKEL: Okay.

MS. HELTON: Mr. Chairman, can I just -- for purposes of the record, so, Mr. Rehwinkel, were you planning on asking for your Exhibit No. 8 to be identified as Exhibit 53 for the record, and then your Exhibit 4C to be identified as Exhibit 54?

MR. REHWINKEL: Well, right now, I think -- let me see. I have -- I don't know what my first exhibit is.

I am not trying to identify them right now, Ms. Helton. I just -- I got an answer there that made me concerned because it was an answer about what Siemens and FPL came to the conclusion of. And I just wanted to make sure that we -- we kept -- kept them separated. It's my fault that I didn't make these ground rules when we first started.

MS. HELTON: Okay. I am just trying to make sure we are clearly identifying in the record what you are wanting to put in the record so we are all talking from the same page.

MR. REHWINKEL: Okay. Yeah, I am not at a point, I don't think, to -- to identify the -- the FPL RCE at this point.

BY MR. REHWINKEL:

Q Okay. Let's go to page three of your -- your July 27th testimony.

A All right.

Q And on line 18 through page four, line 21, you discuss some information related to the 2012 rewind, is that right?

A Yes, sir.

Q And this rewind was part of the uprate that was undertaken at both PSL 1 and PSL 2, is that right?

A Yes, that's correct.

Q Okay. That was not something that was under your purview at that time, is that right?

A I was -- well, yes and no is the way I will answer that, and that is I was -- I was involved with -- at the time that this was happening, I was at the Unit 3 uprate as the Maintenance Director at Turkey Point. However, our fleet, all of our fleet nuclear sites, they read the condition reports, reports that we write every day, of every one of the sites, and we all have responsibility to govern and oversee and support and perform at our own sites, as well as challenging the other three sites.

So I was not -- so I was definitely familiar with the goings on of what was going on at St. Lucie as a director at Turkey Point at the time, but I wasn't the direct -- I didn't have any direct reports that were there.

Q Okay. Thank you.

I am going to ask you a question here, and it's a long question, and if you don't understand it, either you or your counsel can say so and I will rephrase it, but I am trying to see if I understand the gist of page three, line 18 through page four, line seven.

And as I read that testimony, you summarize FPL's logical basis for concluding that the fault inducing causal mechanism had to have been introduced to the plant through the rewind work that was performed in early 2012 either as part of the manufacture or construction of the generator's stator bar 17, or during the actual on-site rewind work, both of which were performed by or through a Siemens -- through Siemens or a Siemens subcontractor?

A Yes, that's correct.

Q Okay. I believe in your summary you stated -- and it may be in your testimony as well -- that as a part of that logic, that the particle, or the fault

mechanism could not have been introduced after the completion of the uprate in 2012 because there was no path --

A Yes.

Q -- for that fault causing mechanism to be introduced into the generator, is that fair?

A Yes, and I would just expand on that a little bit. As those machines are built out during a rewind, they get disassembled down to parade rest. And then when they are built back up, the foundation iron work starts, then the coils are set in in a specific pattern. And then after that, there is banding material, insulation material that's installed and epoxyed, and that outer banding material and epoxy was undamaged, so there was no path external to that material.

Q Okay. Let me ask you, if you can, to turn to -- do you have Exhibit 7C?

A I do.

Q You know this is a confidential exhibit.

A It is.

Q And I want to ask you --

MR. REHWINKEL: Mr. Chairman, I guess I want to identify Exhibit 7C as the next exhibit.

CHAIRMAN CLARK: What's that number?

MS. BROWNLESS: It's 53.

CHAIRMAN CLARK: All right. We will mark it as Exhibit 53.

MR. REHWINKEL: Okay.

(Whereupon, Exhibit No. 53 was marked for identification.)

BY MR. REHWINKEL:

Q So I am not sure that this is an entirely relevant document. It is dated -- it's for a service event that occurred in 2018, is that right?

A Yes, that's correct. This was -- just for information, Mr. Rehwinkel, this -- this is the actual inspection on Unit 2 that occurred at its seven-year frequency that would have occurred in 2019 in the fall outage had the rewind, the emergent rewind, or the unplanned rewind not occurred. So -- and as a matter of fact, this document is what was used to confirm that there was no extended condition on Unit 2, similar to Unit 1.

Q Okay. And I want to ask you about Bates page five.

A Okay, I am there.

Q And I know this relates to Unit 2, but without -- since it's confidential, without getting into the details, you see there is some nameplate type information at the top, and then a sentence, and then

there is a -- a paragraph with some bullets and subbullets; do you see that?

A Yes.

Q Okay. Would it be fair to say that these type of activities were routine inspection activities that would -- that a main generator would undergo?

A Yes. Some of them -- some of them are activities that happen every outage, like a generator crawl-thru -- and when we say crawl-thru, we don't necessarily mean a human. There is robotics involved as well. And others of them, like the -- like the insulation testing, the high voltage insulation testing that's discussed in here are done at other intervals. Those are typically done every seven years because those are over the rate of voltage of the machine to make sure that you don't have any issues when you are doing that testing.

Q Okay. So I think you are -- you are answering the question that I want. So at Unit 1, these same type of activities would have occurred after the rewind was -- was completed, maybe not the exact same, but similar types of activities, is it that fair?

A Well, the exact same, but the answer is actually yes/no again, because some of them -- the high potential testing that I talk about, for example, the manufacturers in OEM, the original equipment manufacturer recommendations in the industry standard is to do that every seven years, and the generator crawl-thrus is every outage.

So some of them are done every outage and some of them are done at specified intervals. And the -- and the rewind was done in 2012 on Unit 1. There was a subsequent repair that was done in 2013, which had high voltage testing done, so it wasn't coming due until 2019, but we didn't get there before we conducted that high potential testing.

So -- so, yes, we were consistent on year one and two in all our units with doing the manufacturing -- manufacturer recommendations for maintenance and testing.

Q Okay. Thank you.

The high -- high potential testing, for example, that's not an invasive test, is that right?

A Well, yeah -- well, it depends on how you determine invasive.

And so these -- the generators themselves operate at 22,000 volts, and the high potential testing exposes them to 76,000 volts. So you are putting three times as much voltage on it to make sure that you are not going to have a path for current to ground, and so you don't want to do that too often because you are actually putting an overvoltage condition on the machine to make sure the windings are there.

So I would consider it invasive just because it's operating for the small period of that test above its nameplate rating.

Q Okay. Fair enough.

The crawl-thru, as you indicated -- and you anticipated by question -- it's done by a robot, not a person?

A The -- not totally. The portions that can't be done without using robotics are done with a robot. The ones that can be done with a person, they are done visually with somebody with proper lighting and magnifying materials that they use. So it's a mix depending on the inspection.

Q Okay. So what I am trying to understand here is in context of your testimony, where I asked you that question about your logic about saying it had to be Siemens, and it had to be 2012 or earlier. In contrast to the crawl-thru that would be similar type of testing, how would you have ensured that there was no path into the unit for a foreign material to be introduced in those post 2012 inspections?

A Well, I will tell you, the -- well, first off the foreign material question is a good question, because it's -- two of the three causes have something to do with foreign material, whether it's a contaminant or whether it's the magnetic termite, the small particle.

And I first start off by saying that our Florida Power & Light Foreign Material Exclusion Program, it strives to maintain perfection even though we know perfection is not -- is not something that can always be achieved. We strive for it in great detail. In our assessment of our FME program is that it's strong, because what it does, Mr. Rehwinkel, when we operate and go into these maintenance activities, it has several key elements to it. It controls the environment, up to and including atmosphere controls, barricades, watches. When I mean watches, I mean people that actually are guarding the area so no one can go into the area, and they log things in and out of those areas.

We schedule the activity such that there is clear separation between demolition activities and rebuild activities. And in between those, we insert cleaning activities, vacuum, wash, inspection activities and testing activities to make sure that those items aren't there.

Once the construction activities are completed, all the witness points are done and all the testing is done, then we maintain that FME program any time we crack the doors to go, or break barriers to go into that machine, it's called our FME a zone, high critical zone, and we maintain those strict controls when we are getting into that machine, and so the same rigor applies.

Q Okay. And just for the record, you say FME, that's foreign material exclusion, is that right?

A Yes. Yes, that's correct, foreign material exclusion. It's basically establishing a surgical room type of atmosphere.

Q Can you clear up something for me in this context? I was going to ask it later, but I will go ahead and bring it up now.

I read several places in the RCE and maybe some of the other materials that the rewind was on-site?

A Yes.

(Whereupon, the hearing room lost live videoconference connection.)

BY MR. REHWINKEL:

Q Can you educate me on that, is were there some activities that you might consider rewind that were done at a factory or fabrication place versus actually on the

PSL 1 site?

A   Yes. And so the actual coils themselves and the rewind kit is something that's built off-site at vendor facilities, and so -- and when I talk about insulation activities, Mr. Rehwinkel, some of them happen at the factory, when they do those coils and they build those coils out, and that laminated materials are those or those bindings, and they are insulated at the factory and brought to the site as a rebuild kit. Like the one we did in 2019, an entire rebuild kit was sent to the site, but that site was manufactured externally.

If by chance this contaminant was caught up in the resin of one of those items that was at the site, it took seven years for itself to work its way out of there, but it was underneath all of that banding material that I talked about.

So all of the build of the coils and the underneath, laying iron and such like that, is done external to the site, and then that comes to the site, the machine gets taken down to parade rest. And using those materials they build that machine back up again, and so that's exactly what that is.

Q   Are you saying parade rest?

A   Yeah, I probably shouldn't use a military term. You take it down to a hollow empty core of a machine.

Q Okay. I am being told my audio is down. I don't know if --

A I can hear you just fine.

Q Okay.

MS. MONCADA: I can hear you fine, Mr. Rehwinkel.

MR. REHWINKEL: I don't see the Chairman.

THE WITNESS: It looks like --

MS. MONCADA: Yeah, we lost him.

COMMISSIONER BROWN: I had a message from the Chairman, he said that the audio is paused, the meeting is paused, we lost signal, so let's just hold on a moment.

MR. REHWINKEL: Okay.

MS. MONCADA: Sure.

COMMISSIONER BROWN: Why don't we take a 10-minute recess. Let's reconvene -- just stay on, we will reconvene at 2:30.

MR. REHWINKEL: Thank you.

(Brief recess.)

CHAIRMAN CLARK: All right. We are back. Thank you all for your indulgence. Sorry about that. I appreciate everybody's indulgence.

I am not certain at what point of the audio went bad. I think y'all were continuing right along happily, and the rest of us were clueless. Mr. Rehwinkel, I will let you guess where you left off and where we need to go back to.

MR. REHWINKEL: Well, I am going to ask, just because I got a bunch of messages from people saying that they couldn't hear, but I think the discussion about the parade rest was heard in the hearing room, is that correct?

CHAIRMAN CLARK: Yeah, let's ask the court reporter, she would have been on-line.

MR. REHWINKEL: She heard everything, and she didn't know when you dropped, but I would ask -- Mr. Coffey said that the unit was taken down to parade rest. And then I asked him, did you say parade rest? And he said that it was a military term. And I was just wondering if that was heard in the hearing room. I am just trying to get an idea where we dropped.

CHAIRMAN CLARK: I don't think so. I don't recall that response.

MR. REHWINKEL: Okay. All right.

MR. HETRICK: Charles, you were going on for about three or four minutes before we could get anybody's attention --

MR. REHWINKEL: Okay.

MR. HETRICK: -- so sequence it backwards a bit. Thank you.

MR. REHWINKEL: Okay. Here's-- did you hear me ask Mr. Coffey about the on-site versus off-site work?

CHAIRMAN CLARK: Yes, the maintenance by Siemens?

MR. REHWINKEL: Yes. And there were some -- the resin work was done off-site, and it was a rewind kit brought back to the plant site, did you hear that?

CHAIRMAN CLARK: My last memory was you were on the robotics about was it a human or a robot going in the machine, that was the last part I remember.

MR. REHWINKEL: All right. If -- could the court reporter -- we can reconstruct this, because I know you have an obligation to put this out to the public, if the court reporter could read my question where I asked him -- I said I was going to talk about it later but I will do it right now, is to ask about how much of this work was done on-site.

(Whereupon, the court reporter read the

requested portion of the record.)

CHAIRMAN CLARK: I think -- I think we're there. Okay, let's pick up from that point. Everybody is kind of agreeing that we heard that part.

MR. REHWINKEL: Okay. So, Mr. Chairman, if you would like, I will just ask that question again.

CHAIRMAN CLARK: Yes, sir, please.

MR. REHWINKEL: Okay. Back on the record.

BY MR. REHWINKEL:

Q Mr. Coffey, I had seen some information that in, I think it was in the RCE and some of the other materials, that the rewind was done on-site, but can you tell me whether that was entirely true, or were there functions that were done on-site and off-site?

A Yes, there are rewind -- the rewind activities occur on-site and off-site. The type of activities that occur off-site have to do with the construction of the coils and the laminations, and insulating of those materials to construct them into a rebuild kit. That rebuild kit is then subsequently sent to the site.

And the activities that occur on-site is the demolition of the old generator that was damaged in a manner that you could still do forensics while you were disassembling it, and then the reconstruction of it using the rebuild kit that was sent to the site.

And so if the -- if, for example, the one of the three causes was a particle that was introduced during manufacturing, that could have happened off-site when those coils were getting insulated, and then went when it was sent to the site it was built right into the machine. If not, when the machine was getting constructed out, then it would be one of those other two causes where it was constructed on-site in 2012.

Q We may have confused timelines. I am talking about in 2012 --

A Yes.

Q -- you talked about damage. The 2012 rewind was just to facilitate an uprate in the unit as well as the generator's capacity from 1,000 megawatts to 1,200 megawatts, is that right?

A Yes. That's true. But you would still order a rewind kit from the person that's doing it, and they would construct that rewind kit off-site, and then they would have that delivered to the site prior to the planned outage in 2012, and the same sequence would occur. The only difference between 2012 and 2019 is, is that it was done planned versus unplanned.

Q Okay.

MR. REHWINKEL: Mr. Chairman, would you beg -- can I beg your indulgence? Somebody is hammering outside my office, and I need to try to put a stop to it?

CHAIRMAN CLARK: Yes, sir. Please do.

MR. REHWINKEL: Can I take a brief pause?

(Discussion off the record.)

BY MR. REHWINKEL:

Q Well, thank you for -- for that clarification. We will come back to it in a little bit.

But just to go back to the event that occurred in April 25th that tripped the unit, you were running what was an hour-long reactive power test at PSL 1, is that right?

A That's correct. Yes.

Q Okay. And would it be correct to say that while the test was run, that the -- that while the test was being run at 100 percent real power and 55 percent reactive power, or 50 percent reactive power, you still ran the unit during that test within the D curves, or the generator capability curves, is that right?

A Yes. It was well within the generator capability curves. And we actually had a challenge to validate prior to doing any of that required testing that we would remain within them the entire time, and we did.

Q Okay. So I don't want you to speculate, and if you can't answer this question, I understand.

No one has suggested that the reactive power test in any way caused the damage. It just was run at a high level that may have brought a magnetic termite, if that's what caused it, all the way through the insulation the last little bit, is that fair?

A I -- I don't -- I don't believe that to be correct, Mr. Rehwinkel. What I would -- what I would -- what I would say is, and it states it in the root cause, that there was a secondary forcing function, likely, in this case, vibration of the machine. And so if it were a contaminant or a particle, that that inherent vibration that exists with rotating machinery worked itself through to the point of failure at that time.

I am not sure that doing the reactive load testing would have contributed to that or not, but we were at that -- it was a prerogative failure, meaning it was occurring over many years, and then it just got to the point of failing underneath -- underneath the materials that hadn't failed.

Q Okay. And I just want to eliminate that. That's not really -- the reactive power test is not the cause in any way, no one identified it that way, right?

A   No, it was not the cause. It was refuted
as -- it was refuted as even contributing.
Q   Okay. Can you -- we talked a little bit about the -- I think in your testimony, on page three, lines six through nine, you discuss an extent of condition review at Unit 2, and you did that as a result of the 2019 outage to see that the same conditions didn't exist there since both units were uprated at the same time; is that right?
A   Yes. We did an extended condition on Unit 2. Not only did we do the extended condition review on Unit 2, we also had to do an extended condition on Unit 1. We could not be -- when we found out that one of those three causes, we also had to refute that we didn't have that in any other locations as we disassembled the machines. We didn't identify anything else on Unit 1. And we also took the testing that we did on Unit 2 and reviewed all the documents and testing that we had done on Unit 2 to make sure we didn't have a concern there either, so --
Q   Okay.
A   -- that's what we did.
Q   Since -- well, when was the last time a reactive power test was run with PSL 2?
A   I don't know -- I don't know the answer to

that question. I did not look at that up, Mr. Rehwinkel. But we run those tests in accordance with -- they are FERC mandated tests that we have to run for grid reliability. And so we -- we were within the interval of the FERC mandated test, but I don't recall the last time we had done that. They are done every couple of years.

Q Okay. And each unit has to do it, or do you get to select the unit?

A Yeah, each unit has to do it, and none of our sites are exempt from it.

Q Okay. Thank you.

So going back to the narrative. During the test, about 43 minutes into it, the -- a ground fault occurred and it tripped the unit, right?

A That's right. Yes.

Q And soon thereafter, you discovered the cause of the fault and -- and very shortly thereafter ordered a repair that required a complete rewinding of the generator; is that fair?

A Yeah. Yeah, shortly is a relative term. It took us nearly a week to find the cause, but yes.

Q Okay. Okay. And the -- the repair, I think, as you alluded to in your testimony, was -- was completed -- or the rewind, if you will, was completed

in a record time for Siemens for that type of unit of 49 days, is that right?

A That's right. The entirety of the outage was 57 days. And when we went and benchmarked all utilities that had done an unplanned generator rewind, the fastest one that we found on record was 90 days, and they ranged from 90 days all the way up to 190 days, and so our benchmarking led us to believe that we were almost twice as efficient as the next quickest unplanned rewind.

(Transcript continues in sequence in Volume 3.)

CERTIFICATE OF REPORTER

STATE OF FLORIDA)
COUNTY OF LEON)

I, DEBRA KRICK, Court Reporter, do hereby certify that the foregoing proceeding was heard at the time and place herein stated.

IT IS FURTHER CERTIFIED that I stenographically reported the said proceedings; that the same has been transcribed under my direct supervision; and that this transcript constitutes a true transcription of my notes of said proceedings.

I FURTHER CERTIFY that I am not a relative, employee, attorney or counsel of any of the parties, nor am I a relative or employee of any of the parties' attorney or counsel connected with the action, nor am I financially interested in the action.

DATED this 5th day of November, 2020.

DEBRA R. KRICK
NOTARY PUBLIC
COMMISSION #HH31926
EXPIRES AUGUST 13, 2024

BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

In the Matter of:

DOCKET NO. 20200001-EI

FUEL AND PURCHASED POWER
COST RECOVERY CLAUSE WITH
GENERATING PERFORMANCE
INCENTIVE FACTOR.
_____________________________/

VOLUME 3
PAGES 453 through 547

PROCEEDINGS: HEARING

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

DATE: Tuesday, November 3, 2020

TIME: Commenced: 10:20 a.m.
Concluded: 5:12 p.m.

PLACE: Betty Easley Conference Center
Room 148
4075 Esplanade Way
Tallahassee, Florida

REPORTED BY: ANDREA KOMARIDIS WRAY
Court Reporter

APPEARANCES: (As heretofore noted.)

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

I N D E X

WITNESSES

NAME: PAGE NO.

ROBERT COFFEY

Continued Examination by Mr. Rehwinkel 456
Further Examination by Ms. Moncada 522

EXHIBITS

NUMBER:	ID	ADMITTED
54 – FPL RCE – Public Version OPC Exhibit 8	460	528
55 – Staff Interrogatory 41 Response OPC Exhibit 2	462	528
56 – St Lucie 1 Generator Ground Fault Analysis OPC Exhbit 3	483	528
57 - Siemens Stator Ground Fault Report OPC Exhibit 4C	498	
58 - Ground Fault Root Cause Statement OPC Exhibit 6C	499	

P R O C E E D I N G S

(Transcript follows in sequence from Volume 2.)

CONTINUED EXAMINATION

BY MR. REHWINKEL:

Q Now, the fact that -- that you engaged Siemens to do the rewind while you were doing a root-cause-analysis process didn't mean that -- that you didn't find them to be at fault or responsible in any way; you just had to get the OEM to do it, if it was going to be done within the shortest possible time; is that right?

A Ye- -- yes, but whenever we award a scope of work, we do a decision-making review to determine who we believe the best vendor that we would select is to go do. And we do that every time. And that review concluded that Siemens would be our best success path.

So, it -- it wasn't just Siemens gets it because they do our generators. It still went through our review process to make sure that we were selecting who we would get the most assurance with.

Q Okay. But the fact that you chose Siemens didn't mean that -- that you didn't believe or you had already determined within that week or two that they had done nothing wrong in the 2012 rewind; is that fair?

A Yes, I believe it would be fair to say that we do quite a bit of work with lots of vendor partners. Siemens is one of them. And we routinely critique and oversee their FME practice, foreign material exclusion practices, to make sure they're consistent with ours.

And we believe that their program, as well as ours, meets the industry standard and the best benchmark of -- of any of the -- the vendor partners. So, we had confidence that they could do it correctly.

Q Okay. But just since you brought that up, you didn't do an FME-practices review within the time that -- between April 25th and whenever you awarded them the scope of work to do the rewind, right?

A That's -- that's not correct. We -- we do -- that's part of the -- those items are part of any contract that we award to our vendor partners, and they're done every time, including witness points and oversight activities associated with them as well.

And our FME program is undergoing constant -- foreign material exclusion program -- it's undergoing constant assessment activities to make sure that it meets -- it meets the market.

And, as a matter of fact, I talked about our condition report program earlier that writes up any issues if there were a deficiency with such and then we would take learnings from that and bolster it. That's a

daily activity as well.
So, I would say our program and process is continuously assessed. And when we award contracts, it's -- it's put through its paces as well.
Q Okay. And I probably didn't ask the question right. You didn't make an assessment of whether, in 2012, Siemens had followed all of its FME practices before you aw- -- correctly before you awarded the scope of work for the -- the unplanned outage-related rewind, right?
A No, I would say we did do that, Mr. Rehwinkel, via the interviews that we conducted with people that were involved with it at the time and via the work documents that document all those inspections and reviews and assessments as well.
So -- so, I would say absolutely we -- if I'm understanding your question correctly -- maybe I'm not understanding your question correctly, but -- go ahead.
Q Yeah, my question is: In that window, between April 25th and a week or two after, when you awarded the rewind work to Siemens, you didn't do a specific assessment of what they did in 2012.
A Oh, no.
Q And that --
A No. No. No. We -- we did -- as -- and it's

one of the -- it's one of the attachments -- or it's one of the exhibits in here, but what we did do, speaking of that, is we had an interim causal review that was done.

And the interim causal review -- the purpose of that is to make sure, before you start up the generator, that you don't have any issues that you should have thought of before you started up, but knowing that you're not going to be done with the root cause yet because there's forensics that has to occur back at the factory.

And so, we did as much review as we can without all the information that we had to be able to start the unit back up, but then we went further on into the root cause.

So, the answer to your question is we did a partial assessment including that, but didn't take it all the way to the point of understanding the cause because forensics wasn't done yet.

MR. REHWINKEL: Okay. Let's go ahead and identify Exhibit 8, OPC Exhibit 8. I think this will be No. 54.

CHAIRMAN CLARK: Correct, Ms. Brownless, No. 54?

We're marking No. 54.

(Whereupon, Exhibit No. 54 was marked for identification.)

BY MR. REHWINKEL:

Q And, Mr. Coffey, if I could get you to turn to Page 42 -- Bates 42.

A Okay. I'm there.

Q And this is a list of sources-cited documents, in Section 11.

A Oh, I'm on the wrong Page 42. Okay. Yes, now I'm on the right 42.

Q Yeah, you see it?

A Yes.

Q Is that what you were trying to direct me to? Is it --

A No, I was --

Q When you said --

A Pardon me?

Q You were -- you were talking about there was -- there was something related to Siemens and FME that was part of a document.

A Oh, no, I was talking about their original contract, but we have a -- if you were to go to Attachment -- or Exhibit 9, Exhibit 9 is an interim root-cause evaluation dated -- the event date is dated April 25th, but there's two signatures on it, May 31st of '19.

This was an interim -- interim causal review that was done prior to starting up the machine, but before the final root cause was done, which assessed elements of the program that were in question.

Q Okay. I apologize. Somewhere in here, you said there is a -- a discussion of the FME activities of Siemens?

A Well, it's not in the discussion of the FME activities of Siemens; it is a review of what the potential causes are for the generator rewind -- for the generator issue, and FME is one of those potential causes.

So, we were assessing an FME cause as part of this even while we were doing the generator rewind, itself. And I was answering that in context of your question, were we doing any assessment of the FME during the April 25th time period when we were doing this. And we were, but we weren't done with it yet.

Q Okay. All right. But that -- that interim assessment, if you will, was before you restarted the generator, not before you awarded the -- the work to Siemens to do the rewind; is that correct?

A That's true. That's true, yes.

MR. REHWINKEL: Okay. All right. Let's go, if we can, to Exhibit 2, OPC Exhibit 2. And I

guess this will be No. 55.
CHAIRMAN CLARK: That's marked No. 55.
(Whereupon, Exhibit No. 55 was marked for identification.)
BY MR. REHWINKEL:
Q This is Staff Interrogatory 41 response.
A Yes, sir, I'm there.
Q And -- okay. Is it fair to say that this -- this response, No. G, which refers you over to Attachment 1, shows the replacement power costs associated with the outage of 18,361,621?
MS. MONCADA: I'm going to object, Mr. Rehwinkel. That subpart of the interrogatory was not sponsored by Mr. Coffey.
MR. REHWINKEL: Okay. Are you asking that he not be allowed to answer that question?
MS. MONCADA: I'm saying that that's a subject matter outside of his testimony.
MR. REHWINKEL: Well, Mr. Chairman, I'm trying to --
MS. MONCADA: If you want, I can stipulate -- I can stipulate --
MR. REHWINKEL: Okay. I'm just trying to establish -- all I want to ask in this is, is the replacement power costs, the repair costs, and --

and the inspection repair costs recovery method.
Mr. Coffey testified about insurance proceeds and repair cost recovery in his testimony that he filed. So, I --
MS. MONCADA: That's -- that's fair. We stand by the numbers that are in this exhibit, if you want to just have him read it. I -- I don't think that he is the appropriate person to talk about dollars; he's an operational witness.
So, what we have here is the yin to yang, Mr. Menendez.
MR. REHWINKEL: I understand.
Let -- let me do this and I'll ask these -- I'll ask a question one way and see if Ms. Moncada has any objection to it.
And my question would be -- and this -- would be this: Is it true that the replacement power costs associated with the outage was 18,361,621; and was the repair cost attributable to the outage approximately $29 million.
And -- and I would ask if -- if we can either get a stipulation that that was the case or if he can answer it just based on review of this document.
MS. MONCADA: I will stipulate to those

numbers, but I will pose a further objection that, yes, we did provide the amount of the repair costs in the response to the interrogatory when staff requested it, but that is outside the scope of what's being -- or what would be recovered through the Fuel Clause; it is a base cost.

MR. REHWINKEL: I understand, except that -- yeah. I -- I would -- I appreciate that stipulation and I -- I also acknowledge that repair costs are not the subject of this hearing.

BY MR. REHWINKEL:

Q On Page 5 of your -- of your July 27th testimony, Mr. Coffey --

A Yep, I'm there.

Q -- you -- on Line 21, you state that the company filed a re- -- an insurance claim for reimbursement of costs incurred as a result of the event and that it does not include replacement fuel costs; is that right?

A That's -- that's right. Replacement fuel costs had a 12-week limiting factor associated with it. So, we did file for a NEIL insurance claim.

Q Okay. NEIL is N-E-I-L, Nuclear Electric Insurance Limited?

A That's right, yes.

Q Okay. And -- all right. So, it says here that FPL submitted a claim for approximately $25.9 million for expenses associated with the event. That's on Lines 4 and 5; is that right?

A That's right. Less the -- subject to being less the $10-million deductible, that's correct.

Q Okay. And then there is a 10-percent quota share. Was that sort of like a premium in the -- in the NEIL industry?

A I -- I don't know if that's a -- I know that that's something that we have, but I don't know that it's something that's in the industry.

Q Okay. All right. So, can you tell me -- it says here in Lines 8 through 10 that you were expecting a final coverage decision in the third quarter of this year, which would have ended, I think, on September 30th.

A Yeah, we don't have --

Q -- that --

A Yes, we don't have the final report back from NEIL yet, but our conversations with them yesterday did not look like that would be favorable and that we would be granted that insurance claim, but we're still -- we don't have the final report yet.

Q Okay. All right. I'm going to ask you this

question -- you may not know the answer and I would understand if you don't: Do you know whether this $25.9 million that you state is expenses -- is that really expenses or is any of it capital?

A You know, I don't -- I don't know the answer to that. I would have to -- I would have to look that up to get the answer to that question because it's my belief that some of it might be capital, but I don't know that for sure.

Q Okay. That's fair.

Since -- do you know whether the -- there were any costs in addition to the 25.9 that's in your testimony and the 18.361 that -- replacement power costs that were incurred by the company as a result of the outage?

A I'm not aware of any additional costs.

Q Is it your testimony that the customers of FPL are solely responsible for the retail portion of all the replacement power costs per incurred -- associated with this -- the 2019 St. -- PSL 1 outage?

A I'm not -- I'm not sure I understand your question, Mr. Rehwinkel.

Q I guess --

MS. MONCADA: And I'm going to object, as this is outside his subject matter expertise.

MR. REHWINKEL: Okay. I will -- I will accept that.

BY MR. REHWINKEL:

Q Is it fair to say that FPL did not hold Siemens responsible financially for their contribution to the cause of the outage?

A I would not say that that is a fair statement. The contract delineated the warranty terms for the generator rewind and we were outside of those terms, but -- but that does not mean that the senior personnel in our organization are not in contact with senior personnel in their organization, exhibiting our displeasure or dissatisfaction with where we were on how we ensure we're going to get success going forward as we work with them.

So -- but we were outside the warranty period. So, we followed the contract, Mr. Rehwinkel.

Q Okay. So, just -- just to be clear on this point, the work occurred in January, February of 2012, related to the uprate; is that right?

A Yes.

Q The work being the -- the generator rewind associated with the increased output of the generator, right?

A Yes.

Q And it's that work that the warranty expired on under your contract terms; is that right?

A There were -- there were -- I did read the contract, myself, and in that contract, there were several different warranties that were involved with it, the longest of which was 24 months. So, any warranty claim in that contract would have expired after 24 months of operation, worst case.

So, I didn't -- I didn't compare which were a year, which was 18 months, and which was 24 months, but 24 months was the longest of the warranty periods.

Q That's fair.

It would be -- based on your experience in the industry, it would be highly unusual for there to be a seven-year warranty on -- on a maintenance or repair work; is that right?

A Based on my experience with the contracts I've -- I've reviewed, yes, but that does not mean that does not exist.

Q So, would it be fair to say that you did not pursue compensation from Siemens because of the warranty condition, not because FPL believed that Siemens was not responsible for introducing the mechanism that caused the fault that tripped the unit that caused the outage; is that fair?

A Yes, I would say that's correct.

Q Would you agree with me that the customers of FPL also pay for the original work that was done in 2012 that was part of the uprate, that, once it was completed, went into -- went into base rates?

A I would be making an assumption if I gave you the answer to that question, but I don't know it to be other than that.

Q Okay. That's a fair answer.

I just have to ask this question, but did FPL, in any way, seek compensation from Siemens, either at the -- the PSL 1 or PSL 2 sites or was there work at any other units within the NextEra family?

A I'm not -- let me make sure I understand the question. Are you talking about -- obviously you're not talking about the generator rewind in 2019, but are you talking about with Siemens, as a whole, at any time?

Q Yes, sir.

A Yes, every --

Q Related to that.

A Not related to the -- not related to the 2012 rewind, but every single time we do work with Siemens, there's a process that we go through on the things that we think met or did not meet expectations, and there's financial restitution that's reviewed on a score card to determine whether or not -- how we award funds or not. So, there's always an assessment for that that I -- that goes on.

In this particular case, for the rewind, we pulled the contract immediately, as you can probably imagine, to review what the contract terms were. And it was, like I said, two years. So, we did not go, financially, after anything associated with 2012 with Siemens.

Q All right. So, let me just make sure I ask this question the right way, just to close the loop on this. Point Beach is an affiliated -- well, it -- let me just ask you to open up Exhibit 3.

A Okay. It's open.

Q Okay. So, this is a document that was about the generator ground fault, and it was performed by your EOSS organization; is that right?

A That's right.

Q And on Page 3, there at the bottom, it says, "Operational risks: No change is recommended to operational or maintenance plans for the remaining Siemens rewound units, PSL 2, PBN 1, PBN 2, PTN 3, PTN 4. Details below. Maintaining spare winding is not economical." Did I read that right?

A You did.

Q You -- okay.
So, my question to you is -- is, as a result of what you saw as the error by Siemens at PSL 1 in 2012, did you ask them to make up for it or compensate you at any of these other units where they might have done work?
A We went back -- we went back and reviewed their program associated with foreign-material exclusion, ex- -- with testing protocols, witnessing proto- -- witness and sign-off and validation protocols for inspections, and we did not find discrepancies with any of those practices, but what we did do is make sure that we bolstered -- I shouldn't say bolstered, but we -- we did make sure that those activities were conducted with rigor for these upcoming outages, given the information that we learned from 2012.
And we did go back and review documents to see if we saw anything that was discrepant for St. Lucie Unit 2, as well as the other sites, but that was only part of their outage planning to make sure that we wouldn't have issues and we didn't find any discrepancies.
And so, we basically just bolstered our oversight of the program to make sure there were no weaknesses because we didn't find any with our document

reviews or interviews of personnel that were a part of those activities in the first place.

Q Okay. And I appreciate that operational response.

I would ask it another way, which is: Did you ask them for any discounts or compensation on future work to compensate you or the harm that they caused as -- as a result of the outage that occurred at -- at PSL 1?

A Yeah, I'm -- I'm not aware that we asked them for any discounts for this work based on the generator rewind; however, every contract negot- -- contract negotiation with us, whoever the vendor is, is -- is a pretty rigorous process where we're going after best achievable prices from all of our vendors. And so, it's -- it's -- it's something that's built into our DNA to start with.

Q Okay.

A So, not in response -- so, the answer is not in response to the work that was done in 2012; it's just our normal course of business to do that regardless.

Q All right. And just to be clear, when -- in your testimony, so I can -- I can understand the record here on Page 3 at Line 10, you --

A Okay.

Q You -- this is in your July 27th testimony. You used the word "investigation".
A You -- you said -- did you say Page 10?
Q Page 3, Line 10. I'm sorry.
A Page 3, Line 10. Okay. I'm there.
Q The investigation here is generally referring to the RCE --
A Right.
Q -- and that process; is that right?
A That's correct. One of those three causes, yes.
Q Okay. Let's look at what I think we're calling Exhibit 54, which is the RCE.
A On the Exhibit -- Exhibit --
Q -- 8.
A -- 8? Yes.
Q Yes. All right. Now, I want to go to Page 2, under the executive summary.
A Okay. I'm there.
Q And under the heading "causes," the summary conclusion of the RCE report is stated in those two sentences; is that right?
A I don't -- I'm not sure exactly what you asked, Mr. Rehwinkel.
Q Okay. It -- well, it says "causes" -- can you

read those -- those two sentences, for the record?

A Oh, yes, sir: A small puncture developed through the ground wall insulation of stator bar "Bravo" 17 and Phase "Charlie" Stator Winding resulting in a fault current path to ground. The root cause of the puncture is indeterminate.

Q And for the court reporter, you used military terminology for the letter "B" and "C," right?

A I did, yes.

Q Okay. So, I'm just trying to understand about the phrase "puncture." The -- the "puncture" terminology sounds, to me, like something comes from the outside and it goes inside; is --

A So -- so, what it's basically trying to say, Mr. Rehwinkel, is that either a contaminant of some sort in one of the two causes has worked itself out of the insulation and gave out, causing a fault path; or impact had occurred on the inner part- -- portions of the machine and worked itself in.

So, either one of those could have happened, whether it was a contaminant or magnetic termite or impact that had worked itself inward from impact. So, it's -- it's trying to capture that either it worked itself from inside out or outside in to create the path to ground.

Q Okay. So -- all right. It's not --

A And it took seven years -- it took seven years to do that.

Q Right. This isn't inconsistent with your testimony about, where you say on Page 2 -- starting on Line 19, it says: Based on the location of the insulation, FPL believes the mechanism that produced the fault was introduced in the stator during a generator rewind performed by Siemens Energy, Inc., (Siemens), in 2012 and degraded insulation gradually over the course of seven years in service.

A Right. So, if I were to -- if I were to liken this, Mr. Rehwinkel, to an extension cord, for example, inside of an extension cord, there is a couple of layers inside there. And that -- maybe a -- a red one, a white one, and a green one -- or a black one, a white one, and a green one. The outer sheath of the extension cord is completely intact, but inside that extension cord, the white wire, itself, insulation is damaged underneath.

And so, this is similar with the generator. The outer portions of the generator insulation were intact, but underneath, where the coils were -- that insulation was suspect and had an issue.

Q Does the RCE and your explanation there -- does that conclude that there could not have been a

particle in the -- inside the generator that moved inside the stator insulation to the bar?

A It does conclude that because the outer -- the outer material and epoxy was all intact with no -- that's why it took us a week to find it. We couldn't -- we couldn't find a cause because the exterior was all pristine.

Q Okay. And that goes back to one of my earlier questions to you about the logic is that it had to be Siemens.

A That's right.

Q Because they controlled the -- the stator bar and all the insulation and how it was produced.

A That -- yes, that's true. I don't -- I don't know how they get their resin, and so, they -- they may say, well, the -- the vendor that supplies the resin to us came with a contaminant and -- we didn't -- we didn't go into that level of detail, but Siemens was in charge of making sure the quality of that work was done correctly. And, clearly, we didn't get the results that we expected, so Siemens had some culpability for that.

Q Okay. Would this RCE be something you would provide to the NRC, Exhibit 8, Exhibit 54?

A It is, yes.

Q Is it required?

A It -- it is -- it is not -- it's not required, no.

Q Is that because the --

A If they -- if they -- if they requested it during an inspection, we would provide it to them, though.

Q Do you know whether it was provided to the NRC?

A I -- I'm not aware that it was requested nor was it required.

Q Okay. And it wouldn't be required because it's not an NSS component, the -- the main generator?

A Right. It's -- so, the trip, in and of itself, would hit the -- would be -- be an NRC-PI indicator, but unless they determine there was a performance deficiency at the site, they wouldn't request the product. And I'm not aware that there -- a performance deficiency was even a -- raised, based on this.

Q Okay. I said NSS, but I mean --

MS. MONCADA: Can I interrupt, for the record? Thank you.

I was just going to ask that. Can we define NSS and PI for PI indicator?

Q I -- I only said two Ss, but there's three,

right, NSSS?

A That's right.

Q Can you give the court reporter -- can you -- can you says what those stand for?

A Well, that -- N-triple -- go ahead -- NSSS systems are just -- are just a way of saying (unintelligible), so...

Q And "PI" is what?

A Performance indicator.

MS. MONCADA: Thank you.

Q Look on Page 4 -- actually, Bates 6 -- I take that back. Bates 7, 8, and 9, there are photographs.

A This is on the Exhibit 8?

Q Yes, sir.

A Okay. Let me switch back over. All right. I am there.

Q Okay. Now, these are pictures from January of 2012 of the work that Siemens was doing in the rewind project -- project; is that right?

A That's right.

Q These are two segments of the -- of the main generator, right?

A That's correct.

Q All right. And the -- the tube in the middle is where the rotor goes. Everything else around that

is -- are the st- -- the stator components; is that right?

A That's right, yes.

Q Okay. And if we look in the background there, you see what looks like tent rigging -- this -- this shows that this -- this work is going on at the PSL 1 site; is that right?

A That's -- that's right. This is the actual work, yes.

Q Okay. So, somewhere around those blue bars is that -- that's one of the 17 stator bars; is -- is that right?

A If you -- if -- if you look inside there, you see those on Page -- well, on any of the pages, actually, but you'll see there it shows the 42 slots in the core on Page 6, and then it shows the 42 coils in the stator. And then each one of those had 14 coils for each phase -- 14 times three, 42. So -- so, it's showing you that picture of them on slot -- Page 6 there.

Q Okay. So, this is the environment where the -- that Siemens had control of, in your view, as far as the activities that occurred in the 2012 rewind; is that right?

A Yes, that would -- that would be correct.

Q And that means the on-site environment. I'm not talking about at the manufacturing sites, but at PSL 1, Siemens still controls this site under their contract, right?

A They would. This -- this entire area that you can't see via these pictures -- this entire area is tented in. You can't access this area without going through a watch station there that logs -- when you see materials in these pictures, they're all logged in. They're in an accountability log to make sure that they come out.

So, yes, this would all be within the purview of Siemens as work that's ongoing. And we have obvious access to it.

Q Okay. Now, who is responsible for FME exclu- -- or FME procedures inside that tent during this rewind operation?

A They -- they are responsible for that, but that does not free us from having oversight of it --

Q "They" meaning --

A -- and inspection --

Q -- Siemens?

A Siemens has control of it and it's their FME program; however, Florida Power & Light makes sure that they qualify to our standards, even using our training, and we still oversee these activities when they're -- when they're ongoing.

Q Okay.

A So, we make sure they are compliant with our program and their program is compliant with ours.

Q All right. Now, once they start the process inside that tent of -- of assembling the kit components to complete the rewind, does FPL monitor or oversee their FME procedures?

A Yes.

Q "Their" meaning Siemens.

A Yes, we do.

Q So, who has responsibility for keeping that site clean, pristine -- whatever your terminology is -- in accordance with the -- the appropriate FME procedures?

A Siemens -- Siemens has that, but FPL still has governance and oversight to make sure that they are complying.

Q So, you -- it's not -- wouldn't be your testimony that FPL has no responsibility to ensure that the vendor takes appropriate steps to ensure that FME procedures are followed at this -- at their rewind work site on -- on the PSL 1 location.

A We absolutely have ownership of making sure they're on our property, operating and performing as we would expect.

Q Okay. So, it would -- I -- it would not be correct for me to assume that you had contracted away the responsibility for FME at that site -- FME-procedure adherence at that site?

A 100-percent absolutely not, did not contract that out.

Q Okay. So, in your July testimony at Page 4, Line 18 through 21 --

A I'm there.

Q -- when it says, "Additionally, contract requirements with Siemens for quality assurance were imposed in accordance with industry standards. These included expectations for inspection, testing, packaging, shipping, nonconformance process, customer communication and facilities access for mutually-agreed-upon witness points" -- did I read that right?

A Yes, you did.

Q Is -- is there -- where would FME-process adherence fit into that description, if at all?

A Nonconformance process. So, that -- that contract with Siemens was nearly 400 pages in length and it delineated -- it delineated everything in great detail: the tests to be done, what the witness points were, what programs had to be followed, the qualifications of the personnel including that they had to go to FME training -- our FME training.

And so, when we say "nonconformance processes," that's intended to encompass things like the foreign material exclusion, material handing and lifting, our scaffolding program, and various other elements that would have been tedious to put all those in there. So, nonconformance process is what their (unintelligible) says.

MR. REHWINKEL: Okay. Let's go, if we can, back to Exhibit 3. And I want to now introduce this exhibit. I don't think I -- we gave it a number. I think, Mr. Chairman, it would be No. 56.

CHAIRMAN CLARK: Yes, sir, Exhibit No. 56.

(Whereupon, Exhibit No. 56 was marked for identification.)

BY MR. REHWINKEL:

Q And this is entitled "St. Lucie 1 Generator Ground Fault Analysis." Do you have that document?

A I do.

Q Are you familiar with it?

A I'm very familiar with it.

Q This was produced in your organization; is that right?

A That's not correct.

Q It's not. Where was it produced?

A So, it was produced by the EOSS organization, Engineering and Operations Support Services group. That group owns, I would say, responsibility for maintenance programs of secondary systems like generators and large pumps and motors and such.

And so, this presentation was put together by that group, who, we have a dotted relationship with them. They work for -- they don't work for nuclear, per se, but they're dotted to nuclear, works with us -- they work with all the business units, operational business units.

And they put this leadership presentation together. This wasn't a formal root cause; this was a leadership presentation that was put together exclusive of the root cause, and then it had root-cause elements added to it along the way, but it's not a -- it's not a causal document; it's a leadership presentation.

Q Okay. Yeah, I -- I guess I -- I probably didn't ask the question right when I asked if -- if your operations over- -- oversight in your -- in your description of your responsibilities included EOSS.

I guess your answer was that the dotted-line aspect includes that?

A Yeah, they -- yeah, they -- they don't report up through me in nuclear. They report to a separate business unit than nuclear, but they are on our -- they're on our daily engineering call and they are in our actu- -- in our daily plan-of-the-day meetings, our review meetings, our progress meetings.

And so, they are incorporated into our core business, is what I'd say, but they report up to our generation rather than nuclear.

Q Okay. Fair enough.

They -- would it be fair to say this is kind of a centralized engineering-support organization that supports the south region as well as the other nuclear units?

A Yes, that would be -- that would be fair to say that, yes.

Q Okay. So --

A And not just nuclear units, Mr. Rehwinkel, the -- all operational units. A generator is a generator, and so --

Q Right.

A I treat them as nuke generators. They're generators.

Q Right. They're just part of the balance of plant.

A That's right.

Q Okay. So, this document, it says -- if I look on Page 6, there's a reference to a Greg Stone, who said he agreed that magnetic termite is the most -- well, let me -- let me stop that question and say the date of this document is July 11th, 2019, right?

A That's right.

Q And the date of the RCE is August 19th --

A That's right.

Q -- 2019.

So, is it -- is there information in the -- in what's now Exhibit 56, or OPC 3, that is inaccurate or incorrect in the -- in the light of hindsight?

A Well, I wouldn't say inaccurate or incorrect. What I would say is this presentation was not informed by the forensics of the root cause until later.

And so, I know that the -- so, this is -- there's -- there's -- there was five revisions to this document. It started out as a leadership presentation, given what we knew, and it grew over time, but this did not have the final conclusions of the forensics.

It had some forensics data as we went along, but had we used this as a causal product, we would have only went after the magnetic termite, and it could have been something completely different. And we went after corrective actions for all three of those causes rather than just the one cause that was listed in here to prevent it from happening again.

So, I would just say that the document has some accurate information in it; it's just not holistic of everything that would have -- that could have occurred.

Q Okay. So, what you said isn't that you determined that it wasn't a magnetic termite that caused the problem; you just said it's one of three things that you think is most likely to have caused the problem -- the problem, right?

A Right. The magnetic termite -- that's the particle that we talk about in the root cause, and same -- same thing. Yes, that is one of the three causes. Some -- some would believe that that's -- that that's more likely than others, but all three of them cannot be refuted. None of the three can be refuted.

Q Okay. So, let me just go to Page 15 of this document.

A All right.

Q And I want to ask you about the first bullet. It says: EOSS analysis concludes the failure mode is a, quote, "magnetic termite." And then the first dash under that says, "Based on available evidence, the

failure was caused by a magnetic termite introduced by a failure of FME process." Did I read that right?

A You did.

Q Okay. So, I'm -- I'm going to ask you: Is that information inaccurate?

A I -- I am not aligned with the statement on this document; however, it's hard to argue -- the particle that we're talking about here -- they call it magnetic termites on purpose. They're not something that's easy to -- to see.

And why I said our FME programs are very strong and they're try- -- they try to be perfect, it is -- it is possible, in this particular case, that something like that could have occurred.

I will tell you, though, that the gentlemen that produced this report are aligned with the root-cause evaluation from St. Lucie, and they did a review of that after this was completed. And they are aligned with that root-cause evaluation that was conducted because this was more of a presentation than it was a formal evaluation.

Q Okay. Well, these guys -- and you said this document went through five revisions; is that correct?

A This document had mult- -- this document -- my understanding is it went through multiple revisions.

This might have been revision five.

Q Okay. That's --

A That's just like our -- just like we had an interim root cause and a final root cause and multiple drafts throughout, as we were learning information, leadership presentations were getting updated as were the causal documents, but the most effectual references we have are the root causes from both Siemens and from St. Lucie.

Q Okay. But to your knowledge, this may well be the most -- the most authoritative version of this document within the process these guys did; is that right?

A They -- at the time that they did this, they believed that the magnetic termite was the most likely cause. At the end of the root cause, they agreed that the root cause was accurate and that those three causes could not be refuted.

Q Okay. After -- at the bottom of this, the EOSS recommends that there's no change needed to current NEE -- that's NextEra Energy -- operation or maintenance plans, right?

A That's correct because when we -- we went and reviewed our program and process documents against industry standard and best practices, and they were consistent or exceeded those standards. So, that's why they -- they didn't recommend that there be any changes.

Q Okay. And it says, "... ensure strict adherence to FME process during generator work." That was their other recommendation.

A Right. That seems -- it's seems pretty self-evident, but yes, which is why we bolstered our inspection activities during the 2019 rewind. Our process was sound, but we needed to make sure that we were doubling down on those processes so that we don't have it occur again.

Q Okay. So, in concert with this recommendation and the dash under Bullet 1, no one determined that there was not a failure of the FME process; is that right?

A Right. There -- it's not conclusive that the FME processes failed, that's right.

Q But it wasn't conclusive that it didn't fail either, right --

A That -- that --

Q -- of the possible cause?

A That -- that's true. That is true.

MR. REHWINKEL: Okay. Mr. Chairman, it's 3:30. I'm about to change topics a little bit in -- in this line of cross. I'm happy to keep going, but I thought I would ask if anyone -- if we need a break.

CHAIRMAN CLARK: Yes, sir. We can -- I tend to agree. We'll give our court reporter just a few minutes. Let's take a ten-minute recess. Ten-minute recess.

MR. REHWINKEL: Thank you.

CHAIRMAN CLARK: Mr. Rehwinkel, let me ask you, before we do that -- I'm just going to try to make determinations for the afternoon. How long do you anticipate the remainder of your questions for this witness?

MR. REHWINKEL: I think I'm a little beyond halfway. I believe that, given some of the testimony and some of the facts that we've elicited, that we probably will be able to cut out what I had anticipated. So, I think I can conclude before 5:00.

CHAIRMAN CLARK: All right. Let me check with Ms. Putnal and Mr. Brew. What's your anticipation?

MS. PUTNAL: Thank you. This is Karen Putnal. FIPUG has no questions.

CHAIRMAN CLARK: Okay. And Mr. Brew?

MR. BREW: Mr. Chairman, I have no questions for --

CHAIRMAN CLARK: Okay.
MR. BREW: -- FPL.
CHAIRMAN CLARK: Sorry about that.
Staff, just a few? You have some questions?
Okay. No problem.
All right. Good. That's just giving me the indication that we're going to go ahead and try to wrap this up this afternoon. After that line of questions is up, we're probably looking at 45 minutes to conclude everything. So, we're going to try to wrap this hearing up this afternoon.
Let's take a quick ten-minute break, come back, and we'll trudge through the rest of it. Thank you.
(Brief recess.)
CHAIRMAN CLARK: Let's get at least two more commissioners -- or at least one and we'll go.
We've got one. Let's roll.
MR. REHWINKEL: All righty.
BY MR. REHWINKEL:
Q Okay. Mr. Coffey, if I could get you to go to Page 2, it's a sentence we've looked at before, but on Lines 18 and 19, it says, "The cause of the insulation fault was investigated, but could not be definitively confirmed." Do you see that?

A Are you on the presentation still?

Q I'm sorry. I'm on your July testimony. I think you can put the presentation aside.

A Okay. I'm on my July testimony and I'm on Page 2 now.

Q Yes. And the sentence I read is -- is the one that starts and ends on 18 and 19.

A Okay. I'm there.

Q And then if I could get you to turn to Page 20 of the RCE, Exhibit 8 -- or Exhibit 54.

MS. MONCADA: What page? 20?

MR. REHWINKEL: Page -- Bates 20, yes. It's...

THE WITNESS: Okay. I'm there.

BY MR. REHWINKEL:

Q The heading is -- it's Section B: Based on the above documentation, categorize the results using the causal factor characterization matrix below -- do you see that?

A Yes.

Q Is -- is this discussion here the basis for the phrase "could not be definitively confirmed"?

A It -- it is. All that's really -- yes, it's really trying to state that it could be one of the three things that it talked about, but we couldn't -- via the forensics that we had and the analysis that we did, we couldn't say definitively that any one of the three was the cause.

Q Okay.

A So, in our minds, we have to address corrective action for all of them.

Q All right. When I looked in this first paragraph, about two-thirds of the way down, there's a phrase -- there's a couple of sentences that start: The nature of these possible failure mechanisms is such that the causal factor lies within the manufacturer and/or assembly process for this stator.

The causal factor is outside of the scope of the station. No gaps in the station process or external oversight were identified. The root cause is indeterminate.

Did I read that right?

A You did. That's what it -- that's what it says -- states.

Q And this means that basically it was on the Siemens side of the fence and not FPL's side of the fence, where the cause was introduced into the generator.

A Yeah --

Q Is that right?

A -- it means it was -- yes, it means it was within the context of the contract that we had with Siemens for their portion of the work, but I -- I just -- I want to make sure I am clear, it does not take away our oversight and inspection activities that go on during this as we do these activities, Mr. Rehwinkel.

Q Okay. And there is a -- an asterisk under the table there. And it says: In accordance with the EI-AA-100-1005, quote, "If the lack of cause identification is beyond the scope of the plant, the team will issue a final report listing the cause as indeterminate."

Is -- does that mean that -- that, because FPL -- because you saw the causal factor on the Siemens side, that -- that FPL personnel could not make a determination of exactly what happened because it was -- it was behind the veil?

A Well, that -- that TI- -- that's in accordance with TIAA. That's -- that's one of our performance-improvement procedures that dictates how we do causal evaluations. That -- that procedure is also under Nuclear Regulatory Commission's group need for a problem identification and resolution inspection.

And normally, when you have a causal product, you would get a root cause on a single element and then that would have the effect of actually preventing recurrence.

Since we couldn't do that in this particular case, and we had to have multiple, this is the way for us to follow our -- our problem-identification/ resolution process to shore up that, while we couldn't conclude one item was it, we're going to blanket the three and take actions as necessary to try to prevent any -- prevent any one of them, if that makes sense.

Q Okay. Yes. Thank you.

All right. I told you to put away Exhibit 3, but I -- I do need to ask you a question about it again. This is --

A All right. I'm there.

Q Yes. On Bates Page 3 -- and I'm not trying to be flip here, I'm just trying to put the context of this document in the record. It says, "What is the pain?" Do you see that in the middle?

A Yep.

Q And I guess EFOR means a forced outage of about --

A Equi- --

Q -- 59 days?

A Equivalent Forced Outage Rate, yes.

Q Okay. And lost generation of 1.3757- --

75-megawatt hours, right?

A Right.

Q Now, this was for a specific audience, but the pain really is -- is suffered by the customers if they have to pay for the replacement power and the repair costs, right?

A I -- well, I guess the answer to your question is yes.

Q Shareholders don't absorb the pain if the customers pick it all up, right?

A I'm not -- I'm not sure I'd agree with that statement. There's quite a bit of a pain that's felt by all, Mr. Rehwinkel.

Q That's a fair answer.

Let me ask you to go to this Siemens RCE, which is Exhibit 4.

A All right.

MR. REHWINKEL: And it's 4C, Mr. Chairman. I think we need to give this an exhibit number, which I think is 57.

Mr. Chairman?

CHAIRMAN CLARK: I'm sorry?

MR. REHWINKEL: I was -- Exhibit 4C -- I want to give that Exhibit No. -- I think it's 57.

CHAIRMAN CLARK: Yes, that is correct. My apologies.

MR. REHWINKEL: That's okay.

(Whereupon, Exhibit No. 57 marked for identification.)

BY MR. REHWINKEL:

Q And this is a confidential document, so I'm going to ask you not to verbalize any information unless you're absolutely sure --

A Okay.

Q -- that it is not confidential. And I think my first question is -- to you is can you tell me the date of it?

A The date of this?

Q Is that confidential?

A No, the date is not confidential.

Q Okay. And that's April 20- -- August 23rd, 2019?

A Well, this -- this is -- this is when -- this is when this document here is dated, but the actual root cause, itself, for Siemens finished in July. And then they had a review and approval process for it. So, their -- their root cause finished (unintelligible) our root cause.

MR. REHWINKEL: Okay. So, if we look at Exhibit 6C -- this is a letter dated -- well, Mr. Chairman, I would like to give this an exhibit number. This is a confidential exhibit, 6C. And that would be 58.

CHAIRMAN CLARK: That will be 58.

MR. REHWINKEL: That would be 58? Okay.

(Whereupon, Exhibit No. 58 marked for identification.)

BY MR. REHWINKEL:

Q And this would be, Mr. Coffey, a letter from Siemens to FPL -- and this is confidential. So, this is just summarizing the conclusions that their RCE process reached with respect to the -- the fault; is that right?

A That's right. And this is why I said their documents were completed in July because they sent out this letter on July 24th.

Q Okay. So, just for the record, this isn't showing that they reached a conclusion based on a phone call that's mentioned in the letter and then they wrote their -- their RCE to fit that conclusion.

A No, that's not ac- -- no, that's not accurate.

Q Okay. And I wasn't trying to suggest that. I just wanted to make sure that, because they're kind of the cart -- appears to be ahead of the horse, that's not really what happened, right?

A That's right. That's exactly right.

Q And this document --

A Yeah, and I --

Q Go ahead.

A No, they -- the -- the date may be eluding me, but I thought they completed their root cause on July 19th and this letter came out on July 24th. I may be off by a day or two on the July 19th -- I can look that up if you need it -- but they were completed with their product in July.

Q Okay. So, you -- you didn't get out ahead of Siemens. They completed it -- and, in fact, this document, which is Exhibit 58, is referenced on Page 20- -- 43 of Exhibit 8 -- Exhibit 54. It has as -- in the table, it's D45 in the -- in the documentation; is that right?

A Right.

MS. MONCADA: What -- what page of Exhibit 8 was it?

MR. REHWINKEL: 43.

MS. MONCADA: Okay. Thank you.

BY MR. REHWINKEL:

Q Yes. So, Exhibit 58 is what is D48 -- D45 in the sources-cited table, right?

A I -- I don't -- I'm not sure I understand the question.

Q Okay. D45 on Page 43 -- it says, St. Lucie U1 stator ground fault root-cause statement, Siemens letter dated June 24th, 2019.

A June or July 24?

Q Oh, June 24 -- okay. I -- I totally --

A Somehow -- somehow, I'm all confused right now.

Q I apologize. I was reading -- I saw the 24th and 2019 and my mind transposed June and July. So -- all right.

So, that may be a different document?

A I'm not sure. Are -- I'm not -- I'm not sure of the answer to that.

Q Okay. That's fine.

A To the question. I know that Siemens had their root cause that was in July. They had a letter that went out on July 24th giving an exec summary of their root cause, and our root cause completed and was signed off on August 19th.

Q Okay. It's just -- if I look at on Exhibit 58, the July 24 letter, it said "subject," and it seems to say almost exactly the same thing that D45 says in that table, but it just has the date June.

A Okay. I'm not sure why -- I'm not sure why that's the case.

Q Okay. Is it probably -- is it probable that's a typo, the June, and it really is July 24th?

A It -- it's possible, but I don't know that for a fact.

Q Okay. And -- yeah, I understand.

All right. So, let's go back to the -- the Siemens RCE, which, again, is confidential.

A Okay.

Q And in the abstract section, it would probably -- if someone wanted to fly-spec this document and document Exhibit 6C, the summary in the July 24 letter in this abstract would probably be pretty close in the conclusion of the -- of the Siemens RCE; is that right?

A Yeah, I believe so.

Q Can I get you to turn to Page 8 of the RCE, the Bates Page 8, which is confidential Page 7. And there's a heading, it says "2.3 general fleet data." Do you see that?

A Yes, I see that.

Q Okay. Now, without reading this confidential information out -- aloud, can you look at it and answer me this question: Do you have any reason to believe or to disagree with this history of this type of generator?

A I -- I don't have any reason to believe that, no.

Q I -- I asked do you have any reason to disagree with -- with their characterization of their fleet experience.

A Yeah, I don't -- I don't have any reason to disagree, no.

Q Okay. All right. All right. I'm going to ask you a question that I want to make sure I don't ask -- or elicit confidential information. Do you believe that the Siemens RCE, which is Exhibit 57, reached a conclusion about Siemens' responsibility for the -- the mechanism that caused the ground fault?

A I believe that their root cause -- so, I believe that their root cause was a technical root cause, and it came up with technical causes for it and not much more than that.

Q Okay. Do you think that Siemens accepted responsibility for causing the ground fault? And I'm not asking with respect to any particular document.

A I don't have any knowledge that supports or refutes that they do. I do know that they were well-aware of the warranty period, themselves, and knew themselves to be outside of it.

They were -- so, I'm not aware of any information that -- that acknowledges that -- supported or refuted it.

Q Okay. All right. I want to turn away from the April 2019 events.

Now, in your September testimony -- I think we can put the July testimony away. As soon as I say that, I'll probably ask you a question about it, but let's try -- move to the September 3rd testimony.

A Okay.

Q Here, you discuss outages at PSL 2 and Turkey Point 3 and 4 right?

A Yes.

Q Now, isn't it true that the Turkey Point 3 outage was really a series -- as you discuss it in your testimony -- really a series of related outages that -- events that occurred over a three- to four-day period?

MS. MONCADA: I object to this line of questioning. What's at issue before the Commission today are Issues 2F and 2G. 2F has to do with the St. Lucie outage at Unit 1 in 2019; and 2G has to do with the St. Lucie outage in March of this year.

The Turkey Point outages are not at issue in this docket.

MR. REHWINKEL: Mr. Chairman, can I respond --

MS. MONCADA: I do recognize --

MR. REHWINKEL: All right. Go ahead.

MS. MONCADA: I recognize they are in his testimony, but they are not at issue now. And, Commissioners and Mr. Chairman, they are not included in the factor that we would ask the Commission to approve in this docket.

CHAIRMAN CLARK: Mr. Rehwinkel?

MR. REHWINKEL: Yes, Mr. Chairman, I am well-aware of that, but we are here to determine whether FPL was prudent in its actions with respect to the Turkey Point -- I mean, the Port St. -- Port -- the Port St. Lucie Unit 1 and the Port St. Lucie Unit 2 as described in Issue -- I forget -- is it Issue 2H?

And part of the --

MS. MONCADA: It's 2- (unintelligible).

MR. REHWINKEL: Part of the factors that the Commission needs to consider is the overall readiness and responsiveness of the FPL nuclear organization to ensure that its units are prudently operated.

We heard testimony at the beginning about -- I forget the phrase, "efficient and" -- I'll have to go back to the June 27th testimony -- "appropriate and efficient," and we heard testimony about the entire nuclear organization responding as well as the stations.

So, my testimony -- which I'm happy to proffer, if -- if we have to go that route -- is to explore the experience in this time frame, early 2019 through 2020.

CHAIRMAN CLARK: All right. Let me counsel with my Counsel for one moment. I understand Ms. Moncada's objection.

We're going to take -- we're going to take about a two-minute recess. Let me get some advice here. Just one second -- two minutes.

MR. REHWINKEL: Okay. Mr. -- before you do that, I guess I would like clarification. Is Ms. Moncada asking that you prohibit my questions?

MS. MONCADA: I am.

MR. REHWINKEL: Okay.

CHAIRMAN CLARK: All right. Stand by.

(Brief recess.)

CHAIRMAN CLARK: Mr. Rehwinkel, can you point me to the point in Mr. Coffey's testimony that addressed the Turkey Point issue?

MR. REHWINKEL: Yes. If you'll look in his September 3rd testimony, which he summarized, there is, starting on Line 12 of Page 4.

CHAIRMAN CLARK: Okay. I think that --

MR. REHWINKEL: -- through Page 6, Turkey Point Units 3 and 4 are both discussed.

CHAIRMAN CLARK: Okay. We're -- give us one second.

MR. REHWINKEL: I -- I want to ask him questions about that and confirm it.

CHAIRMAN CLARK: That's all we need right this second.

(Brief recess.)

CHAIRMAN CLARK: All right. Mr. Rehwinkel, I'm going to allow the line of questioning. I just want to try to keep it in the correct context.

Ms. Moncada, he opened the door in his direct testimony -- prefiled testimony. We're going to ease down this road. If there's something that specifically we need to come back and address, again, we'll -- we'll try it again.

The witness can answer the question.

BY MR. REHWINKEL:

Q Mr. Coffey, do you want me to repeat the question?

A Yes, please.

Q Yes. Okay. So, my question was: Is -- isn't it true that the Turkey Point 3 outage that you refer to in your testimony was really a series of related events

that occurred over a three- to four-day period?

A It -- it is true that there were three items during the seven-day period, yes.

Q Okay. And didn't the NRC initiate a special inspection at Turkey Point on August 31, before your testimony was filed, related to the -- those events rel- -- in that seven-day outage period?

A They did -- they did conduct a special inspection at the site and they exited that special inspection at the end of last week.

Q Okay. Was that special inspection initially supposed to last a week?

A The special inspections are not defined by a period of time. They're -- they're special inspections. So, they go on as long as the NRC determines they need to do them for.

Q Okay. A special inspection is not a routine inspection by the NRC, is it?

A It's not a routine -- it's not a rou- -- well, it's not a routine -- it's not on their routine inspection matrix, but if they -- if they determine they need to do an inspection for some reason, they do an inspection.

Q It is usually in response to a significant operational power-reactor event or a significant

unplanned degraded condition identified either by the licensee or the NRC; is that right?

A It -- it could be, but it may not be, and the -- the exit from those inspections is what determines whether or not it was (technical interruption) or not.

Q When you say exit, do you mean that they issued a report or they left the site?

A The -- the issue is not -- the -- the report is not issued yet. They have a certain period of time to issue the final report, but they did exit -- they did exit with us.

Q Okay. So --

A The formal -- they formal exit and then they have 45 or 60 days to submit a report.

Q It's true -- it's 45 days, isn't it?

A I -- I don't recall if it's 45 or 60, but it's one of those two.

Q Okay. And the -- this inspection was conducted by a five-person team led by the senior inspector at the Duke Harris plant; is that right?

A That's right.

Q And they included a senior reactor analyst from NRC?

A They did.

Q This inspection was announced a little over a month after the NRC issued a notice of apparent violation on July 23rd regarding the falsification of documents -- of documentation of the inspection and maintenance of a safety-related check valve at a Turkey Point unit, right?

A Yes.

Q Did the FPL challenge or does FPL intend to challenge that notice?

MS. MONCADA: Mr. Chairman, now this does go outside the corners of Mr. Coffey's testimony. And, again, we are here on Issues 2F and 2G, and none of this goes to whether FPL acted prudently with respect to the two outages that are at issue.

CHAIRMAN CLARK: Yeah, you're wandering a little bit, Mr. Rehwinkel. I kind of agree, that question is --

MR. REHWINKEL: May I be heard?

CHAIRMAN CLARK: Sure.

MR. REHWINKEL: Okay. Earlier in cross-examination, as part of the testimony on the -- this issue -- the 2019 St. Lucie 1 issue, we heard testimony about the rigor of the FME program and the documentation related to FME process, logging of information, and documentation.

And the Commission is asked to accept that FPL has a robust and -- I don't think he used the words "state-of-the-art," but a high-quality FME exclusion program, which is, per the testimony, related to documentation and is a maintenance-related function as well as an operational function.

We could undergo some more cross-examination about what the NRC expects in the FME process in terms of quality assurance, in terms of compliance with CF- -- 10CFR50 Appendix B, but I'll spare you that and say that FPL's regulatory experience with respect to documentation before the NRC is relevant to the Commission's consideration about the conditions in the nuclear segment of FPL.

MS. MONCADA: Mr. Rehwinkel is trying to open up the entirety of FPL's nuclear operations in the context of the Commission's decisions on 2F and 2G, which are related to two specific outage events at the St. Lucie plant. And that's an inappropriate opening of the scope of what's at issue in this docket.

CHAIRMAN CLARK: I -- I agree. I think we need to keep this a little more focused onto -- to the specifics related to the previous outages.

Mr. Coffey -- Ms. Moncada has testified that Mr. Coffey is not the correct person to answer those que- -- that particular question anyway. So, let's -- let's move on.

MR. REHWINKEL: Well, I would like to proffer my questions, then, Mr. Chairman, because this man -- he is the vice president of nuclear. He's where most of the buck stops with respect to the nuclear fleet.

And I think, you know, I've been very impressed with his knowledge and his candor. I think he can and should answer these questions, if the Commission is expected to, you know, stamp the prudence of the actions related to this outage.

This is -- this is a lot of money that the customers expect the company to answer for. And I don't think that -- I mean, everyone makes mistakes, but the customers are entitled to understand whether the -- the actions of FPL are -- are prudent.

And I want to proffer the questions and answer. You can -- you can isolate them in the record and we can address it in -- in post-hearing filings.

CHAIRMAN CLARK: I still think that we're getting --

MS. MONCADA: And I'm just saying there has been no rubber stamp, Mr. Chairman. That's why --

MR. REHWINKEL: I did not use the word "rubber stamp."

MS. MONCADA: Okay.

(Simultaneous speakers.)

CHAIRMAN CLARK: The objection has been sustained. Let's move on.

MS. HELTON: Mr. Chairman, Mr. Rehwinkel has asked to proffer, which means that he wants to ask the witness questions in an isolated portion of the transcript and have the witness answer them. So, it won't be part of the record, necessarily, on which you make a decision, but he's reserving his right to take issue with that on appeal.

CHAIRMAN CLARK: Okay. I guess we can do that.

MS. HELTON: Yes, sir.

MR. REHWINKEL: And before -- before I undertake that, Mr. Chairman -- and I'm not trying to bargain this -- but this -- this issue -- if I have to proffer this, this is going to take this from a bench decision to a briefing event.

And -- and I'm perfectly happy to do that.

And I know that -- that, you know, it -- it may be that FPL is happy with that, too, but I'm entitled to ask the questions, whether under a proffer or as a part of the record.

CHAIRMAN CLARK: I have no problem with you guys briefing this thing. It's -- that's irrelevant to me.

Ms. Moncada?

MS. MONCADA: This is just taking it outside the scope of what's at issue. I don't agree with the questioning and I think, if he wants to make a proffer and the Commission wants to go through that process, then we'll go through it.

MR. REHWINKEL: Okay.

CHAIRMAN CLARK: What I -- what -- Ms. Helton, any comments?

MS. HELTON: Well, Mr. Chairman, it's my recommendation that, if Mr. Rehwinkel is asking to make a proffer, that we need to let him make a proffer.

So, I think you need to make -- he would need to make it clear on the record that this is his proffer and, when his proffer ends, that part of the transcript will not be part of the record for your decision. He's preserving his right to take

issue with your evidentiary ruling on appeal.
     CHAIRMAN CLARK: All right. You may begin, Mr. Rehwinkel.
     MR. REHWINKEL: Okay. So, my first question --
     COMMISSIONER BROWN: Can I --
     CHAIRMAN CLARK: Oh, one -- one question. Commissioner Brown.
     COMMISSIONER BROWN: I'm sorry. It just has piqued my interest a little bit. I'm curious if Mr. Rehwinkel had an opportunity, prior to this hearing, to depose Mr. Coffey.
     MR. REHWINKEL: I -- I could have deposed Mr. Coffey --
     COMMISSIONER BROWN: No, I --
     MR. REHWINKEL: -- July 27th --
     COMMISSIONER BROWN: -- before this hearing.
     MR. REHWINKEL: So, yeah, I've had an opportunity. I've not done that.
     COMMISSIONER BROWN: Okay. Thank you.
     Sorry, Mr. Chairman.
     CHAIRMAN CLARK: No problem.
     MR. REHWINKEL: And I -- I have not -- I have not done that, in accordance with our burden of proof, which is not to prove the lack of prudence.

BY MR. REHWINKEL:

Q Okay. So, Mr. Coffey, my question is, to you: Did the NRC find that the Turkey -- that Turkey Point station personnel used a measurement from 2015 in lieu of an actual measurement that should have been taken at the time of the scheduled valve inspection in January of 2019?

A No, that's not corr- -- that's not correct, Mr. Rehwinkel. Turkey Point employees found that discrepancy and reported that discrepancy, when they found it, to the NRC. We subsequently -- and the Turkey Point employees and our security staff performed a formal investigation of those activities where we found those personnel had falsified those records. And we took aggressive action against those employees, who no longer work for us, to address that issue.

That the regulators took issue with it as well was -- was not something that they had found; it was something that we had found and reported to them. So, it was a part of our normal process that we investigate and look for these things.

Now, that the NRC was interested in that maintenance activity to start with is the reason that we did the review that we did, but we answered their questions, did they actually (technical interruption) it properly, and we went further to find this issue and addressed it aggressively.

So -- and that's one of our -- that's one of our contentions when you go through this process with the NRC of, we found it, we took corrective actions, here is what the corrective actions were. And that's not been adjudicated yet.

Q Okay. So, the personnel you discussed -- were they FPL employees or contractors? I --

A They were FPL employees.

Q Okay. And when you said that's not right, was it incorrect that the employees that -- that you reported to NRC had taken a 2015 measurement and used it in lieu of making an actual measurement in 2019?

A They -- they -- well, no, that's not -- that's not correct either.

When they were performing their maintenance, they recorded some measurements that were made with some measurement and test equipment that's documented. And the actual equipment they used had not been checked out from the tool room. And so, they documented that it had been, though, and we found that discrepancy that the equipment that they say that they used wasn't on there, wasn't in the room that they did the work when they did the work.

So -- so, basically, they knowingly falsified their records and (unintelligible) them to the investigation and we subsequently released them, did a root cause with that root cause being the corrective actions that addressed all employees for NextEra, not just the ones at the Turkey Point.

Q The self-reporting you did -- that is your obligation under the code; is that correct?

A Yes. I mean, there was -- there are condition reports that are written -- that are written on that. And on condition reports of -- of those types, we also talked to the regulators on-site to let them know about what's going on.

Q You talked to the what on-site?

A The regulators, the NRC regulators.

Q Okay. The resident inspector, you mean?

A Yes, the -- yes, there are two resident inspectors that are permanently at the site.

Q Okay. I guess I am -- I understand that, in the -- the investigation report, the NRC identified that there was no log -- log-out of the requisite measurement tools that would have needed to be used to make the documented measurements; is that fair?

A Right. And so, just to put it in context, some mechanics were doing work in a safety-related room during the day. The regulator went -- the NRC inspector went several times to that room to see them do that work and he never saw them there.

He asked us if the work would -- actually been done because he didn't see them there. We pulled those peoples' gate logs for that room and, as it turns out, they were there and they had conducted the work. And we told the NRC that they had conducted the work. We -- but -- and NRC was satisfied with that.

We didn't stop our investigation there, though. We said, get the camera information, get the reporter information. We continued that investigation through to dot every "I," and we found other discrepancies that led us to falsification of records, which we addressed.

Q Okay. Thank you.

So, I think -- I had a question to you that this is an extremely serious matter and I think your answer to me was the termination of their employment reflected that; is that fair?

A That's fair.

Q Okay.

CHAIRMAN CLARK: Mr. Coffey, would you adjust your mic? We're having a little bit of a problem hearing you.

THE WITNESS: Oh, okay. I -- all right. Is that better?

CHAIRMAN CLARK: Yes, sir.

BY MR. REHWINKEL:

Q Would you agree with me that the NRC stated in its actual summary that records of inspections of safety-related equipment are material to the NRC because they indicate whether the licensee is performing quality, safety-related activities in cord- -- accordance with the -- its operating procedures and NRC regulations?

A I agree with that statement, yes.

I think it's important to note, Mr. Rehwinkel, that the NRC has four levels of performance, Columns 1 through 4; Column 1 being the best of the four columns. Turkey Point and St. Lucie are and have been in Column 1 and will remain in Column 1, even subsequent to the -- to the inspection discussed previously.

So, the -- the Florida sites are in the highest level of performance with the Nuclear Regulatory Commission.

MR. REHWINKEL: Okay. Mr. Coffey, those are all the questions I have. I appreciate, again, your -- your candor and your willingness to answer my questions. And I thank you for your time.

THE WITNESS: Thank you, sir.

MS. HELTON: So, that was the end of your proffer, Mr. Rehwinkel?

MR. REHWINKEL: Yes, and it is the end of my cross-examination as well.

CHAIRMAN CLARK: All right. Thank you very much, Mr. Rehwinkel.

I don't believe FIPUG had an questions.

So, we're -- to staff, correct?

MS. BROWNLESS: Yes, sir. We have no questions.

CHAIRMAN CLARK: Ms. Brownless.

MS. BROWNLESS: Oh, I said, we have no questions.

CHAIRMAN CLARK: Oh, I'm sorry. I thought you said, we have questions.

MS. BROWNLESS: Oh, no, sir.

CHAIRMAN CLARK: My apologies. I'm -- I'm sitting here confused. Staff has no questions.

Commissioners, the floor is yours. Any Commissioner questions for Mr. Coffey?

All right. Commissioners have no --

COMMISSIONER POLMANN: Mr. --

CHAIRMAN CLARK: -- questions -- yes, Commissioner Graham -- somebody spoke.

COMMISSIONER POLMANN: No, I was going to say, Mr. Chairman, my -- Commissioner Polmann.

CHAIRMAN CLARK: Commissioner Polmann.

COMMISSIONER POLMANN: I was going to say my questions have been answered. Thank you, Mr. Chairman.

CHAIRMAN CLARK: Thank you, sir.

All right. Ms. Moncada, redirect.

MS. MONCADA: Very briefly.

FURTHER EXAMINATION

BY MS. MONCADA:

Q Just for clarity of the record, Mr. Coffey, you explained the FME program that F- -- that FPL implements. And you gave certain examples like the con- -- the controlled environment, the watches, the barricades, the separation between the rebuild and the inspections, the cleaning, the vacuum.

Were all of those in place during the 2012 rewind?

A A lot of them was in place, yes.

MS. MONCADA: That's my redirect. That concludes my redirect, Mr. Chairman.

CHAIRMAN CLARK: All right. Let's talk exhibits. Ms. Moncada?

MS. MONCADA: FPL has no exhibits. Thank you.

MS. BROWNLESS: OPC.
CHAIRMAN CLARK: Mr. Rehwinkel.
MR. REHWINKEL: Yes, Mr. Chairman, I -- I would ask if I could get agreement from Counsel -- we briefly discussed -- well, actually -- strike that.
We would like to introduce Exhibit -- Exhibits 53 through 58.
MS. MONCADA: Can I just ask, Mr. Rehwinkel, if you know whether -- if any of those are confidential -- and I believe some of them are -- whether we have confidentiality orders in place for them?
MR. REHWINKEL: It is my understanding that all of these documents were covered by -- I don't know about orders. I know that they -- that we only received them because there was a notice of intent. I don't know the status of any RCC.
MS. MONCADA: Okay. I don't know either because I didn't know which ones you were intending to introduce as opposed to identify and discuss without introducing. And I'm wondering if maybe this is a matter we can handle after the conclusion of this hearing with staff to ensure that we have the correct protections in place.

CHAIRMAN CLARK: Rather --

MR. REHWINKEL: I'll tell you, Issue -- Exhibit 53 and 57 and 58 are confidential.

MS. MONCADA: 53, 57, 58.

MR. REHWINKEL: Yeah, those -- those are Exhibits 4C, 6C, and 7C.

Mr. Chairman, I -- I am willing to -- well, I don't know if we have redacted versions of these documents. That's what I don't know.

CHAIRMAN CLARK: Let me check with Ms. Brownless, Mr. Rehwinkel.

Ms. Brownless?

MS. BROWNLESS: I think the easiest thing to do here, because we do have a -- I don't know if these materials were provided previously pursuant to notices of intent or to formal requests for confidentiality.

Looking at them, I don't think they have been the subject of formal requests for confidentiality, which would have had to have been filed by Ms. Moncada and FP&L.

So, maybe we could just agree now that they be admitted into evidence and kept confidential pending a request for confidentiality of Iss- -- of Exhibit 53, 57, and 58, should, upon our exploration, we find out that they're not already the subject of either a confidentiality order or a request.

CHAIRMAN CLARK: Ms. Moncada, can you agree to that?

MS. MONCADA: I can.

MR. REHWINKEL: Yes --

CHAIRMAN CLARK: Mr. Rehwinkel?

MR. REHWINKEL: Ordinarily, the discovery is subject to an NOI, if it only comes to the Public Counsel. And then, if we bring it into the hearing and try to introduce it and it's introduced, then that triggers the requirement to do an RCC.

MS. BROWNLESS: So, you're in agreement with that process?

CHAIRMAN CLARK: So, does that mean --

MR. REHWINKEL: Yes, I --

CHAIRMAN CLARK: -- you're in agreement?

MR. REHWINKEL: Yes. Yeah, I -- I think it's -- it's appropriate.

It's -- I was wondering, Mr. Chairman -- normally, when we're in a -- the live hearing room, Counsel will have an opportunity to confer, but -- we don't really have that opportunity on here. I was wondering if we could take a five-minute break and Ms. Moncada and I could talk.

CHAIRMAN CLARK: I have no objection. We'll take a five-minute recess, give you guys time to huddle.

(Brief recess.)

CHAIRMAN CLARK: All right. We are ready to go back on the record.

Mr. Rehwinkel.

MR. REHWINKEL: Yes, Mr. Chairman and Commissioners, Ms. Moncada and I have conferred and we think a reasonable resolution of the conclusion of this hearing and FPL's role in this docket would be that Public Counsel does not move Exhibits 53, 57, and 58 into the record, but instead only 54, 55, and 56; and that the proffer -- restrictions on that Q-and-A is removed and it becomes part of the transcript of the record.

The Public Counsel will make a brief closing statement and we will waive briefs and -- and allow the Commission to take this to a bench vote based on the record before them.

CHAIRMAN CLARK: Okay. Ms. Moncada, you're in agreement.

MS. MONCADA: I am.

CHAIRMAN CLARK: All right. We will --

Ms. Brownless.
     MS. BROWNLESS: I just want to make sure I understand what's going on because, actually you were cutting in and out a little bit, and I was a little confused.
     So, what exhibits are we going to admit into the record? Or what exhibits do you --
     MR. REHWINKEL: 54 through 56.
     MS. BROWNLESS: 54 and 56 only?
     CHAIRMAN CLARK: 54, 55, and 56.
     MS. BROWNLESS: 54, 55, and 56.
     MR. REHWINKEL: Yes.
     MS. BROWNLESS: And everybody is okay with those going into the record.
     MS. MONCADA: No objection.
     MS. BROWNLESS: Okay. And you're not going to tender 53, 57, or 58.
     MR. REHWINKEL: Correct.
     MS. BROWNLESS: And then you would like to make a brief closing argument; is that correct?
     MR. REHWINKEL: Yes, very brief, and then we will waive briefing.
     MS. BROWNLESS: You will waive briefing after your -- you're going to do a closing statement -- closing argument in lieu of a brief so that you

waive briefs.

And you got these admitted into the record.

CHAIRMAN CLARK: And the proffered testimony is also --

MS. BROWNLESS: And the proffered testimony becomes non-proffered.

MR. REHWINKEL: Correct.

MS. BROWNLESS: Okay. Thank you so much.

CHAIRMAN CLARK: Everybody clear?

We're all good. Okay.

Back to -- we've got all your exhibits in, Mr. Rehwinkel. Those are moved into the record.

(Whereupon, Exhibit Nos. 54, 55, 56 were admitted into the record.)

CHAIRMAN CLARK: And am I missing anything before we excuse the witness?

MR. REHWINKEL: Mr. Chairman?

CHAIRMAN CLARK: Mr. Rehwinkel.

MR. REHWINKEL: Mr. Chairman, I don't know if Counsel for FIPUG is on the line. They've adopted our position in here -- and I'm not trying to throw a monkey wrench in here, but I -- I think it would be helpful for the -- for the record, if they are agreeable to waiving briefing. I didn't -- we -- only Ms. Moncada and I talked. I -- I didn't ask them.

CHAIRMAN CLARK: Okay. Understood.

Ms. Putnal, are you still on the line?

MS. PUTNAL: Yes. Thank you.

CHAIRMAN CLARK: Are you willing to waive briefs?

MS. PUTNAL: So, I -- yes, FIPUG waives its closing statement and briefing as to FP&L.

CHAIRMAN CLARK: All right. All clear.

All right. Anything else before we allow the witness to be excused? Ms. Moncada, would you like to excuse your witness?

MS. MONCADA: Yes, please, we would ask that Mr. Coffey be excused.

CHAIRMAN CLARK: All right. Mr. Coffey is excused.

All right. That concludes all of our witness testimony. So, y'all are going to have to be a little patient with me as we go through and manage this last portion of the hearing.

Ms. Brownless, where is -- what's our status? Where do we stand in the proceeding?

MS. BROWNLESS: Okay. With regard to the FPUC, Gulf, and TECO, all issues for FPUC, Gulf, and TECO have been stipulated to and approved by the Commission.

With these facts in mind with regard to FPUC, Gulf, and TECO, there is no need for briefs or further Commission action to resolve the issues before us today.

FP&L Issues 2A, 2B, 2C, 2D, 2E, 2H, 6, 7, 11, 16, 17, 19, 21, 24A, 24B, and 27 through 36 have been stipulated to and approved by the Commission. No further action is required by the Commission on these issues.

FP&L Issues 2F, 2G, 8, 9, 10, 18, 20, and 22 are outstanding. We've just heard Mr. Rehwinkel and FP&L say that Mr. Rehwinkel and the other intervenors would like the opportunity to make closing arguments and are willing to waive post-hearing briefs.

So, at this time, we would listen to Mr. Rehwinkel's closing argument. And, after that, the Commission would have the ability to conduct a bench vote on these issues, if you wish to do so.

CHAIRMAN CLARK: Continue with the Duke.

MS. BROWNLESS: With regard to Duke, no Duke issues have been stipulated or approved by the Commission. Parties have the ability to brief these issues or to offer three-minute closing arguments with regard to these issues.

Should the parties choose to make closing arguments and waive post-hearing briefs, at the conclusion of closing arguments, the Commission has the ability to conduct a bench vote on these issues, should it wish to do so.

So, I guess, at this time, we need to figure out what the position of the parties is with regard to post-hearing briefs.

CHAIRMAN CLARK: All right. Well, let's go ahead and take the FPL issue up and dispose of that and then we'll come back to the -- to the Duke issue when we get -- get to that point.

So, let's begin closing arguments. We will begin with OPC. FIPUG waived. PCS is not involved. And so, we'll do OPC and then FPL.

Mr. Rehwinkel, you're recognized for your closing argument.

MR. REHWINKEL: Thank you, Mr. Chairman, Commissioners.

The Public Counsel is concerned that customers are paying for mistakes that are being made in a nuclear-generation business that includes the wholesale market and which regulated FPL and regulated FPL-affiliated nuclear units participate and in which public information demonstrates that the nuclear generation is increasingly out of the money, in a situation where we believe FPL has not met its burden of justifying that its management was prudent in incurring the costs related to the outages at -- the outage at Port -- at -- at PSL 1, or St. Lucie Unit 1, in April of 2019.

Commissioners, FPL has not demonstrated that it took appropriate measures to protect customers from poor workmanship in the rewinding of the PSL 1 main generator in 2012.

FPL has, instead, proven that the sole cause of the failure of the generator was caused by actions or inactions of its vendor. FPL has focused its testimony on efforts to inspect the unit after the work was performed and to inspect certain vendor functions, but it has not demonstrated that it protected customers from harm related to inadequate foreign-material exclusion during the performance of its work. We believe this does not meet its burden under the law.

Thank you.

CHAIRMAN CLARK: All right. Thank you, Mr. Rehwinkel.

Ms. Moncada.

MS. MONCADA: Thank you, Mr. Chairman.

Mr. Coffey has explained in his prepared testimony as well as his live testimony today that the mechanism of injury that caused the outage last spring at St. Lucie Unit 1 was introduced during the 2012 rewind.

During that rewind process, FPL had industry-best FME program and processes in place, and we required that Siemens also implement these best practices. We performed all inspections and testing consistent with industry standards and manufacturers' recommendations. The fact that a microscop- -- microscopic particle or other contaminant or damage still was introduced does not mean FPL was imprudent.

The Commission has ruled many times, and the Florida Supreme Court has affirmed, that the standard for evaluating prudence is what a reasonable utility manager would have done in light of the conditions and circumstances which were known or should have been known at the time the decision was made. This is a standard that focuses on management and decision-making; it does not look at the results and make a judgment based on hindsight.

To that end, Mr. Coffey explained in detail that FPL had rigorous processes in place. It had a highly-controlled environment. It included watches that maintained strict access and cleanliness controls. And, in fact, we got to see some of the tenting in one of the exhibits that Mr. Rehwinkel presented today.

They were scheduling things in a (unintelligible) fashion to ensure that the demolition activities were separated from construction activities. There were cleaning activities to ensure the greatest likelihood of success. There were inspection and quality-control points. And all of these were validated, as Mr. Coffey explained, to make sure they were done properly.

As for the -- I'm sorry -- Issue 2G, which involves the return-to-service delay, you didn't really hear any testimony about that live today, but one of the exhibits, Exhibit 49 that went into the record, explains that the only management decision to be evaluated was how St. Lucie estimated the time it would take to complete the outage.

The decision was made to estimate based on standard configuration and it turns out the equipment was not in that configuration, but the total amount of time for the outage would not have changed either way.

Commissioners, FPL has satisfied the standards for demonstrating prudence and no adjustments should be made with respect to the replacement power costs related to the April 2019 outage at St. Lucie Unit 1, or the March 2020 return-to-service delay at St. Lucie Unit 2.

That concludes my -- my closing statement.

CHAIRMAN CLARK: All right. Thank you, Ms. Moncada.

Okay. We are prepared, I assume, for a bench decision, pending Commissioners' objections to a bench decision. I see no objection.

Ms. Brownless, do you have staff recommendation on Items 2F, 2G, 8, 9, 10, 18, 20, and 22?

MS. BROWNLESS: The outstanding issues that have not been stipulated to, 2F and 2G -- the staff is available to make recommendations on those issues. Mr. Wooten, I think, is available to discuss those.

CHAIRMAN CLARK: Okay. Mr. Wooten, are you on the line?

MR. WOOTEN: Good afternoon. Orlando Wooten, here.

CHAIRMAN CLARK: We'll entertain your recommendation on Item 2F and 2G.

MR. WOOTEN: Good afternoon, Commiss- -- Or- good afternoon, Commissioners. Orlando Wooten.

FPL filed, as part of its petition for fuel cost recovery, for replacement fuel costs of the April 2019 forced outage of the St. Lucie Nuclear Power Plant Unit No. 1, and March 2020 return-to-service delay of the St. Lucie Nuclear Power Plant Unit No. 2.

Based on the evidence in the record, staff recommends that both the forced outage and return-to-service delay were handled prudently by the company and no adjustments are necessary for replacement power costs.

Both unplanned outages were caused by situations out of the company's control and, when the issues were identified, they were handled as quickly and safely as possible.

The total -- total combined replacement power costs for the unplanned outages is approximately $19 million.

Staff recommends approval of Issue -- Issues 2F and 2G and is available for questions.

CHAIRMAN CLARK: All right. Thank you, Mr. Wooten.

Mr. Higgins, you want -- or Ms. Brownless, you want to go --

MS. BROWNLESS: Yes.

CHAIRMAN CLARK: -- through it -- through them all at one time?

MS. BROWNLESS: Well, what I'd like is for Mr. Wooten to please read his recommendation for Issue 2F as well as his further recommendation for 2G into the record.

CHAIRMAN CLARK: Isn't that what he just did?

MS. BROWNLESS: He gave a short summary --

CHAIRMAN CLARK: Okay.

MS. BROWNLESS: -- but there are -- there is more- specific language.

MR. WOOTEN: Yes, I can provide more-specific language, if that's requested.

In regards to Issue 2F -- do you want me to state the issue as well?

MS. BROWNLESS: No, just say Issue 2F and go with your explanation here, Mr. Wooten.

MR. WOOTEN: Okay. Issue 2F -- yes, during operations, St. Lucie Unit No. 1 experienced a ground fault that caused an automatic shut-down response.

After analysis was performed, this is believed to have been caused by the introduction of a foreign material by a vendor in 2012. This foreign material degraded the insulation of the generator gradually, causing a failure that led to the shutdown in 2019. The prepared performance was a full rewind of the generator over 49 days.

Based on the evidence contained in the record, the April 2019 forced outage at St. Lucie Nuclear Power Plant Unit No. 1 was handled prudently and the associated replacement power costs are reasonable.

In regards to Issue 2G: Yes, during the 2020 outage, FPL attempted a planned replacement of an electrical switch gear required for plant operation. During this planned replacement, an interfacing -- and interfacing conflict was discovered, which increased the scope of the work of the replacement.

FPL was previous- -- previously aware of the possibility of the conflict and, as a contingency prior to the spring 2020 outage, FPL procured and received all necessary materials to correct the potential issue; however, the duration required to correct the configuration discrepancy was not accounted for in the original outage schedule and, due to limited accessibility during plant operations, a longer outage duration was necessary.

Based on the evidence contained in the record, the March 2020 forced outage at St. Lucie Nuclear Power Plant Unit No. 2 was handled prudently and the associated re- -- replacement power m- -- replacement power costs are reasonable.

MS. BROWNLESS: And at this time, if Mr. Higgins -- Higgins could give a recommendation with regard to Issues 8, 9, 10, 18, 20, and 22.

MR. HIGGINS: Yes. Yes, ma'am. Hello, Commissioners. Devlin Higgins with Commission staff.

Staff would recommend, concerning FPL, for Issues 8, 9, 10, 18, 20, and 22, to adopt the company- -- or to approve the company's position on those issues as laid out in Order No. PSC-20200415PHO-EI, or the prehearing order, as outlined.

And staff is available for any questions you may ask. Thank you.

CHAIRMAN CLARK: Okay. That's adopt company positions on all items, right --

MS. BROWNLESS: Yes.

CHAIRMAN CLARK: -- Ms. Brownless? Okay. We're good.

All right. Commissioners, do you have any questions? Any questions?

Commissioner Brown.

COMMISSIONER BROWN: I -- I just have a comment. I appreciate staff making their recommendations on these contested issues orally today. And I -- I say I believe Witness Coffey -- I think he was very credible in his testimony and his extensive explanations to decisions that were made were valid and prudent.

Additionally, I think the exhibits that are in the record as well as the other materials support this conclusion. And, with that, I would support the staff recommendation on these contested issues.

CHAIRMAN CLARK: All right. We have a motion to approve staff's recommendation. Do we have a second?

COMMISSIONER POLMANN: Second.

COMMISSIONER FAY: Second.

CHAIRMAN CLARK: A motion and a second.

Is there any discussion? On the motion, all in favor, say aye.

(Chorus of ayes.)

CHAIRMAN CLARK: Opposed?

Motion carries. The item is approved.

All right. Next, with regard to Duke, I would ask the principals if they would like to make -- if they plan to brief on the Duke issues.

Mr. Rehwinkel?

MR. REHWINKEL: The Public Counsel does -- yes, the Public Counsel intends to brief.

CHAIRMAN CLARK: All right. Public Counsel intends to brief. That pretty much sums all of that up, then.

Ms. Brownless, what's the time line of the briefing schedule?

MS. BROWNLESS: Briefs are limited to 40 pages and are due on November 10th of 2020. A post-hearing special agenda will be held on December 15th, 2020.

CHAIRMAN CLARK: All right. Staff, are there any other matters outstanding that need to be addressed at this time?

MS. BROWNLESS: No, sir, not at this time.

MR. BERNIER: Mr. -- Mr. Chairman?

CHAIRMAN CLARK: Yes. Who was that?

MR. BERNIER: I apologize. Matt Bernier for Duke Energy.

CHAIRMAN CLARK: Mr. Bernier.

MR. BERNIER: If I could, real quickly -- thank you.

I recognize that staff is not in a position to make recommendations on certain of our issues that are -- have not really been discussed here today, but for going forward and to make sure that I do not waive this objection if this is raised again next year, Duke Energy would like, for the record, to object to OPC and FIPUG and PCS Phosphate being able to brief any issue on which they did not take a substantive position in this docket.

They have identified Issues 1A and 11 and then fallout issues 10, 18, 20, and 22, but on all remaining issues, they took no position and pointed out that Duke has the burden of proof, which is still not a position.

FIPUG and PCS adopted that "no position" and I think, under the -- the rules that we go by in the prehearing, if you don't take a position prior to hearing, you're not permitted to contest those issues and brief them.

I recognize we're not in the position for a bench vote, but I want to make sure that that objection is on the record going forward.

CHAIRMAN CLARK: Your objection is duly noted.

MR. BERNIER: Thank you.

CHAIRMAN CLARK: Any other matters?

Commissioners, any --

COMMISSIONER POLMANN: Mr. -- Mr. Chairman? Mr. Chairman?

CHAIRMAN CLARK: Yes, Commissioner Polmann.

COMMISSIONER POLMANN: May or may not be appropriate, but I think that Mr. Bernier raises, I would say, a good point. I don't know if it's something that our advisor -- the legal advisor feels comfortable making any comment on, but I -- I take it as wholly significant, valid point.

It may simply be procedural. It may be a legal point. I don't want to force the issue, but I want to respect the point, Mr. Chairman.

CHAIRMAN CLARK: All right. I'm going to ask Ms. Helton or Mr. Hetrick, one, if they would address this item for us.

Ms. Brownless, would you --

MS. BROWNLESS: Yes.

CHAIRMAN CLARK: You seem prepared and ready.

MS. BROWNLESS: Yes. With regard to Mr. Bernier's point, we spent -- staff spent a significant amount of time trying to get the parties to agree to which issues could be stipulated to and which could not.

And we -- we were aware that there were issues, as Mr. Bernier correctly points out, in which eventually the Office of Public Counsel took the position that they had no position and wanted their very-descriptive language elicited in there to what "no position" meant.

We simply ran out of time to run that all to ground. The idea staff had was, since we got to this time, that the OPC would not file briefs on those issues, but would only file a brief on the issue that they actively contested, Issue 1A and 11, and 18, 20, and 22.

And I apologize for that, but we simply ran out of time.

CHAIRMAN CLARK: Okay. Is that your agreement, Mr. Rehwinkel? Is that your intention?

MR. REHWINKEL: Yes. We're -- we're only here about Bartow and -- and the cascading dollars.

CHAIRMAN CLARK: Fallout from it? Okay.

MR. REHWINKEL: There's -- there's no hidden agenda here where we're trying to kind of keep other issues in our hip pocket to bring out in the future.

I -- I have no problem with what Mr. -- Mr. Bernier said. We don't have a hidden agenda.

CHAIRMAN CLARK: Okay. Very good.

MR. REHWINKEL: And I wasn't suggesting he's saying we were. He was doing the right thing.

CHAIRMAN CLARK: Absolutely correct.

MR. BERNIER: Thank you.

CHAIRMAN CLARK: Understood. All right. We're all good.

Any other questions? Commissioners? Anything else?

All right. If there is nothing else, I believe that concludes all of our matters for today. Thank you all very much for your participation and your indulgences today. We were able to get through all the clause dockets in a one-day hearing, and I think that's pretty amazing.

So, special thank you to all of the parties involved for your hard work and to the staff that worked on -- numerous hours on getting us to this point and to an absolutely wonderful prehearing officer who did a fantastic job. So, thank you all. Have a great day.

We stand adjourned.

(Whereupon, the proceedings concluded at 5:12 p.m.)

CERTIFICATE OF REPORTER

STATE OF FLORIDA)
COUNTY OF LEON)

I, ANDREA KOMARIDIS WRAY, Court Reporter, do hereby certify that the foregoing proceeding was heard at the time and place herein stated.

IT IS FURTHER CERTIFIED that I stenographically reported the said proceedings; that the same has been transcribed under my direct supervision; and that this transcript constitutes a true transcription of my notes of said proceedings.

I FURTHER CERTIFY that I am not a relative, employee, attorney or counsel of any of the parties, nor am I a relative or employee of any of the parties' attorney or counsel connected with the action, nor am I financially interested in the action.

DATED THIS 5th day of November, 2020.

ANDREA KOMARIDIS WRAY
NOTARY PUBLIC
COMMISSION #GG365545
EXPIRES February 9, 2021

Docket No. 20200001-EI Comprehensive Exhibit List for Entry into Hearing Record November 3, 2020					
EXH #	**Witness**	**I.D. # As Filed**	**Exhibit Description**	**Issue Nos.**	**Entered**
STAFF					
1		Exhibit List	Comprehensive Exhibit List		
DUKE ENERGY FLORIDA – DIRECT					
2	Christopher Menendez	CAM-1T	Fuel Cost Recovery True-Up (Jan – Dec. 2019).	6-11, 18-23(A-D), and 27-36	
3	Christopher Menendez	CAM-2T	Capacity Cost Recovery True-Up (Jan – Dec. 2019).	6-11, 18-23(A-D), and 27-36	
4	Christopher Menendez	CAM-3T	Schedules A1 through A3, A6 and A12 for Dec 2019.	6-11, 18-23(A-D), and 27-36	
5	Christopher Menendez	CAM-4T	2019 Capital Structure and Cost Rates Applied to Capital Projects.	6-11, 18-23(A-D), and 27-36	
6	Christopher Menendez	CAM-2	Actual/Estimated True-up Schedules for period January – December 2020.	6-11, 18-23(A-D), and 27-36	
7	Christopher Menendez	CAM-3	Projection Factors for January - December 2021.	6-11, 18-23(A-D), and 27-36	
8	Mary Ingle Lewter	MIL-1T	Calculation of GPIF Reward for January - December 2019.	16 and 17	

9	Mary Ingle Lewter	MIL-1P	GPIF Targets/Ranges Schedules for January – December 2021.	16 and 17	
FLORIDA POWER & LIGHT COMPANY – DIRECT					
10	R.B.Deaton	RBD-1	2019 FCR Final True-Up Calculation.	8, 10	
11	R.B.Deaton	RBD-2	2019 CCR Final True-Up Calculation. **Confidential DN. 01197-2020**	27, 29	
12	R.B.Deaton	RBD-3	2020 FCR Actual/Estimated True-Up Calculation.	9, 10	
13	R.B.Deaton	RBD-4	2020 CCR Actual/Estimated True-Up Calculation .	28, 29	
14	R.B.Deaton	RBD-5	2019 FCR Final True-Up Calculation REVISED.	8	
15	R.B.Deaton	RBD-6	Appendix II 2021 FCR Projections.	11, 18-22, 34-36	
16	R.B.Deaton	RBD-7	Appendix III 2021 CCR Projections.	24B, 30-36	
17	G.J. Yupp	GJY-1	2019 Incentive Mechanism Results. **Confidential DN. 01197-2020**	2B-2E	
18	G.J. Yupp	GJY-2	Appendix I Fuel Cost Recovery.	6-11 and 18	
19	C.R. Rote	CRR-1	Generating Performance Incentive Factor Performance Results for January 2019 through December 2019.	16	
20	C.R. Rote	CRR-2	Generating Performance Incentive Factor Performance Targets for January 2021 through December 2021.	17	

21	L. Fuentes	LF-1	2018 SoBRA Final Revenue Requirement Calculation.	2A, 24A	
22	E.J. Anderson	EJA-1	Revised 2018 SoBRA Factor/Refund Calculation.	2A, 24A	
23	E.J. Anderson	EJA-2	2018 SoBRA Prospective Adjustment for January 1, 2021.	2A, 24A	
24	E.J. Anderson	EJA-3	Projected Retail Base Revenues for January 1, 2021.	2A, 24A	
25	E.J. Anderson	EJA-4	Summary of Tariff Changes for January 1, 2021.	2A, 24A	
26	E.J. Anderson	EJA-5	Typical Bill Projections.	2A, 24A	
FLORIDA PUBLIC UTILITIES COMPANY – DIRECT					
27	Curtis D. Young	CDY-1	Final True Up Schedules (Schedules A, C1 and E1-B for FPUC's Divisions).	8	
28	Curtis D. Young	CDY-2	Estimated/Actual (Schedules El-A, El-B, and El-B1).	3A, 9	
29	Curtis D. Young	CDY-3	Revised Monthly True-Up for January through June 2020.	3A	
30	Curtis D. Young	CDY-4	Schedules E1, E1A, E2, E7, E8, E10 and Schedule A.	10, 11, 18, 19, 20, 21, 22, 34, 35, 36	
GULF POWER COMPANY – DIRECT					
31	Richard L. Hume	RLH-1	Calculation of Final True-Up January 2019 – December 2019. **Confidential DN. 01195-2020**	8, 27	
32	Richard L. Hume	RLH-2	A-Schedules December 2019.	8	

33	Richard L. Hume	RLH-3	Estimated Fuel True-Up January 2020 – December 2020. **Confidential DN. 04054-2020**	6, 9	
34	Richard L. Hume	RLH-4	Estimated Capacity True-up January 2020 – December 2020.	28	
35	Richard L. Hume	RLH-5	Projection January 2021 – December 2021. **Confidential DN. 05949-2020**	7, 10, 11, 18-22, 29-33	
36	Richard L. Hume	RLH-6	Hedging Information Report August 2019 – December 2019. **Confidential DN. 01856-2020, xref. 01745-2020**	4A	
37	Richard L. Hume	RLH-7	Hedging Information Report January 2020– March 2020. **Confidential DN. 04309-2020**	4A	
38	Richard L. Hume	RLH-8	Calculation of the stratified separation factors.	32	
39	Charles Rote	JAV-1	Gulf Power Company GPIF Results January 2019 – December 2019.	16	
40	Charles Rote	CR-1	Gulf Power Company GPIF Targets and Ranges January 2021 – December 2021.	17	

TAMPA ELECTRIC COMPANY – DIRECT					
41	M. Ashley Sizemore	MAS-1	Final True-up Capacity Cost Recovery January 2019 – December 2019; Final True-up Fuel Cost Recovery January 2019-December 2019; Actual Fuel True-up Compared to Original Estimates January 2019 – December 2019; Schedules A-1, A-2, A-6 through A-9, and A-12 January 2019 – December 2019; Capital Projects Approved for Fuel Clause Recovery January 2019 – December 2019.	6, 7, 8, 9, 10,11,18, 19, 20, 21, 22, 27, 28, 29, 30, 31, 32, 33, 34, 35	
42	M. Ashley Sizemore	MAS-2	Actual/Estimated True-Up Fuel Cost Recovery January 2020 – December 2020; Actual/Estimated True-Up Capacity Cost Recovery January 2020 – December 2020; Capital Projects Approved for Fuel Clause Recovery January 2020 – December 2020; Lake Hancock Stipulated Issue Fuel Savings January 2019 – December 2019.	6, 7, 8, 9, 10,11,18, 19, 20, 21, 22, 27, 28, 29, 30, 31, 32, 33, 34, 35	
43	M. Ashley Sizemore	MAS-3	Projected Capacity Cost Recovery January 2021 – December 2021; Projected Fuel Cost Recovery January 2021 – December 2021; Levelized and Tiered Fuel Rate January 2021 – December 2021.	6, 7, 8, 9, 10,11,18, 19, 20, 21, 22, 27, 28, 29, 30, 31, 32, 33, 34, 35	
44	Jeremy B. Cain	JBC-1	Final True-Up Generating Performance Incentive factor January 2019 – December 2019; Actual Unit Performance Data January 2019 – December 2019;.	16, 17, 18	

45	Jeremy B. Cain	JC-1	Generating Performance Incentive Factor January 2021 – December 2021; Summary of Generating Performance Incentive Factor Targets January 2021 – December 2021.	16, 17, 18	
46	John C. Heisey	JCH-1	Optimization Mechanism Results January 2019 – December 2019.	5A, 18	
STAFF – DIRECT					
47	Debra M. Dobiac	DMD-1	Auditor's Report-Hedging Activities.	4A	
STAFF HEARING EXHIBITS					
48	Deaton		Florida Power & Light Company's Responses to Staff's 2nd Set of Interrogatories No. 6. *[Bates Nos. 00001-00002]*	28-30	
49	Coffey		Florida Power & Light Company's Responses to Staff's 3rd Set of Interrogatories No. 8. *[Bates Nos. 00003-00004]*	2G, 9	
50	Coffey		Florida Power & Light Company's 2019 Response to Staff 5th set of Interrogatories No. 41. *[Bates Nos. 00005-00008]*	2F, 2G	
51	Coffey		Florida Power & Light Company's 2019 Response to Staff 2nd Production of Documents No. 3. Including additional files for No. 3 *[Bates Nos. 00009-00010]*	2F, 2G	

52	Sizemore		Tampa Electric Company's answers to Staff's Second Set of Interrogatories, No. 5. *[Bates Nos. 00011-00013]*	30	
HEARING EXHIBITS					
Exhibit Number	**Witness**	**Party**	**Description**		**Moved In/Due Date of Late Filed**
53	Coffey	OPC	Siemens Customer Final Report OPC Ex. 7C		Not Entered
54	Coffey	OPC	FPL RCE - Public Version OPC Ex. 8		
55	Coffey	OPC	Staff Interrogatory 41 Response OPC Ex. 2		
56	Coffey	OPC	St. Lucie 1 Generator Ground Fault Analysis OPC Ex. 3		
57	Coffey	OPC	Siemens Stator Ground Fault Report OPC Ex. 4C		Not Entered
58	Coffey	OPC	Ground Fault Root Cause Statement OPC Ex. 6C		Not Entered

Duke Energy Florida, LLC
Fuel Adjustment Clause
Summary of Actual True-Up Amount
January 2019 - December 2019

Line No.	Description	Contribution to Over/(Under) Recovery Period to Date
	KWH Sales:	
1	Jurisdictional kWh Sales - Difference	(126,624,064)
2	Non-Jurisdictional kWh Sales - Difference	(5,063,486)
3	Total System kWh Sales - Difference Schedule A2, pg 1 of 2, line B3	(131,687,550)
	System:	
4	Fuel and Net Purchased Power Costs - Difference Schedule A2, page 2 of 2, line C4	$ 16,803,034
	Jurisdictional:	
5	Fuel Revenues - Difference Schedule A2, page 2 of 2, line C3	($4,752,584)
6	Fuel and Net Purchased Power Costs - Difference Schedule A2, page 2 of 2, line C6 - C12 - C7	(26,619,006)
7	True-Up Amount for the Period	21,866,422
8	True-Up for the Prior Period Schedule A2, page 2 of 2, line C9	(202,879,590)
9	True-Up Collected/(Refunded) in Current Period	148,450,915
10	Interest Provision Schedule A2, page 2 of 2, line C8	(3,435,661)
11	Actual True-Up Ending Balance for the Period January 2019 through December 2019 Schedule A2, page 2 of 2, line C13	(35,997,914)
12	Estimated True-Up Ending Balance for the Period January 2019 through December 2019 as approved in Order No. PSC-2019-0484-FOF-EI	(14,462,684)
13	Total True-Up for the Period January 2019 through December 2019	$ (21,535,230)

Duke Energy Florida, LLC
Fuel Adjustment Clause
Calculation of Actual True-up
January 2019 - December 2019

			JAN ACTUAL	FEB ACTUAL	MAR ACTUAL	APR ACTUAL	MAY ACTUAL	JUN ACTUAL	6 MONTH SUB-TOTAL
A	1	Fuel Cost of System Generation	$ 109,976,964	$ 82,327,645	$ 91,917,642	$ 96,277,004	$ 109,917,691	$ 118,976,978	$ 609,393,924
	2	Fuel Cost of Power Sold	(3,100,010)	(1,478,546)	(2,257,015)	(2,883,465)	(4,252,385)	(9,623,682)	(23,595,103)
	3	Fuel Cost of Purchased Power	3,709,959	2,648,955	5,132,188	6,247,340	13,339,364	12,829,894	43,907,699
	3a	Demand and Non-Fuel Cost of Purchased Power	-	-	-	-	-	-	-
	3b	Energy Payments to Qualified Facilities	10,908,157	7,601,725	7,328,667	7,064,641	8,882,702	9,231,306	51,017,197
	4	Energy Cost of Economy Purchases	184,282	240,158	250,203	378,398	462,113	517,405	2,032,557
	5	Adjustments to Fuel Cost	1,304,334	1,209,489	1,202,751	1,198,907	1,197,017	1,196,947	7,309,445
	6	TOTAL FUEL & NET POWER TRANSACTIONS	122,983,686	92,549,425	103,574,435	108,282,824	129,546,501	133,128,847	690,065,719
		(Sum of Lines A1 Through A5)							
B	1	Jurisdictional MWH Sales	2,669,994	2,719,126	2,780,959	2,897,128	3,185,816	3,813,849	18,066,872
	2	Non-Jurisdictional MWH Sales	19,604	18,678	12,252	12,171	17,654	31,506	111,863
	3	TOTAL SALES (Lines B1 + B2)	2,689,597	2,737,803	2,793,209	2,909,299	3,203,472	3,845,355	18,178,735
	4	Jurisdictional % of Total Sales (Line B1/B3)	99.27%	99.32%	99.56%	99.58%	99.45%	99.18%	99.38%
C	1	Jurisdictional Fuel Recovery Revenue	104,760,834	106,246,246	108,046,001	112,815,219	125,936,532	152,625,203	710,430,035
		(Net of Revenue Taxes)							
	2	True-Up Provision	(12,370,910)	(12,370,910)	(12,370,910)	(12,370,910)	(12,370,910)	(12,370,910)	(74,225,459)
	2a	Incentive Provision	191,794	191,794	191,794	191,794	191,794	191,794	1,150,763
	3	FUEL REVENUE APPLICABLE TO PERIOD	92,581,718	94,067,131	95,866,885	100,636,103	113,757,416	140,446,088	637,355,338
		(Sum of Lines C1 Through C2a)							
	4	Fuel & Net Power Transactions (Line A6)	122,983,686	92,549,425	103,574,435	108,282,824	129,546,501	133,128,847	690,065,719
	5	Jurisdictional Total Fuel Costs & Net Power Transactions	122,123,752	91,951,342	103,153,768	107,864,698	128,877,798	132,082,083	686,053,442
		(Line A6 * Line B4 * Line Loss Multiplier)							
	6	Over/(Under) Recovery (Line 3 - Line 5)	(29,542,034)	2,115,788	(7,286,883)	(7,228,595)	(15,120,383)	8,364,005	(48,698,104)
	7	Interest Provision	(422,930)	(428,593)	(415,902)	(408,311)	(398,760)	(371,997)	(2,446,493)
	8	TOTAL ESTIMATED TRUE-UP FOR THE PERIOD	(29,964,964)	1,687,196	(7,702,784)	(7,636,906)	(15,519,143)	7,992,010	(51,144,594)
	9	Plus: Prior Period Balance	(202,879,590)	(202,879,590)	(202,879,590)	(202,879,590)	(202,879,590)	(202,879,590)	(202,879,590)
	10	Plus: Cumulative True-Up Provision	12,370,910	24,741,820	37,112,730	49,483,640	61,854,550	74,225,459	74,225,459
	11	Subtotal Prior Period True-up	(190,508,680)	(178,137,770)	(165,766,860)	(153,395,950)	(141,025,040)	(128,654,130)	(128,654,130)
	12	Regulatory Accounting Adjustment	-	-	-	-	-	-	-
	13	TOTAL TRUE-UP BALANCE	(220,473,645)	(206,415,540)	(201,747,415)	($197,013,412)	($200,161,645)	($179,798,727)	(179,798,727)

Docket No. 20200001-EI
Witness: Menendez
Exh bit No. (CAM-1T)
Sheet 3 of 6

Duke Energy Florida, LLC
Fuel Adjustment Clause
Calculation of Actual True-up
January 2019 - December 2019

			JUL ACTUAL	AUG ACTUAL	SEPT ACTUAL	OCT ACTUAL	NOV ACTUAL	DEC ACTUAL	12 MONTH PERIOD
A	1	Fuel Cost of System Generation	$ 116,352,775	$ 111,383,035	$ 109,757,451	$ 111,492,910	$ 92,962,591	$ 79,539,979	$ 1,230,882,664
	2	Fuel Cost of Power Sold	(9,198,657)	(7,706,633)	(7,953,736)	(7,810,829)	(3,794,717)	(1,762,479)	(61,822,154)
	3	Fuel Cost of Purchased Power	9,140,098	9,154,942	10,622,880	11,647,112	6,052,335	3,380,078	93,905,144
	3a	Demand and Non-Fuel Cost of Purchased Power	-	-	-	-	-	-	-
	3b	Energy Payments to Qualified Facilities	8,368,247	8,243,369	7,521,729	7,434,207	8,196,466	8,695,897	99,477,111
	4	Energy Cost of Economy Purchases	228,260	1,296,269	218,744	1,312,555	486,037	340,062	5,914,484
	5	Adjustments to Fuel Cost	2,035,570	1,180,850	2,907,277	1,171,323	1,165,746	4,157,828	19,928,039
	6	TOTAL FUEL & NET POWER TRANSACTIONS	126,926,293	123,551,832	123,074,345	125,247,277	105,068,459	94,351,364	1,388,285,289
		(Sum of Lines A1 Through A5)							
B	1	Jurisdictional MWH Sales	3,754,506	3,871,530	3,949,701	3,477,370	3,305,813	2,761,551	39,187,343
	2	Non-Jurisdictional MWH Sales	26,823	31,195	19,715	21,476	14,840	12,087	238,000
	3	TOTAL SALES (Lines B1 + B2)	3,781,329	3,902,725	3,969,416	3,498,846	3,320,654	2,773,639	39,425,344
	4	Jurisdictional % of Total Sales (Line B1/B3)	99.29%	99.20%	99.50%	99.39%	99.55%	99.56%	99.40%
C	1	Jurisdictional Fuel Recovery Revenue	150,700,542	154,825,196	158,407,343	138,276,326	130,267,974	105,460,463	1,548,367,879
		(Net of Revenue Taxes)							
	2	True-Up Provision	(12,370,910)	(12,370,910)	(12,370,910)	(12,370,910)	(12,370,910)	(12,370,910)	(148,450,915)
	2a	Incentive Provision	191,794	191,794	191,794	191,794	191,794	191,794	2,301,526
	3	FUEL REVENUE APPLICABLE TO PERIOD	138,521,426	142,646,081	146,228,227	126,097,210	118,088,859	93,281,347	1,402,218,490
		(Sum of Lines C1 Through C2a)							
	4	Fuel & Net Power Transactions (Line A6)	126,926,293	123,551,832	123,074,345	125,247,277	105,068,459	94,351,364	1,388,285,291
	5	Jurisdictional Total Fuel Costs & Net Power Transactions	126,067,964	122,605,089	122,500,609	124,525,594	104,631,214	93,968,157	1,380,352,070
		(Line A6 * Line B4 * Line Loss Multiplier)							
	6	Over/(Under) Recovery (Line 3 - Line 5)	12,453,462	20,040,991	23,727,618	1,571,617	13,457,645	(686,810)	21,866,420
	7	Interest Provision	(307,991)	(240,602)	(176,504)	(121,129)	(84,030)	(58,911)	(3,435,661)
	8	TOTAL ESTIMATED TRUE-UP FOR THE PERIOD	12,145,471	19,800,389	23,551,114	1,450,488	13,373,615	(745,721)	18,430,759
	9	Plus: Prior Period Balance	(202,879,590)	(202,879,590)	(202,879,590)	(202,879,590)	(202,879,590)	(202,879,590)	(202,879,590)
	10	Plus: Cumulative True-Up Provision	86,596,369	98,967,279	111,338,188	123,709,098	136,080,007	148,450,917	148,450,917
	11	Subtotal Prior Period True-up	(116,283,221)	(103,912,311)	(91,541,402)	(79,170,492)	(66,799,583)	(54,428,673)	(54,428,673)
	12	Regulatory Accounting Adjustment	-	-	-	-	-	-	-
	13	TOTAL TRUE-UP BALANCE	($155,282,347)	($123,111,048)	($87,189,024)	($73,367,626)	($47,623,102)	($35,997,914)	(35,997,914)

Docket No. 20200001-EI
Witness: Menendez
Exhibit No. (CAM-1T)
Sheet 4 of 6

Duke Energy Florida, LLC
Fuel Adjustment Clause
Calculation of 2018 Actual/Estimated True-up
January 2019 - December 2019 (Filed July 26, 2019)

			JAN ACTUAL	FEB ACTUAL	MAR ACTUAL	APR ACTUAL	MAY ACTUAL	JUN ACTUAL	6 MONTH SUB-TOTAL
A	1	Fuel Cost of System Generation	$ 109,976,964	$ 82,327,645	$ 91,917,642	$ 96,277,004	$ 109,917,691	$ 118,976,978	$ 609,393,924
	2	Fuel Cost of Power Sold	(3,100,010)	(1,478,546)	(2,257,015)	(2,883,465)	(4,252,385)	(9,623,682)	(23,595,103)
	3	Fuel Cost of Purchased Power	3,709,959	2,648,955	5,132,188	6,247,340	13,339,364	12,829,894	43,907,699
	3a	Demand and Non-Fuel Cost of Purchased Power	-	-	-	-	-	-	-
	3b	Energy Payments to Qualified Facilities	10,908,157	7,601,725	7,328,667	7,064,641	8,882,702	9,231,306	51,017,197
	4	Energy Cost of Economy Purchases	184,282	240,158	250,203	378,398	462,113	517,405	2,032,557
	5	Adjustments to Fuel Cost	1,304,334	1,209,489	1,202,751	1,198,907	1,197,017	1,196,947	7,309,445
	6	TOTAL FUEL & NET POWER TRANSACTIONS (Sum of Lines A1 Through A5)	122,983,686	92,549,425	103,574,435	108,282,824	129,546,501	133,128,847	690,065,719
B	1	Jurisdictional MWH Sales	2,669,994	2,719,125	2,780,959	2,897,129	3,185,818	3,813,849	18,066,873
	2	Non-Jurisdictional MWH Sales	19,604	18,678	12,252	12,171	17,654	31,506	111,863
	3	TOTAL SALES (Lines B1 + B2)	2,689,597	2,737,803	2,793,210	2,909,299	3,203,472	3,845,354	18,178,736
	4	Jurisdictional % of Total Sales (Line B1/B3)	99.27%	99.32%	99.56%	99.58%	99.45%	99.18%	99.38%
C	1	Jurisdictional Fuel Recovery Revenue (Net of Revenue Taxes)	104,760,834	106,246,246	108,046,001	112,815,219	125,936,532	152,625,203	710,430,035
	2	True-Up Provision	(12,370,910)	(12,370,910)	(12,370,910)	(12,370,910)	(12,370,910)	(12,370,910)	(74,225,460)
	2a	Incentive Provision	191,794	191,794	191,794	191,794	191,794	191,794	1,150,764
	3	FUEL REVENUE APPLICABLE TO PERIOD (Sum of Lines C1 Through C2a)	92,581,718	94,067,130	95,866,885	100,636,103	113,757,416	140,446,087	637,355,339
	4	Fuel & Net Power Transactions (Line A6)	122,983,686	92,549,425	103,574,435	108,282,824	129,546,501	133,128,847	690,065,719
	5	Jurisdictional Total Fuel Costs & Net Power Transactions (Line A6 * Line B4 * Line Loss Multiplier)	122,123,752	91,951,342	103,153,768	107,864,698	128,877,798	132,082,083	686,053,442
	6	Over/(Under) Recovery (Line 3 - Line 5)	(29,542,034)	2,115,788	(7,286,883)	(7,228,595)	(15,120,383)	8,364,004	(48,698,103)
	7	Interest Provision	(422,930)	(428,593)	(415,902)	(408,311)	(398,760)	(371,997)	(2,446,493)
	8	TOTAL ESTIMATED TRUE-UP FOR THE PERIOD	(29,964,965)	1,687,195	(7,702,785)	(7,636,906)	(15,519,143)	7,992,011	(51,144,593)
	9	Plus: Prior Period Balance	(202,879,590)	(202,879,590)	(202,879,590)	(202,879,590)	(202,879,590)	(202,879,590)	(202,879,590)
	10	Plus: Cumulative True-Up Provision	12,370,910	24,741,820	37,112,730	49,483,640	61,854,550	74,225,460	74,225,460
	11	Subtotal Prior Period True-up	(190,508,680)	(178,137,770)	(165,766,860)	(153,395,950)	(141,025,040)	(128,654,130)	(128,654,130)
	12	Regulatory Accounting Adjustment	-	-	-	-	-	-	-
	13	TOTAL TRUE-UP BALANCE	($220,473,645)	($206,415,539)	($201,747,415)	($197,013,411)	($200,161,644)	($179,798,727)	(179,798,727)

Docket No. 20200001-EI
Witness: Menendez
Exhibit No. (CAM-1T)
Sheet 5 of 6

Duke Energy Florida, LLC
Fuel Adjustment Clause
Calculation of 2017 Actual/Estimated True-up
January 2019 - December 2019 (Filed July 26, 2019)

			JUL ESTIMATED	AUG ESTIMATED	SEPT ESTIMATED	OCT ESTIMATED	NOV ESTIMATED	DEC ESTIMATED	12 MONTH PERIOD
A	1	Fuel Cost of System Generation	$ 117,430,448	$ 116,590,525	$ 108,507,217	$ 95,523,571	$ 87,935,869	$ 92,653,910	$ 1,228,035,464
	2	Fuel Cost of Power Sold	(8,107,008)	(8,047,357)	(6,900,753)	(6,494,023)	(3,667,686)	(4,267,921)	(61,079,851)
	3	Fuel Cost of Purchased Power	8,184,838	6,876,582	6,779,581	7,136,160	2,844,662	1,106,770	76,836,292
	3a	Demand and Non-Fuel Cost of Purchased Power	-	-	-	-	-	-	-
	3b	Energy Payments to Qualified Facilities	10,332,497	10,289,444	9,155,724	9,742,112	9,860,682	10,026,097	110,423,752
	4	Energy Cost of Economy Purchases	188,238	123,884	128,246	137,662	89,384	223,111	2,923,082
	5	Adjustments to Fuel Cost	1,185,271	1,181,837	1,172,013	1,168,362	1,164,477	1,162,111	14,343,516
	6	TOTAL FUEL & NET POWER TRANSACTIONS (Sum of Lines A1 Through A5)	129,214,284	127,014,915	118,842,028	107,213,844	98,227,388	100,904,077	1,371,482,256
B	1	Jurisdictional MWH Sales	3,840,042	3,872,711	3,972,711	3,626,916	3,055,736	2,878,978	39,313,967
	2	Non-Jurisdictional MWH Sales	36,625	37,341	16,716	14,981	11,631	13,906	243,064
	3	TOTAL SALES (Lines B1 + B2)	3,876,667	3,910,052	3,989,428	3,641,897	3,067,367	2,892,884	39,557,031
	4	Jurisdictional % of Total Sales (Line B1/B3)	99.06%	99.05%	99.58%	99.59%	99.62%	99.52%	99.39%
C	1	Jurisdictional Fuel Recovery Revenue (Net of Revenue Taxes)	152,301,622	153,597,318	157,563,471	143,848,708	121,194,902	114,184,412	1,553,120,468
	2	True-Up Provision	(12,370,910)	(12,370,910)	(12,370,910)	(12,370,910)	(12,370,910)	(12,370,910)	(148,450,915)
	2a	Incentive Provision	191,794	191,794	191,794	191,794	191,794	191,792	2,301,526
	3	FUEL REVENUE APPLICABLE TO PERIOD (Sum of Lines C1 Through C2a)	140,122,506	141,418,202	145,384,355	131,669,592	109,015,786	102,005,294	1,406,971,079
	4	Fuel & Net Power Transactions (Line A6)	129,214,284	127,014,915	118,842,028	107,213,844	98,227,388	100,904,077	1,371,482,256
	5	Jurisdictional Total Fuel Costs & Net Power Transactions (Line A6 * Line B4 * Line Loss Multiplier)	128,043,189	125,851,048	118,383,128	106,810,571	97,887,395	100,453,881	1,363,482,653
	6	Over/(Under) Recovery (Line 3 - Line 5)	12,079,317	15,567,153	27,001,228	24,859,021	11,128,391	1,551,413	43,488,421
	7	Interest Provision	(328,337)	(277,639)	(212,216)	(137,572)	(78,343)	(41,829)	(3,522,429)
	8	TOTAL ESTIMATED TRUE-UP FOR THE PERIOD	11,750,980	15,289,514	26,789,011	24,721,449	11,050,048	1,509,584	39,965,991
	9	Plus: Prior Period Balance	(202,879,590)	(202,879,590)	(202,879,590)	(202,879,590)	(202,879,590)	(202,879,590)	(202,879,590)
	10	Plus: Cumulative True-Up Provision	86,596,370	98,967,280	111,338,190	123,709,100	136,080,010	148,450,915	148,450,915
	11	Subtotal Prior Period True-up	(116,283,220)	(103,912,310)	(91,541,400)	(79,170,490)	(66,799,580)	(54,428,675)	(54,428,675)
	12	Regulatory Accounting Adjustment	-	-	-	-	-	-	-
	13	TOTAL TRUE-UP BALANCE	($155,676,837)	($128,016,413)	($88,856,491)	($51,764,131)	($28,343,173)	($14,462,684)	(14,462,684)

Duke Energy Florida, LLC
Fuel Adjustment Clause
Fuel and Net Power Cost Variance Analysis
January 2019 - December 2019

	(A) Energy Source	(B) MWH Variances	(C) Heat Rate Variances	(D) Price Variances	(E) Total
1	Heavy Oil	0	0	0	0
2	Light Oil	11,504,129	(2,882,194)	(801,797)	7,820,138
3	Coal	28,353,368	(5,304,043)	(9,731,870)	13,317,456
4	Gas	(31,666,331)	30,666,943	(17,291,007)	(18,290,394)
5	Nuclear	0	0	0	0
6	Other Fuel	0	0	0	0
7	Total Generation	8,191,167	22,480,707	(27,824,674)	2,847,200
8	Firm Purchases	15,032,871	0	2,035,981	17,068,852
9	Economy Purchases	2,743,998	0	247,404	2,991,402
10	Schedule E Purchases	0	0	0	0
11	Qualifying Facilities	(9,613,068)	0	(1,333,573)	(10,946,641)
12	Total Purchases	8,163,802	0	949,811	9,113,613
13	Economy Sales	0	0	0	0
14	Other Power Sales	(444,214)	0	843,831	399,616
15	Supplemental Sales	(5,056,605)	0	3,914,688	(1,141,918)
16	Total Sales	(5,500,820)	0	4,758,518	(742,302)
17	Total Fuel and Net Power Cost Variance	10,854,149	22,480,707	(22,116,344)	11,218,511

Duke Energy Florida, LLC
Capacity Cost Recovery Clause
Summary of Actual True-Up Amount
January 2019 - December 2019

Line No.	Description	Actual	Actual/Estimated Filing	Variance
	Jurisdictional:			
1	Capacity Cost Recovery Revenues Sheet 2 of 3, Line 42	$ 443,945,577	$ 447,674,132	$ (3,728,555)
2	Capacity Cost Recovery Expenses Sheet 2 of 3, Line 38	442,043,248	444,991,352	(2,948,104)
3	Plus/(Minus) Interest Provision Sheet 2 of 3, Line 45	(6,208)	11,121	(17,330)
4	Sub-Total Current Period Over/(Under) Recovery Sheet 2 of 3, Line 46	$ 1,896,122	$ 2,693,901	$ (797,779)
5	Prior Period True-up - January through December 2018 - Over/(Under) Recovery Sheet 2 of 3, Line 47	15,765,080	15,765,080	0
6	Prior Period True-up - January through December 2018 - (Refunded)/Collected Sheet 2 of 3, Line 48	(16,610,472)	(16,610,472)	0
7	Actual True-Up Ending Balance Over/(Under) Recovery for the Period January through December 2019 Sheet 2 of 3, Line 50	$ 1,050,730	$ 1,848,509	$ (797,779)
8	Estimated True-Up Ending Balance for the Period Included in the Filing of Levelized Fuel Cost Factors January through December 2020 per Order No. PSC-2019-0484-FOF-EI (Sheet 3 of 3, Line 46)	1,848,509		
9	Total Over/(Under) Recovery for the Period January through December 2019 (Line 7 - Line 8)	$ (797,779)		

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20200001-EI EXHIBIT: 3
PARTY: DUKE ENERGY FLORIDA – DIRECT
DESCRIPTION: Christopher Menendez CAM-2T

Docket No. 20200001-EI
Witness: Menendez
Exh bit No. (CAM-2T)
Sheet 2 of 3

Duke Energy Florida, LLC
Capacity Cost Recovery Clause
Calculation of Actual True-Up
January 2019 - December 2019

		JAN ACTUAL	FEB ACTUAL	MAR ACTUAL	APR ACTUAL	MAY ACTUAL	JUN ACTUAL	JUL ACTUAL	AUG ACTUAL	SEPT ACTUAL	OCT ACTUAL	NOV ACTUAL	DEC ACTUAL	Total
1	**Base Production Level Capacity Costs**													
2	Orange Cogen (ORANGECO)	5,600,934	5,600,934	5,600,934	5,600,934	5,600,934	5,600,934	5,600,934	5,600,934	5,600,934	5,600,934	5,516,015	5,600,934	67,126,287
3	Orlando Cogen Limited (ORLACOGL)	5,636,162	5,636,162	5,636,162	5,636,162	5,636,162	5,636,162	5,636,162	5,636,162	5,636,162	5,636,162	5,636,162	5,636,162	67,633,943
4	Pasco County Resource Recovery (PASCOUNT)	2,019,170	2,019,170	2,019,170	2,019,170	2,019,170	2,019,170	2,019,170	2,019,170	2,019,170	2,019,170	2,019,170	2,019,170	24,230,040
5	Pinellas County Resource Recovery (PINCOUNT)	4,806,503	4,806,503	4,806,503	4,806,503	4,806,503	4,806,503	4,806,503	4,806,503	4,806,503	4,806,503	4,806,503	4,806,503	57,678,030
6	Polk Power Partners, L.P. (MULBERRY/ROYSTER)	7,693,916	7,693,916	7,693,916	7,693,916	7,693,916	7,693,916	7,693,916	7,693,916	7,693,916	7,693,916	7,693,916	7,693,916	92,326,988
7	Wheelabrator Ridge Energy, Inc. (RIDGEGEN)	800,946	0	0	0	0	0	0	0	0	0	0	0	800,946
8	US EcoGen	0	0	0	0	0	0	0	0	0	0	0	0	0
9	Subtotal - Base Level Capacity Costs	26,557,630	25,756,684	25,756,684	25,756,684	25,756,684	25,756,684	25,756,684	25,756,684	25,756,684	25,756,684	25,671,766	25,756,684	309,796,234
10	Base Production Jurisdictional Respons bility	92.885%	92.885%	92.885%	92.885%	92.885%	92.885%	92.885%	92.885%	92.885%	92.885%	92.885%	92.885%	
11	Base Level Jurisdictional Capacity Costs	24,668,054	23,924,096	23,924,096	23,924,096	23,924,096	23,924,096	23,924,096	23,924,096	23,924,096	23,924,096	23,845,219	23,924,096	287,754,233
12	**Intermediate Production Level Capacity Costs**													
13	Southern Franklin	4,611,942	4,802,362	2,752,978	2,755,639	2,814,130	5,254,911	6,502,231	6,128,473	4,721,360	2,755,745	2,747,786	3,583,491	49,431,048
14	Schedule H Capacity Sales	(48,411)	0	(64,548)	0	0	(114,031)	6,705	0	131,000	0	384,713	201,135	496,563
15	Subtotal - Intermediate Level Capacity Costs	4,563,531	4,802,362	2,688,430	2,755,639	2,814,130	5,140,880	6,508,936	6,128,473	4,852,360	2,755,745	3,132,499	3,784,626	49,927,611
16	Intermediate Production Jurisdictional Responsibility	72.703%	72.703%	72.703%	72.703%	72.703%	72.703%	72.703%	72.703%	72.703%	72.703%	72.703%	72.703%	
17	Intermediate Level Jurisdictional Capacity Costs	3,317,824	3,491,461	1,954,569	2,003,433	2,045,957	3,737,574	4,732,192	4,455,584	3,527,811	2,003,509	2,277,420	2,751,537	36,298,870
18	**Peaking Production Level Capacity Costs**													
19	Shady Hills	1,976,940	1,976,940	1,412,100	1,366,200	1,912,680	3,888,000	3,888,000	3,888,000	(2,073,600)	1,366,200	1,351,582	1,973,160	22,926,202
20	Vandolah	2,919,279	2,891,051	1,947,614	1,942,582	2,793,653	5,773,604	5,928,134	5,787,984	2,747,117	1,940,621	2,042,583	2,984,299	39,698,523
21	Other	-	-	-	-	-	-	-	-	-	-	-	-	
22	Subtotal - Peaking Level Capacity Costs	4,896,219	4,867,991	3,359,714	3,308,782	4,706,333	9,661,604	9,816,134	9,675,984	673,517	3,306,821	3,394,165	4,957,459	62,624,724
23	Peaking Production Jurisdictional Respons bility	95.924%	95.924%	95.924%	95.924%	95.924%	95.924%	95.924%	95.924%	95.924%	95.924%	95.924%	95.924%	
24	Peaking Level Jurisdictional Capacity Costs	4,696,650	4,669,572	3,222,772	3,173,916	4,514,503	9,267,797	9,416,028	9,281,591	646,064	3,172,035	3,255,818	4,755,393	60,072,141
25	**Other Capacity Costs**													
26	Retail Wheeling	(45,534)	(8,443)	(35,373)	(39,200)	(57,327)	(29,146)	(30,224)	(2,595)	(14,622)	(443)	(33,247)	(963)	(297,116)
27	Ridge Generating Station L.P. Termination [1]	-	750,770	747,221	743,672	740,123	736,573	730,453	726,952	723,451	719,950	716,449	696,212	8,031,827
28	SoBRA True-Up - Hamilton [2]	-	-	-	-	-	-	-	-	(478,334)	-	-	-	(478,334)
29	Total Other Capacity Costs	(45,534)	742,327	711,848	704,472	682,796	707,428	700,229	724,357	230,495	719,507	683,202	695,250	7,256,377
30	**Total Capacity Costs (Line 11+17+24+29)**	32,636,994	32,827,456	29,813,285	29,805,916	31,167,351	37,636,895	38,772,545	38,385,628	28,328,466	29,819,146	30,061,660	32,126,276	391,381,620
31														
32	**Nuclear Cost Recovery Clause**													
33	CR3 Uprate Costs [3]	3,775,626	3,753,198	3,730,770	3,708,343	3,685,916	3,663,488	3,641,061	3,618,633	3,596,207	3,573,779	3,551,352	3,483,417	43,781,791
34	**Total Recoverable Nuclear Costs**	3,775,626	3,753,198	3,730,770	3,708,343	3,685,916	3,663,488	3,641,061	3,618,633	3,596,207	3,573,779	3,551,352	3,483,417	43,781,791
35														
36	**ISFSI Revenue Requirement** [4]	573,320	573,320	573,320	573,320	573,320	573,320	573,320	573,320	573,320	573,320	573,320	573,320	6,879,837
37														
38	**Total Recov Capacity & Nuclear Costs (Line 29+34+36)**	36,985,939	37,153,974	34,117,376	34,087,579	35,426,587	41,873,703	42,986,926	42,577,581	32,497,993	33,966,246	34,186,331	36,183,013	442,043,248
39	**Capacity Revenues:**													
40	Capacity Cost Recovery Revenues (net of tax)	29,661,483	30,804,405	30,389,686	31,169,336	34,653,964	41,304,162	40,754,509	42,096,759	42,539,408	37,590,498	36,198,432	30,172,463	427,335,104
41	Prior Period True-Up Provision Over/(Under) Recovery	1,384,206	1,384,206	1,384,206	1,384,206	1,384,206	1,384,206	1,384,206	1,384,206	1,384,206	1,384,206	1,384,206	1,384,206	16,610,473
42	Current Period CCR Revenues (net of tax)	31,045,689	32,188,611	31,773,892	32,553,542	36,038,171	42,688,368	42,138,715	43,480,965	43,923,614	38,974,705	37,582,638	31,556,669	443,945,577
43	**True-Up Provision**													
44	True-Up Provision - Over/(Under) Recov (Line 42-38)	(5,940,250)	(4,965,363)	(2,343,483)	(1,534,037)	611,583	814,665	(848,211)	903,384	11,425,621	5,008,459	3,396,306	(4,626,344)	1,902,330
45	Interest Provision for the Month	24,206	10,633	535	(6,274)	(9,873)	(10,962)	(12,889)	(14,488)	(6,063)	4,859	8,397	5,711	(6,208)
46	Current Cycle Balance - Over/(Under)	(5,916,044)	(10,870,774)	(13,213,723)	(14,754,034)	(14,152,324)	(13,348,621)	(14,209,721)	(13,320,825)	(1,901,267)	3,112,052	6,516,755	1,896,122	1,896,122
47	Prior Period Balance - Over/(Under) Recovered	15,765,080	14,380,876	12,996,669	11,612,462	10,228,256	8,844,050	7,459,844	6,075,638	4,691,432	3,307,226	1,923,020	538,814	15,765,080
48	Prior Period Cumulative True-Up Collected/(Refunded)	(1,384,206)	(1,384,206)	(1,384,206)	(1,384,206)	(1,384,206)	(1,384,206)	(1,384,206)	(1,384,206)	(1,384,206)	(1,384,206)	(1,384,206)	(1,384,206)	(16,610,472)
49	Prior Period True-up Balance - Over/(Under)	14,380,874	12,996,670	11,612,462	10,228,256	8,844,050	7,459,844	6,075,638	4,691,432	3,307,226	1,923,020	538,814	(845,392)	(845,392)
50	**Net Capacity True-up Over/(Under) (Line 46+49)**	8,464,830	2,125,894	(1,601,261)	(4,525,778)	(5,308,275)	(5,888,778)	(8,134,083)	(8,629,393)	1,405,959	5,035,071	7,055,568	1,050,730	1,050,730

[1] Approved in Commission Order No. PSC-2018-0532-PAA-EQ.

Docket No. 20200001-EI
Witness: Menendez
Exhibit No. (CAM-2T)
Sheet 3 of 3

Duke Energy Florida, LLC
Capacity Cost Recovery Clause
Calculation of Actual/Estimated True-Up
January 2019 - December 2019 (Filed July 26, 2019)

		JAN ACTUAL	FEB ACTUAL	MAR ACTUAL	APR ACTUAL	MAY ACTUAL	JUN ACTUAL	JUL ESTIMATED	AUG ESTIMATED	SEPT ESTIMATED	OCT ESTIMATED	NOV ESTIMATED	DEC ESTIMATED	Total
1	**Base Production Level Capacity Costs**													
2	Orange Cogen (ORANGECO)	5,600,934	5,600,934	5,600,934	5,600,934	5,600,934	5,600,934	5,600,934	5,600,934	5,600,934	5,600,934	5,600,934	5,600,934	67,211,204
3	Orlando Cogen Limited (ORLACOGL)	5,636,162	5,636,162	5,636,162	5,636,162	5,636,162	5,636,162	5,636,162	5,636,162	5,636,162	5,636,162	5,636,162	5,636,162	67,633,942
4	Pasco County Resource Recovery (PASCOUNT)	2,019,170	2,019,170	2,019,170	2,019,170	2,019,170	2,019,170	2,019,170	2,019,170	2,019,170	2,019,170	2,019,170	2,019,170	24,230,040
5	Pinellas County Resource Recovery (PINCOUNT)	4,806,503	4,806,503	4,806,503	4,806,503	4,806,503	4,806,503	4,806,503	4,806,503	4,806,503	4,806,503	4,806,503	4,806,503	57,678,030
6	Polk Power Partners, L.P. (MULBERRY/ROYSTER)	7,693,916	7,693,916	7,693,916	7,693,916	7,693,916	7,693,916	7,693,915	7,693,915	7,693,915	7,693,915	7,693,915	7,693,915	92,326,986
7	Wheelabrator Ridge Energy, Inc. (RIDGEGEN)	800,946	0	0	0	0	0	0	0	0	0	0	0	800,946
8	US EcoGen	0	0	0	0	0	0	0	0	0	0	0	0	0
9	Subtotal - Base Level Capacity Costs	26,557,630	25,756,684	25,756,684	25,756,684	25,756,684	25,756,684	25,756,683	25,756,683	25,756,683	25,756,683	25,756,683	25,756,683	309,881,148
10	Base Production Jurisdictional Responsibility	92.885%	92.885%	92.885%	92.885%	92.885%	92.885%	92.885%	92.885%	92.885%	92.885%	92.885%	92.885%	
11	Base Level Jurisdictional Capacity Costs	24,668,054	23,924,096	23,924,096	23,924,096	23,924,096	23,924,096	23,924,095	23,924,095	23,924,095	23,924,095	23,924,095	23,924,095	287,833,104
12	**Intermediate Production Level Capacity Costs**													
13	Southern Franklin	4,611,942	4,802,362	2,752,978	2,755,639	2,814,130	5,254,911	6,374,293	6,374,293	4,712,941	2,774,697	2,774,697	3,605,373	49,608,256
14	Schedule H Capacity Sales	(48,411)	-	(64,548)	-	-	(114,031)	-	-	-	-	-	-	(226,990)
15	Subtotal - Intermediate Level Capacity Costs	4,563,531	4,802,362	2,688,430	2,755,639	2,814,130	5,140,880	6,374,293	6,374,293	4,712,941	2,774,697	2,774,697	3,605,373	49,381,266
16	Intermediate Production Jurisdictional Respons bility	72.703%	72.703%	72.703%	72.703%	72.703%	72.703%	72.703%	72.703%	72.703%	72.703%	72.703%	72.703%	
17	Intermediate Level Jurisdictional Capacity Costs	3,317,824	3,491,461	1,954,569	2,003,433	2,045,957	3,737,574	4,634,302	4,634,302	3,426,450	2,017,288	2,017,288	2,621,214	35,901,661
18	**Peaking Production Level Capacity Costs**													
19	Shady Hills	1,976,940	1,976,940	1,412,100	1,366,200	1,912,680	3,888,000	3,901,517	3,901,517	1,820,708	1,370,803	1,370,803	1,978,175	26,876,383
20	Vandolah (NSG)	2,919,279	2,891,051	1,947,614	1,942,582	2,793,653	5,773,604	5,536,005	5,491,562	2,628,284	1,936,075	1,980,519	2,786,429	38,626,658
21	Other	-	-	-	-	-	-	-	-	-	-	-	-	-
22	Subtotal - Peaking Level Capacity Costs	4,896,219	4,867,991	3,359,714	3,308,782	4,706,333	9,661,604	9,437,522	9,393,079	4,448,992	3,306,878	3,351,322	4,764,603	65,503,041
23	Peaking Production Jurisdictional Responsibility	95.924%	95.924%	95.924%	95.924%	95.924%	95.924%	95.924%	95.924%	95.924%	95.924%	95.924%	95.924%	
24	Peaking Level Jurisdictional Capacity Costs	4,696,650	4,669,572	3,222,772	3,173,916	4,514,503	9,267,797	9,052,849	9,010,217	4,267,651	3,172,090	3,214,722	4,570,398	62,833,137
25	**Other Capacity Costs**													
26	Retail Wheeling	(45,534)	(8,443)	(35,373)	(39,200)	(57,327)	(29,146)	(27,612)	(34,680)	(22,418)	(10,341)	(6,562)	(15,612)	(332,248)
27	Ridge Generating Station L.P. Termination [1]	-	750,770	747,221	743,672	740,123	736,573	730,453	726,952	723,451	719,950	716,449	712,948	8,048,562
28	Total Other Capacity Costs	(45,534)	742,327	711,848	704,472	682,796	707,428	702,842	692,272	701,033	709,609	709,887	697,335	7,716,315
29	**Total Capacity Costs (Line 11+17+24+28)**	32,636,994	32,827,456	29,813,286	29,805,916	31,167,352	37,636,894	38,314,088	38,260,887	32,319,229	29,823,082	29,865,992	31,813,043	394,284,216
30	**Nuclear Cost Recovery Clause**													
31	CR3 Uprate Costs [2]	3,775,626	3,753,198	3,730,770	3,708,343	3,685,916	3,663,488	3,641,061	3,618,633	3,596,207	3,573,779	3,551,352	3,528,924	43,827,298
32	**Total Recoverable Nuclear Costs**	3,775,626	3,753,198	3,730,770	3,708,343	3,685,916	3,663,488	3,641,061	3,618,633	3,596,207	3,573,779	3,551,352	3,528,924	43,827,298
33	**ISFSI Revenue Requirement [3]**	573,320	573,320	573,320	573,320	573,320	573,320	573,320	573,320	573,320	573,320	573,320	573,320	6,879,837
34	**Total Recov Capacity & Nuclear Costs (Line 29+32+33)**	36,985,939	37,153,974	34,117,376	34,087,579	35,426,587	41,873,703	42,528,468	42,452,840	36,488,756	33,970,181	33,990,663	35,915,287	444,991,352
35	**Capacity Revenues**													
36	Capacity Cost Recovery Revenues (net of tax)	29,661,483	30,804,405	30,389,686	31,169,336	34,653,964	41,304,162	42,125,264	42,483,642	43,580,645	39,787,264	33,521,424	31,582,385	431,063,659
37	Prior Period True-Up Provision Over/(Under) Recovery	1,384,206	1,384,206	1,384,206	1,384,206	1,384,206	1,384,206	1,384,206	1,384,206	1,384,206	1,384,206	1,384,206	1,384,206	16,610,473
38	**Current Period Revenues (net of tax)**	31,045,689	32,188,611	31,773,892	32,553,542	36,038,171	42,688,368	43,509,470	43,867,848	44,964,851	41,171,470	34,905,630	32,966,591	447,674,132
39	**True-Up Provision**													
40	True-Up Provision - Over/(Under) Recov (Line 38-34)	(5,940,250)	(4,965,363)	(2,343,483)	(1,534,037)	611,583	814,665	981,002	1,415,008	8,476,095	7,201,289	914,967	(2,948,696)	2,682,780
41	Interest Provision for the Month	24,206	10,633	535	(6,274)	(9,873)	(10,962)	(6,166)	(6,142)	802	6,504	6,050	1,810	11,121
42	Current Cycle Balance - Over/(Under)	(5,916,044)	(10,870,774)	(13,213,724)	(14,754,035)	(14,152,325)	(13,348,622)	(12,373,786)	(10,964,920)	(2,488,023)	4,719,769	5,640,786	2,693,900	2,693,900
43	Prior Period Balance - Over/(Under) Recovered	15,765,080	15,765,080	15,765,080	15,765,080	15,765,080	15,765,080	15,765,080	15,765,080	15,765,080	15,765,080	15,765,080	15,765,080	15,765,080
44	Prior Period Cumulative True-Up Collected/(Refunded)	(1,384,206)	(2,768,412)	(4,152,618)	(5,536,824)	(6,921,030)	(8,305,235)	(9,689,442)	(11,073,648)	(12,457,854)	(13,842,060)	(15,226,266)	(16,610,472)	(16,610,472)
45	Prior Period True-up Balance - Over/(Under)	14,380,874	12,996,668	11,612,462	10,228,256	8,844,049	7,459,844	6,075,638	4,691,432	3,307,226	1,923,020	538,814	(845,392)	(845,392)
46	**Net Capacity True-up Over/(Under) (Line 42+45)**	8,464,830	2,125,894	(1,601,261)	(4,525,778)	(5,308,275)	(5,888,778)	(6,298,148)	(6,273,488)	819,203	6,642,789	6,179,600	1,848,509	1,848,509

[1] Approved in Commission Order No. PSC-2018-0532-PAA-EQ.
[2] Approved in Commission Order No. PSC-2018-0490-FOF-EI.

Docket No. 20200001-EI
Witness: Menendez
Exhibit No. (CAM-3T)
Schedule A1-1
Sheet 1 of 9
REVISED

DUKE ENERGY FLORIDA, LLC
FUEL AND PURCHASED POWER

DECEMBER 2019

		$				MWH				CENTS/KWH			
		ACTUAL	EST MATED	D FFERENCE AMOUNT	%	ACTUAL	EST MATED	D FFERENCE AMOUNT	%	ACTUAL	EST MATED	DIFFERENCE AMOUNT	%
1	FUEL COST OF SYSTEM NET GENERATION (SCH A3)	79,539,979	92,653,910	(13,113,931)	(14.2)	2,665,943	3,115,729	(449,785)	(14.4)	2.9836	2.9737	0.0099	0 3
2	COAL CAR SALE	0	0	0	0.0	0	0	0	0.0	0.0000	0.0000	0.0000	0 0
3	ADJUSTMENTS TO FUEL COST - MISCELLANEOUS	4,157,828	1,162,111	2,995,717	257.8	0	0	0	0.0	0.0000	0.0000	0.0000	0 0
4	TOTAL COST OF GENERATED POWER	83,697,806	93,816,021	(10,118,215)	(10.8)	2,665,943	3,115,729	(449,785)	(14.4)	3.1395	3.0110	0.1285	4 3
5	ENERGY COST OF PURCHASED POWER - FIRM (SCH A7)	3,380,078	1,106,770	2,273,308	205.4	78,567	28,174	50,393	178.9	4.3022	3.9283	0.3739	9 5
6	ENERGY COST OF SCH C,X ECONOMY PURCH - BROKER (SCH A9)	-	0	0	0.0	0	0	0	0.0	0.0000	0.0000	0.0000	0 0
7	ENERGY COST OF ECONOMY PURCH - NON-BROKER (SCH A9)	340,062	223,111	116,951	52.4	12,124	6,202	5,922	95.5	2.8049	3.5975	(0.7926)	(22 0)
8	PAYMENTS TO QUAL FYING FACILIT ES (SCH A8)	8,695,897	10,026,097	(1,330,200)	(13.3)	207,155	254,820	(47,665)	(18.7)	4.1978	3.9346	0.2632	6.7
9	TOTAL COST OF PURCHASED POWER	12,416,037	11,355,978	1,060,059	9.3	297,846	289,196	8,650	3.0	4.1686	3.9267	0.2419	6 2
10	TOTAL AVAILABLE MWH					2,963,789	3,404,924	(441,135)	(13.0)				
11	FUEL COST OF OTHER POWER SALES (SCH A6)	(61,580)	(214,445)	152,865	(71.3)	(3,995)	(8,274)	4,279	(51.7)	1.5414	2.5918	(1.0504)	(40 5)
11a	GA N ON OTHER POWER SALES - 100% (SCH A6)	(19,616)	(56,756)	37,140	(65.4)	(3,995)	(8,274)	4,279	(51.7)	0.4910	0.6860	(0.1950)	(28.4)
11b	GA N ON TOTAL POWER SALES - 20% (SCH A6)	3,923	11,351	(7,428)	(65.4)	0	0	0	0.0	0.0000	0.0000	0.0000	0 0
12	FUEL COST OF STRAT FIED SALES	(1,685,206)	(4,008,072)	2,322,865	(58.0)	(72,866)	(156,130)	83,264	(53.3)	2.3127	2.5671	(0.2544)	(9 9)
13	TOTAL FUEL COST AND GA NS ON POWER SALES	(1,762,479)	(4,267,921)	2,505,443	(58.7)	(76,861)	(164,404)	87,543	(53.3)	2.2931	2.5960	(0.3029)	(11.7)
14	NET INADVERTENT AND WHEELED NTERCHANGE					5,417	0	5,417					
15	TOTAL FUEL AND NET POWER TRANSACTIONS	94,351,364	100,904,077	(6,552,713)	(6.5)	2,892,345	3,240,520	(348,175)	(10.7)	3.2621	3.1138	0.1483	4 8
16	NET UNB LLED	455,982	4,116,937	(3,660,955)	(88.9)	(13,978)	(132,215)	118,237	(89.4)	0.0164	0.1423	(0.1259)	(88 5)
17	COMPANY USE	447,554	648,184	(200,630)	(31.0)	(13,720)	(20,816)	7,097	(34.1)	0.0161	0.0224	(0.0063)	(28.1)
18	T & D LOSSES	2,968,805	6,059,654	(3,090,849)	(51.0)	(91,009)	(194,605)	103,596	(53.2)	0.1070	0.2095	(0.1025)	(48 9)
19	ADJUSTED SYSTEM KWH SALES (SCH A2 PG 1 OF 2)	94,351,364	100,904,077	(6,552,713)	(6.5)	2,773,639	2,892,884	(119,245)	(4.1)	3.4017	3.4880	(0.0863)	(2 5)
20	WHOLESALE KWH SALES (EXCLUD NG STRAT F ED SALES)	(415,146)	(484,340)	69,194	(14.3)	(12,087)	(13,906)	1,819	(13.1)	3.4346	3.4829	(0.0483)	(1.4)
21	JURISDICTIONAL KWH SALES	93,936,218	100,419,738	(6,483,519)	(6.5)	2,761,551	2,878,978	(117,426)	(4.1)	3.4016	3.4880	(0.0864)	(2 5)
22	JURISDICTIONAL KWH SALES ADJUSTED FOR L NE LOSS - 1.00112	93,968,157	100,453,881	(6,485,724)	(6.5)	2,761,551	2,878,978	(117,426)	(4.1)	3.4027	3.4892	(0.0865)	(2 5)
23	PRIOR PERIOD TRUE-UP	12,370,910	12,370,910	(0)	0.0	2,761,551	2,878,978	(117,426)	(4.1)	0.4480	0.4297	0.0183	4 3
24	TOTAL JURISDICTIONAL FUEL COST	106,339,066	112,824,791	(6,485,724)	(5.8)	2,761,551	2,878,978	(117,426)	(4.1)	3.8507	3.9189	(0.0682)	(1.7)
25	REVENUE TAX FACTOR									1.00072	1.00072	0.0000	0 0
26	FUEL COST ADJUSTED FOR TAXES									3.8535	3.9217	(0.0682)	(1.7)
27	GP F	(191,794)	(191,792)			2,761,551	2,878,978			(0.0069)	(0.0067)	(0.0002)	3 0
28	TOTAL FUEL COST FACTOR ROUNDED TO THE NEAREST 001 CENTS/KWH									3.847	3 915	(0 068)	(1 8)

*Line 15a. MWH Data for Infomational Purposes Only

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20200001-EI EXHIBIT: 4
PARTY: DUKE ENERGY FLORIDA – DIRECT
DESCRIPTION: Christopher Menendez CAM-3T

DUKE ENERGY FLORIDA, LLC
FUEL AND PURCHASED POWER
COST RECOVERY CLAUSE CALCULATION
YEAR TO DATE - DECEMBER 2019

		$				MWH				CENTS/KWH			
		ACTUAL	EST MATED	D FFERENCE AMOUNT	%	ACTUAL	EST MATED	D FFERENCE AMOUNT	%	ACTUAL	EST MATED	DIFFERENCE AMOUNT	%
1	FUEL COST OF SYSTEM NET GENERATION (SCH A3)	1,230,882,664	1,228,035,464	2,847,200	0.2	39,746,616	40,089,304	(342,689)	(0.9)	3.0968	3.0632	0.0336	1.1
2	COAL CAR SALE	(178,380)	0	(178,380)	0.0	0	0	0	0.0	0.0000	0.0000	0.0000	0 0
3	ADJUSTMENTS TO FUEL COST - MISCELLANEOUS	20,106,418	14,343,516	5,762,902	40.2	0	0	0	0.0	0.0000	0.0000	0.0000	0 0
4	TOTAL COST OF GENERATED POWER	1,250,810,702	1,242,378,980	8,431,722	0.7	39,746,616	40,089,304	(342,689)	(0.9)	3.1470	3.0990	0.0480	1 6
5	ENERGY COST OF PURCHASED POWER - FIRM (SCH A7)	93,905,144	76,836,292	17,068,852	22.2	2,351,996	1,967,131	384,865	19.6	3.9926	3.9060	0.0866	2 2
6	ENERGY COST OF SCH C,X ECONOMY PURCH - BROKER (SCH A9)	0	0	0	0.0	0	0	0	0.0	0.0000	0.0000	0.0000	0 0
7	ENERGY COST OF ECONOMY PURCH - NON-BROKER (SCH A9)	5,914,484	2,923,082	2,991,402	102.3	144,528	74,548	69,981	93.9	4.0923	3.9211	0.1712	4.4
8	PAYMENTS TO QUAL FYING FACILIT ES (SCH A8)	99,477,111	110,423,752	(10,946,641)	(9.9)	2,487,579	2,724,789	(237,210)	(8.7)	3.9990	4.0526	(0.0536)	(1 3)
9	TOTAL COST OF PURCHASED POWER	199,296,739	190,183,126	9,113,613	4.8	4,984,104	4,766,468	217,636	4.6	3.9986	3.9900	0.0086	0 2
10	TOTAL AVAILABLE MWH					44,730,720	44,855,772	(125,052)	(0.3)				
11	FUEL COST OF OTHER POWER SALES (SCH A6)	(4,456,354)	(4,834,701)	378,347	(7.8)	(151,162)	(141,389)	(9,773)	6.9	2.9481	3.4194	(0.4713)	(13 8)
11a	GA N ON OTHER POWER SALES - 100% (SCH A6)	(1,649,135)	(1,656,431)	7,296	(0.4)	(151,162)	(141,389)	(9,773)	6.9	1.0910	1.1715	(0.0805)	(6 9)
11b	GA N ON TOTAL POWER SALES - 20% (SCH A6)	78,518	64,544	13,973	21.7	0	0	0	0.0	0.0000	0.0000	0.0000	0 0
12	FUEL COST OF STRAT FIED SALES	(55,795,180)	(54,653,263)	(1,141,918)	2.1	(2,680,833)	(2,453,803)	(227,030)	9.3	2.0813	2.2273	(0.1460)	(6 6)
13	TOTAL FUEL COST AND GA NS ON POWER SALES	(61,822,152)	(61,079,851)	(742,302)	1.2	(2,831,995)	(2,595,192)	(236,803)	9.1	2.1830	2.3536	(0.1706)	(7 3)
14	NET INADVERTENT AND WHEELED NTERCHANGE					229,627	107,645	121,982					
15	TOTAL FUEL AND NET POWER TRANSACTIONS	1,388,285,289	1,371,482,256	16,803,034	1.2	42,128,352	42,368,225	(239,873)	(0.6)	3.2954	3.2371	0.0583	1 8
16	NET UNB LLED	(4,877,144)	(4,781,443)	(95,701)	2.0	84,047	161,728	(77,681)	(48.0)	(0.0124)	(0.0121)	(0.0003)	2 5
17	COMPANY USE	4,994,891	6,508,234	(1,513,343)	(23.3)	(148,493)	(199,795)	51,302	(25.7)	0.0127	0.0165	(0.0038)	(23 0)
18	T & D LOSSES	87,225,368	90,729,998	(3,504,630)	(3.9)	(2,638,561)	(2,773,127)	134,566	(4.9)	0.2212	0.2294	(0.0082)	(3 6)
19	ADJUSTED SYSTEM KWH SALES (SCH A2 PG 1 OF 2)	1,388,285,289	1,371,482,256	16,803,034	1.2	39,425,345	39,557,031	(131,686)	(0.3)	3.5213	3.4671	0.0542	1 6
20	WHOLESALE KWH SALES (EXCLUD NG STRAT F ED SALES)	(8,398,720)	(8,459,368)	60,647	(0.7)	(238,000)	(243,064)	5,063	(2.1)	3.5289	3.4803	0.0486	1.4
21	JURISDICTIONAL KWH SALES	1,379,886,569	1,363,022,888	16,863,681	1.2	39,187,344	39,313,967	(126,623)	(0.3)	3.5213	3.4670	0.0543	1 6
22	JURISDICTIONAL KWH SALES ADJUSTED FOR L NE LOSS - 1.00112	1,380,352,068	1,363,482,653	16,869,415	1.2	39,187,344	39,313,967	(126,623)	(0.3)	3.5224	3.4682	0.0542	1 6
23	PRIOR PERIOD TRUE-UP	148,450,915	148,450,920	(5)	0.0	39,187,344	39,313,967	(126,623)	(0.3)	0.3788	0.3776	0.0012	0 3
24	TOTAL JURISDICTIONAL FUEL COST	1,528,802,983	1,511,933,573	16,869,410	1.1	39,187,344	39,313,967	(126,623)	(0.3)	3.9012	3.8458	0.0554	1.4
25	REVENUE TAX FACTOR									1.00072	1.00072	0.0000	0 0
26	FUEL COST ADJUSTED FOR TAXES									3.9040	3.8486	0.0554	1.4
27	GP F	(2,301,526)	(2,301,526)			39,187,344	39,313,967			(0.0059)	(0.0059)	0.0000	100 0
28	TOTAL FUEL COST FACTOR ROUNDED TO THE NEAREST 001 CENTS/KWH									3.898	3 843	0 055	1.4

*Line 15a. MWH Data for Infomational Purposes Only

DUKE ENERGY FLOR DA, LLC
CALCULATION OF TRUE-UP AND INTEREST PROVISION
DECEMBER 2019

		CURRENT MONTH				YEAR TO DATE			
		ACTUAL	EST MATED	D FFERENCE	PERCENT	ACTUAL	EST MATED	D FFERENCE	PERCENT
A .	FUEL COSTS AND NET POWER TRANSACTIONS								
1 .	FUEL COST OF SYSTEM NET GENERATION	$79,539,979	92,653,910	($13,113,931)	(14.2)	$1,230,882,664	$1,228,035,464	$2,847,200	0.2
1a.	COAL CAR SALE	-	0	0	0.0	(178,380)	0	(178,380)	0.0
2 .	FUEL COST OF POWER SOLD	(61,580)	(214,445)	152,865	(71.3)	(4,456,354)	(4,834,701)	378,347	(7.8)
2a.	GA N ON POWER SALES	(15,693)	(45,405)	29,712	(65.4)	(1,570,617)	(1,591,887)	21,270	(1.3)
3 .	FUEL COST OF PURCHASED POWER	3,380,078	1,106,770	2,273,308	205.4	93,905,144	76,836,292	17,068,852	22.2
3a.	ENERGY PAYMENTS TO QUAL FY NG FACILIT ES	8,695,897	10,026,097	(1,330,200)	(13.3)	99,477,111	110,423,752	(10,946,641)	(9.9)
4 .	ENERGY COST OF ECONOMY PURCHASES	340,062	223,111	116,951	52.4	5,914,484	2,923,082	2,991,402	102.3
5 .	TOTAL FUEL & NET POWER TRANSACTIONS	91,878,743	103,750,038	(11,871,295)	(11.4)	1,423,974,051	1,411,792,002	12,182,049	0.9
6 .	ADJUSTMENTS TO FUEL COST:								
6a.	FUEL COST OF STRAT FIED SALES	(1,685,206)	(4,008,072)	2,322,865	(58 0)	(55,795,180)	(54,653,263)	(1,141,918)	2.1
6b.	OTHER- JURISDICTIONAL ADJUSTMENTS (see detail below)	4,157,828	1,162,111	2,995,717	257 8	20,106,418	14,343,516	5,762,902	40.2
6c.	OTHER - PRIOR PERIOD ADJUSTMENT	0	0	0	0 0	0	0	0	0.0
7 .	ADJUSTED TOTAL FUEL & NET PWR TRNS	$94,351,364	$100,904,077	($6,552,713)	(6.5)	$1,388,285,289	$1,371,482,256	$16,803,034	1.2

FOOTNOTE: DETAIL OF LINE 6b ABOVE

INSPECTION & FUEL ANALYSIS REPORTS {Wholesale Portion}	$0	$0	$0	$0	$0	$0
CITRUS CC INEFFICIENT USE	0	0	0	0	0	0
UNIVERSITY OF FLORIDA STEAM REVENUE ALLOCATION {Wholesale Portion}	440	0	440	7,150	0	7,150
FPD AGREEMENT TERMINATION	0	0	0	0	0	0
TANK BOTTOM ADJUSTMENT	0	0	0	0	0	0
AERIAL SURVEY ADJUSTMENT (Coal Pile)	3,057,408	0	3,057,408	5,821,944	0	5,821,944
FDP AGREEMENT TERMINATION	1,099,979	0	1,099,979	14,186,731	0	14,186,731
RAIL CAR SALE PROCEEDS	0	0	0	0	0	0
Gain/Loss on Disposition of Oil	0	0	0	0	0	0
NET METER SETTLEMENT	0	0	0	90,593	0	90,593
N/A - Not used	0	0	0	0	0	0
Derivative Collateral Interest	0	0	0	0	0	0
SUBTOTAL L NE 6b SHOWN ABOVE	$4,157,828	$0	$4,157,828	$20,106,418	$0	$20,106,418

B.	KWH SALES								
1 .	JURISDICTIONAL SALES	2,761,550,962	2,878,977,695	(117,426,733)	(4.1)	39,187,342,961	39,313,967,025	(126,624,064)	(0.3)
2 .	NON JURISDICTIONAL (WHOLESALE) SALES	12,087,090	13,906,069	(1,818,979)	(13.1)	238,000,092	243,063,578	(5,063,486)	(2.1)
3 .	TOTAL SALES	2,773,638,052	2,892,883,764	(119,245,712)	(4.1)	39,425,343,053	39,557,030,603	(131,687,550)	(0.3)
4 .	JURISDICTIONAL SALES % OF TOTAL SALES	99.56	99 52	0.04	0.0	99.40	99.39	0.01	0.0

Docket No.	20200001-EI
Witness:	Menendez
Exhibit No.	(CAM-3T)
Schedule	A2-2
	Sheet 4 of 9

DUKE ENERGY FLOR DA, LLC
CALCULATION OF TRUE-UP AND INTEREST PROVISION
DECEMBER 2019

		CURRENT MONTH				YEAR TO DATE			
		ACTUAL	EST MATED	D FFERENCE	PERCENT	ACTUAL	EST MATED	D FFERENCE	PERCENT
C.	TRUE UP CALCULATION								
1 .	JURISDICTIONAL FUEL REVENUE	$105,460,463	$114,184,412	($8,723,949)	(7.6)	$1,548,367,879	$1,553,120,468	($4,752,589)	(0.3)
2 .	ADJUSTMENTS:	0	0	0	0.0	0	0	0	0.0
2a.	TRUE UP PROVISION	(12,370,910)	(12,370,910)	0	0.0	(148,450,915)	(148,450,920)	5	0.0
2b.	NCENTIVE PROVISION	191,794	191,792	2	0 0	2,301,526	2,301,526	(0)	0.0
3 .	TOTAL JURISDICTIONAL FUEL REVENUE	93,281,347	102,005,294	(8,723,947)	(8 6)	1,402,218,490	1,406,971,074	(4,752,584)	(0.3)
4 .	ADJ TOTAL FUEL & NET PWR TRNS (L NE A7)	94,351,364	100,904,077	(6,552,713)	(6 5)	1,388,285,289	1,371,482,256	16,803,034	1.2
5 .	JURISDICTIONAL SALES % OF TOT SALES (L NE B4)	99.56	99 52	0.04	0 0	99.40	99.39	0.01	0.0
6 .	JURISDICTIONAL FUEL & NET POWER TRANSACTIONS (L NE C4 * L NE C5 * 1 00112 LOSS MULT PLIER)	93,968,157	100,453,881	(6,485,724)	(6 5)	1,380,352,068	1,363,482,653	16,869,415	1.2
7 .	TRUE UP PROVISION FOR THE MONTH OVER/(UNDER) COLLECTION (LINE C3 - C6)	(686,810)	1,551,413	(2,238,223)	(144 3)	21,866,422	43,488,421	(21,621,999)	(49.7)
8 .	NTEREST PROVISION FOR THE MONTH (L NE D10)	(58,911)	(41,829)	(17,082)	40 8	(3,435,661)	(3,522,429)	86,768	(2.5)
9 .	TRUE UP & NTEREST PROVISION BEG OF MONTH/PERIOD	(47,623,102)	(28,343,173)	(19,279,929)	68 0	(202,879,590)	(202,879,590)	0	0.0
10.	TRUE UP COLLECTED (REFUNDED)	12,370,910	12,370,910	(0)	0 0	148,450,915	148,450,920	(5)	0.0
11.	END OF PERIOD TOTAL NET TRUE UP (LINES C7 + C8 + C9 + C10)	(35,997,914)	(14,462,679)	(21,535,235)	148 9	(35,997,914)	(14,462,679)	(21,535,235)	148.9
12.	OTHER:	0				0		0	
13.	END OF PERIOD TOTAL NET TRUE UP (L NES C11 + C12)	($35,997,914)	(14,462,679)	(21,535,235)	148.9	($35,997,914)	(14,462,679)	(21,535,235)	148.9

D.	NTEREST PROVISION				
1 .	BEGINN NG TRUE UP (L NE C9)	($182,171,211)	N/A	--	--
2 .	ENDING TRUE UP (LINES C7 + C9 + C10 + C12)	(202,500,688)	N/A	--	--
3 .	TOTAL OF BEG NNING & END NG TRUE UP	(384,671,899)	N/A	--	--
4 .	AVERAGE TRUE UP (50% OF L NE D3)	(192,335,949)	N/A	--	--
5 .	INTEREST RATE - FIRST DAY OF REPORTING MONTH	2.300	N/A	--	--
6 .	INTEREST RATE - FIRST DAY OF SUBSEQUENT MONTH	2.420	N/A	--	--
7 .	TOTAL (L NE D5 + LINE D6)	4.720	N/A		
8 .	AVERAGE NTEREST RATE (50% OF L NE D7)	2.360	N/A	--	--
9 .	MONTHLY AVERAGE INTEREST RATE (LINE D8/12)	0.197	N/A	--	--
10.	INTEREST PROVISION (LINE D4 * L NE D9)	($378,902)	N/A	--	--

N O T

A-3 Generating System Comparative Data Report

Duke Energy Florida, LLC

Docket No. 20200001-EI
Witness: Menendez
Exhibit No. (CAM-3T)
Schedule: A3-1
Sheet 5 of 9
REVISED

FUEL COST OF SYSTEM	ACTUAL	ESTIMATED	DIFFERENCE	DIFFERENCE (%)
NET GENERATION ($)				
1 - HEAVY OIL	0	0	0	0.0 %
2 - LIGHT OIL	14,226,223	6,406,086	7,820,137	122.1 %
3 - COAL	161,620,864	148,303,407	13,317,457	9.0 %
4 - GAS	1,055,035,576	1,073,325,970	(18,290,394)	(1.7 %)
5 - NUCLEAR	0	0	0	0.0 %
6				
7				
8 - TOTAL ($)	1,230,882,664	1,228,035,463	2,847,201	0.2 %
SYSTEM NET GENERATION (MWH)				
9 - HEAVY OIL	0	0	0	0.0 %
10 - LIGHT OIL	33,046	18,782	14,264	75.9 %
11 - COAL	4,321,614	3,610,045	711,569	19.7 %
12 - GAS	35,169,835	36,234,383	(1,064,548)	(2.9 %)
13 - NUCLEAR	0	0	0	0.0 %
14 - SOLAR	222,124	226,096	(3,972)	(1.8 %)
15				
16 - TOTAL (MWH)	39,746,619	40,089,306	(342,687)	(0.9 %)
UNITS OF FUEL BURNED				
17 - HEAVY OIL (BBL)	0	0	0	0.0 %
18 - LIGHT OIL (BBL)	121,326	51,716	69,610	136.7 %
19 - COAL (TON)	1,976,271	1,666,570	309,701	18.6 %
20 - GAS (MCF)	262,546,275	266,088,201	(3,541,926)	(1.3 %)
21 - NUCLEAR (MMBTU)	0	0	0	0.0 %
22				
23				
BTUS BURNED (MILLION BTU)				
24 - HEAVY OIL	0	0	0	0.0 %
25 - LIGHT OIL	698,679	297,830	400,849	134.6 %
26 - COAL	44,098,849	38,166,941	5,931,908	15.5 %
27 - GAS	268,325,594	268,575,668	(250,074)	(0.1 %)
28 - NUCLEAR	0	0	0	0.0 %
29				
30				
31 - TOTAL (MILLION BTU)	313,123,122	307,040,439	6,082,683	2.0 %

A-3 Generating System Comparative Data Report

Duke Energy Florida, LLC

Docket No. 20200001-EI
Witness: Menendez
Exhibit No. (CAM-3T)
Schedule: A3-1
Sheet 6 of 9
REVISED

FUEL COST OF SYSTEM	ACTUAL	ESTIMATED	DIFFERENCE	DIFFERENCE (%)
GENERATION MIX (% MWH)				
32 - HEAVY OIL	0.0	0.00	0.0	0.0 %
33 - LIGHT OIL	0.1	0.05	0.0	77.5 %
34 - COAL	10.9	9.01	1.9	20.7 %
35 - GAS	88.5	90.38	(1.9)	(2.1 %)
36 - NUCLEAR	0.0	0.00	0.0	0.0 %
37 - SOLAR	0 56	0.56	(0.01)	(0.9 %)
38				
39 - TOTAL (% MWH)	100.0	100.0	0.0	0.0 %
FUEL COST PER UNIT ($)				
40 - HEAVY OIL ($/BBL)	0 00	0.00	0.00	0.0 %
41 - LIGHT OIL ($/BBL)	117 26	123.87	(6.60)	(5.3 %)
42 - COAL ($/TON)	81.78	88.99	(7.21)	(8.1 %)
43 - GAS ($/MCF)	4 02	4.03	(0.02)	(0.4 %)
44 - NUCLEAR ($/MBTU)	0 00	0.00	0.00	0.0 %
45				
46				
FUEL COST PER MILLION BTU ($/MILLION BTU)				
47 - HEAVY OIL	0 00	0.00	0.00	0.0 %
48 - LIGHT OIL	20 36	21.51	(1.15)	(5.3 %)
49 - COAL	3.66	3.89	(0.22)	(5.7 %)
50 - GAS	3 93	4.00	(0.06)	(1.6 %)
51 - NUCLEAR	0 00	0.00	0.00	0.0 %
52				
53				
54 - SYSTEM ($/MBTU)	3 93	4.00	(0.07)	(1.7 %)
BTU BURNED PER KWH (BTU/KWH)				
55 - HEAVY OIL		0	0	0.0 %
56 - LIGHT OIL	21,143	15,857	5,285	33.3 %
57 - COAL	10,204	10,572	(368)	(3.5 %)
58 - GAS	7,629	7,412	217	2.9 %
59 - NUCLEAR	0	0	0	0.0 %
60				
61				
62 - SYSTEM (BTU/KWH)	7,878	7,659	219	2.9 %

A-3 Generating System Comparative Data Report

Duke Energy Florida, LLC

Docket No. 20200001-EI
Witness: Menendez
Exhibit No. (CAM-3T)
Schedule: A3-1
Sheet 7 of 9
REVISED

FUEL COST OF SYSTEM	ACTUAL	ESTIMATED	DIFFERENCE	DIFFERENCE (%)
GENERATED FUEL COST PER KWH (CENTS/KWH)				
63 - HEAVY OIL	0 00	0.00	0.00	0.0 %
64 - LIGHT OIL	43 05	34.11	8.94	26.2 %
65 - COAL	3.74	4.11	(0.37)	(9.0 %)
66 - GAS	3 00	2.96	0.04	1.3 %
67 - NUCLEAR	0 00	0.00	0.00	0.0 %
68				
69				
70 - SYSTEM (CENTS/KWH)	3.10	3.06	0.03	1.1 %

Duke Energy Florida, LLC
Schedule A6
Power Sold for the Month of
December 2019

Docket No. 20200001-EI
Witness: Menendez
Exhibit No. (CAM-3T)
Schedule A6
Sheet 8 of 9

(1) Sold To	(2) Type & Schedule	(3) Total KWH Sold (000)	(4) KWH Wheeled from Other Systems (000)	(5) KWH from Own Generation (000)	(6a) Fuel Cost C/KWH	(6b) Total Cost C/KWH	(7) Fuel Adj Total $	(8) Total Cost $	(9) Gain on Sales $
ESTIMATED		8,274		8,274	2.592	3.278	214,445.00	271,201.00	56,756.00
ACTUAL									
Reedy Creek Improvement District	CR-1	3,820		3,820	1.443	1.997	55,140.55	76,284.90	21,144.35
Tampa Electric Company	CR-1	100		100	4.899	3.213	4,898.50	3,213.21	(1,685.29)
The Energy Authority	Schedule OS	75		75	2.054	2.449	1,540.50	1,836.75	296.25
ADJUSTMENTS									
PJM Settlements								(139.15)	(139.15)
Subtotal - Gain on Other Power Sales		3,995		3,995	1.541	2.032	61,579.55	81,195.71	19,616.16
CURRENT MONTH TOTAL		3,995		3,995	1.541	2.032	61,579.55	81,195.71	19,616.16
DIFFERENCE		(4,279)		(4,279)	(1.050)	(1.245)	(152,865.45)	(190,005.29)	(37,139.84)
DIFFERENCE %		(52)		(52)	(40.527)	(37.993)	(71.28)	(70.06)	(65.44)
CUMULATIVE ACTUAL		151,162		151,162	2.948	4.039	4,456,354.48	6,105,488.42	1,649,134.86
CUMULATIVE ESTIMATED		141,388		141,388	3.419	4.591	4,834,701.00	6,491,132.00	1,656,431.00
DIFFERENCE		9,774		9,774	(0.471)	(0.552)	(378,346.52)	(385,643.58)	(7,296.14)
DIFFERENCE %		7		7	(13.785)	(12.023)	(7.83)	(5.94)	(0.44)

Duke Energy Florida, LLC
Schedule A12 - Capacity Costs
For the Period January - December 2019

Docket No. 20180001-EI
Witness: Menendez
Exhibit No. (CAM-3T)
Schedule A12

	Counterparty	Type	MW	Start Date - End Date	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	YTD
1	Orange Cogen (ORANGECO)	QF	74.00	7/1/95 - 12/31/24	5,600,934	5,600,934	5,600,934	5,600,934	5,600,934	5,600,934	5,600,934	5,600,934	5,600,934	5,600,934	5,516,015	5,600,934	67,126,287
2	Orlando Cogen Limited (ORLACOGL)	QF	79.20	9/1/93 - 12/31/23	5,636,162	5,636,162	5,636,162	5,636,162	5,636,162	5,636,162	5,636,162	5,636,162	5,636,162	5,636,162	5,636,162	5,636,162	67,633,943
3	Pasco County Resource Recovery (PASCOUNT)	QF	23.00	1/1/95 - 12/31/24	2,019,170	2,019,170	2,019,170	2,019,170	2,019,170	2,019,170	2,019,170	2,019,170	2,019,170	2,019,170	2,019,170	2,019,170	24,230,040
4	Pinellas County Resource Recovery (PINCOUNT)	QF	54.75	1/1/95 - 12/31/24	4,806,503	4,806,503	4,806,503	4,806,503	4,806,503	4,806,503	4,806,503	4,806,503	4,806,503	4,806,503	4,806,503	4,806,503	57,678,030
5	Polk Power Partners, L.P. (MULBERRY)	QF	115.00	8/1/94 - 8/8/24	7,693,916	7,693,916	7,693,916	7,693,916	7,693,916	7,693,916	7,693,916	7,693,916	7,693,916	7,693,916	7,693,916	7,693,916	92,326,988
6	Wheelabrator Ridge Energy, Inc. (RIDGEGEN)	QF	39.60	8/1/94 - 12/31/23	800,946	0	0	0	0	0	0	0	0	0	0	0	800,946
7	Southern purchase - Franklin	Other	425	6/1/16 - 5/31/21	4,611,942	4,802,362	2,752,978	2,755,639	2,814,130	5,254,911	6,502,231	6,128,473	4,721,360	2,755,745	2,747,786	3,583,491	49,431,048
8	Retail Wheeling				(45,534)	(8,443)	(35,373)	(39,200)	(57,327)	(29,146)	(30,224)	(2,595)	(14,622)	(443)	(33,247)	(963)	(297,116)
9	CR-3 Projected Expense				3,775,626	3,753,198	3,730,770	3,708,343	3,685,916	3,663,488	3,641,061	3,618,633	3,596,207	3,573,779	3,551,352	3,483,417	43,781,791
10	ISFSI Return				573,320	573,320	573,320	573,320	573,320	573,320	573,320	573,320	573,320	573,320	573,320	573,320	6,879,837
11	Vandolah Capacity Purchase			June 2012 - May 2027	2,919,279	2,891,051	1,947,614	1,942,582	2,793,653	5,773,604	5,928,134	5,787,984	2,747,117	1,940,621	2,042,583	2,984,299	39,698,523
12	Schedule H Capacity Sales - Tallahassee	1	-1	on-going no term date	(48,411)	0	(64,548)	0	0	(114,031)	6,705	0	131,000	0	384,713	201,135	496,563
13	Shady Hills Tolling	1	517	4/1/07-4/30/24	1,976,940	1,976,940	1,412,100	1,366,200	1,912,680	3,888,000	3,888,000	3,888,000	(2,073,600)	1,366,200	1,351,582	1,973,160	22,926,202
14	RidgeGen Agreement Termination				0	750,770	747,221	743,672	740,123	736,573	730,453	726,952	723,451	719,950	716,449	696,212	8,031,827
15	Hamilton SoBRA True-Up				0	0	0	0	0	0	0	0	(478,334)	0	0	0	(478,334)
	TOTAL				40,320,791	40,495,882	36,820,766	36,807,240	38,219,179	45,503,404	46,996,364	46,477,452	35,682,583	36,685,856	37,006,302	39,250,756	480,266,574

Duke Energy Florida, LLC
Capital Structure and Cost Rates Applied to Capital Projects
Estimated for the Period of : January 2019 through June 2019

	Adjusted Retail $000's	Ratio	Cost Rate	Weighted Cost	Pre-Tax Weighted Cost Rate
Common Equity	$ 4,374,787	40.92%	10.50%	4.30%	5.69%
Long Term Debt	4,497,052	42.06%	4.90%	2.06%	2.06%
Short Term Debt	(193,058)	-1.81%	0.88%	-0.02%	-0.02%
Customer Deposits - Active	179,649	1.68%	2.35%	0.04%	0.04%
Customer Deposits - Inactive	1,597	0.01%	0.00%	0.00%	0.00%
Deferred Tax	1,826,909	17.09%	0.00%	0.00%	0.00%
Deferred Tax (FAS 109)	0	0.00%	0.00%	0.00%	0.00%
ITC	5,239	0.05%	7.85%	0.00%	0.00%
	$ 10,692,175	100.00%		6.38%	7.78%

Total Debt	2.09%	2.09%
Total Equity	4.30%	5.69%

Above is the May 2018 DEF Surveillance Report capital structure and cost rates. See Stipulation & Settlement Agreement in Order No. PSC-12-0425-PSS-EU, Docket No. 120007-EI.

The Pre-Tax Weighted Cost Rate reflects the updated Florida State Corporate Tax Rate.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20200001-EI EXHIBIT: 5
PARTY: DUKE ENERGY FLORIDA – DIRECT
DESCRIPTION: Christopher Menendez CAM-4T

Duke Energy Florida, LLC
Capital Structure and Cost Rates Applied to Capital Projects
Estimated for the Period of : July 2019 through December 2019

	Adjusted Retail $000's	Ratio	Cost Rate	Weighted Cost	Pre-Tax Weighted Cost Rate
Common Equity	$ 4,874,577	41.01%	10.50%	4.31%	5.71%
Long Term Debt	4,845,025	40.77%	4.70%	1.92%	1.92%
Short Term Debt	(59,427)	-0.50%	-0.36%	0.00%	0.00%
Customer Deposits - Active	176,757	1.49%	2.38%	0.04%	0.04%
Customer Deposits - Inactive	1,853	0.02%	0.00%	0.00%	0.00%
Deferred Tax	2,026,313	17.05%	0.00%	0.00%	0.00%
Deferred Tax (FAS 109)	0	0.00%	0.00%	0.00%	0.00%
ITC	19,806	0.17%	7.71%	0.01%	0.01%
	$ 11,884,905	100.00%		6.27%	7.67%
			Total Debt	1.97%	1.97%
			Total Equity	4.31%	5.71%

Above is the May 2019 DEF Surveillance Report capital structure and cost rates. See Stipulation & Settlement Agreement in Order No. PSC-12-0425-PSS-EU, Docket No. 120007-EI.

The Pre-Tax Weighted Cost Rate reflects the updated Florida State Corporate Tax Rate.

Docket No. 20200001-EI
Exhibit No. ____(CAM-2)
Part 1

Duke Energy Florida, LLC

Fuel Cost Recovery

Actual / Estimated True-Up

January through December 2020

Schedule E1-B – Calculation of Estimated True-up

Schedule E2 – Fuel Cost Recovery Clause Calculation by Month

Schedule E3 – Generating System Comparative Data

Schedule E4 – System Net Generation & Fuel Cost by Month

Schedule E5 – Inventory Analysis

Schedule E6 – Fuel Cost of Power Sold

Schedule E7 – Purchased Power

Schedule E8 – Energy Payments to Qualifying Facilities

Schedule E9 – Economy Energy Purchases

Capital Structure and Cost Rates Applied to Capital Projects
(Order No. PSC-12-0425-PAA-EU)

Docket No. 001-EI
Schedule E1-B
Exhibit CAM-2, Part 1

REVISED

Duke Energy Florida, LLC
Calculation of Estimated True-Up
6 Months Actual and 6 Months Estimated
January 2020 - December 2020

			Jan Actual	Feb Actual	Mar Actual	Apr Actual	May Actual	Jun Actual	6 Month Sub-Total
A	1	Fuel Cost of System Generation	$ 74,992,301	$ 65,717,824	$ 73,293,028	$ 70,415,016	$ 87,128,507	$ 89,708,430	$ 461,255,106
	2	Fuel Cost of Power Sold	(1,105,818)	(1,159,871)	(1,312,152)	(2,612,318)	(5,495,100)	(6,606,107)	(18,291,367)
	3	Fuel Cost of Purchased Power	1,777,132	3,137,635	6,173,029	1,917,858	6,444,417	9,797,876	29,247,948
	3a	Demand and Non-Fuel Cost of Purchased Power							-
	3b	Energy Payments to Qualified Facilities	7,319,413	7,093,012	5,551,577	5,410,902	7,518,681	7,427,850	40,321,435
	4	Energy Cost of Economy Purchases	143,759	406,521	1,053,448	485,384	407,645	188,921	2,685,678
	5	Adjustments to Fuel Cost	(12,011,163)	1,119,402	1,152,738	1,147,328	1,142,435	1,139,918	(6,309,342)
	6	TOTAL FUEL & NET POWER TRANSACTIONS (Sum of Lines A1 Through A5)	71,115,625	76,314,523	85,911,668	76,764,171	97,146,585	101,656,887	508,909,459
B	1	Jurisdictional mWh Sales	2,640,090	2,661,152	2,818,044	3,239,130	2,981,766	3,450,388	17,790,571
	2	Non-Jurisdictional mWh Sales	14,426	18,358	26,409	25,344	19,970	25,961	130,469
	3	TOTAL SALES (Lines B1 + B2)	2,654,517	2,679,511	2,844,453	3,264,474	3,001,736	3,476,349	17,921,039
	4	Jurisdictional % of Total Sales (Line B1/B3)	99.46%	99.31%	99.07%	99.22%	99.33%	99.25%	99.27%
C	1	Jurisdictional Fuel Recovery Revenue (Net of Revenue Taxes)	85,968,564	86,669,575	91,874,742	103,746,698	25,329,422	115,589,082	509,178,083
	2	True-Up Provision	(1,205,224)	(1,205,224)	(1,205,224)	(1,205,224)	77,026,561	(1,205,224)	71,000,441
	2a	Incentive Provision	(215,975)	(215,975)	(215,975)	(215,975)	(215,975)	(215,975)	(1,295,850)
	3	FUEL REVENUE APPLICABLE TO PERIOD (Sum of Lines C1 Through C2a)	84,547,365	85,248,376	90,453,543	102,325,499	102,140,008	114,167,883	578,882,674
	4	Fuel & Net Power Transactions (Line A6)	71,115,625	76,314,523	85,911,668	76,764,171	97,146,585	101,656,887	508,909,459
	5	Jurisdictional Total Fuel Costs & Net Power Transactions (Line A6 * Line B4 * Line Loss Multiplier)	70,755,650	75,811,447	85,139,074	76,189,021	96,525,617	100,925,738	505,346,546
	6	Over/(Under) Recovery (Line C3 - Line C5)	13,791,715	9,436,929	5,314,469	26,136,477	5,614,392	13,242,145	73,536,127
	7	Interest Provision	(38,474)	(20,905)	(11,239)	9,273	(736)	(3,260)	(65,341)
	8	TOTAL ESTIMATED TRUE-UP FOR THE PERIOD	13,753,241	9,416,023	5,303,230	26,145,750	5,613,656	13,238,886	73,470,786
	9	Plus: Prior Period Balance	(35,997,914)	(35,997,914)	(35,997,914)	(35,997,914)	(35,997,914)	(35,997,914)	(35,997,914)
	10	Plus: Cumulative True-Up Provision	1,205,224	2,410,448	3,615,672	4,820,896	(72,205,665)	(71,000,441)	(71,000,441)
	11	Subtotal Prior Period True-up	(34,792,690)	(33,587,466)	(32,382,242)	(31,177,018)	(108,203,579)	(106,998,355)	(106,998,355)
	12	Regulatory Accounting Adjustment	-	-	-	-	-	-	-
	13	TOTAL TRUE-UP BALANCE	($21,039,449)	(10,418,201)	($3,909,747)	$23,441,227	($47,971,678)	($33,527,567)	(33,527,567)

REVISED

Duke Energy Florida, LLC
Calculation of Estimated True-Up
6 Months Actual and 6 Months Estimated
January 2020 - December 2020

			Jul Estimated	Aug Estimated	Sep Estimated	Oct Estimated	Nov Estimated	Dec Estimated	12 Month Period
A	1	Fuel Cost of System Generation	$ 91,270,574	$ 102,001,873	$ 96,405,019	$ 90,833,949	$ 85,974,737	$ 97,148,448	$ 1,024,889,706
	2	Fuel Cost of Power Sold	(7,409,067)	(8,021,690)	(7,971,710)	(7,577,999)	(2,497,439)	(2,446,122)	(54,215,393)
	3	Fuel Cost of Purchased Power	8,533,384	4,575,768	3,696,906	4,358,593	1,085,538	174,484	51,672,621
	3a	Demand and Non-Fuel Cost of Purchased Power							0
	3b	Energy Payments to Qualified Facilities	8,407,595	8,411,122	7,949,571	7,091,011	8,225,712	9,032,312	89,438,758
	4	Energy Cost of Economy Purchases	177,886	113,649	178,038	128,590	91,292	125,383	3,500,516
	5	Adjustments to Fuel Cost	1,136,872	1,651,425	1,124,387	1,120,886	1,117,160	1,113,548	954,935
	6	TOTAL FUEL & NET POWER TRANSACTIONS (Sum of Lines A1 Through A5)	102,117,245	108,732,147	101,382,212	95,955,030	93,997,000	105,148,053	1,116,241,144
B	1	Jurisdictional mWh Sales	3,923,462	3,994,662	3,898,898	3,525,887	2,811,544	2,776,042	38,721,066
	2	Non-Jurisdictional mWh Sales	36,956	37,435	17,800	16,080	12,182	11,792	262,713
	3	TOTAL SALES (Lines B1 + B2)	3,960,418	4,032,097	3,916,698	3,541,967	2,823,725	2,787,834	38,983,778
	4	Jurisdictional % of Total Sales (Line B1/B3)	99.07%	99.07%	99.55%	99.55%	99.57%	99.58%	99.33%
C	1	Jurisdictional Fuel Recovery Revenue (Net of Revenue Taxes)	131,162,478	133,542,731	130,341,300	117,871,449	93,990,725	92,803,906	1,208,890,671
	2	True-Up Provision	(1,205,224)	(1,205,224)	(1,205,224)	(1,205,224)	(1,205,224)	(1,205,224)	63,769,102
	2a	Incentive Provision	(215,975)	(215,975)	(215,975)	(215,975)	(215,975)	(215,972)	(2,591,697)
	3	FUEL REVENUE APPLICABLE TO PERIOD (Sum of Lines C1 Through C2a)	129,741,279	132,121,532	128,920,101	116,450,250	92,569,526	91,382,710	1,270,068,076
	4	Fuel & Net Power Transactions (Line A6)	102,117,245	108,732,147	101,382,212	95,955,030	93,997,000	105,148,053	1,116,241,144
	5	Jurisdictional Total Fuel Costs & Net Power Transactions (Line A6 * Line B4 * Line Loss Multiplier)	101,198,916	107,754,331	100,957,279	95,552,845	93,621,826	104,738,890	1,109,170,633
	6	Over/(Under) Recovery (Line C3 - Line C5)	28,542,363	24,367,201	27,962,822	20,897,406	(1,052,301)	(13,356,180)	160,897,438
	7	Interest Provision	(1,489)	724	2,914	4,965	5,854	5,375	(46,998)
	8	TOTAL ESTIMATED TRUE-UP FOR THE PERIOD	28,540,875	24,367,925	27,965,736	20,902,370	(1,046,446)	(13,350,805)	160,850,440
	9	Plus: Prior Period Balance	(35,997,914)	(35,997,914)	(35,997,914)	(35,997,914)	(35,997,914)	(35,997,914)	(35,997,914)
	10	Plus: Cumulative True-Up Provision	(69,795,217)	(68,589,993)	(67,384,769)	(66,179,545)	(64,974,321)	(63,769,101)	(63,769,101)
	11	Subtotal Prior Period True-up	(105,793,131)	(104,587,907)	(103,382,683)	(102,177,459)	(100,972,235)	(99,767,015)	(99,767,015)
	12	Regulatory Accounting Adjustment	-	-	-	-	-	-	-
	13	TOTAL TRUE-UP BALANCE	($3,781,471)	$21,791,678	$50,962,638	$73,070,232	$73,229,010	$61,083,424	61,083,424

Docket No. 20200001-EI
Exhibit CAM-2, Part 1
Schedule E1-B-1
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Duke Energy Florida, LLC
Comparison of Actual/Estimated vs. Midcourse Projections
of the Fuel and Purchased Power Cost Recovery Factor
Estimated for the Period of : January 2020 through December 2020

	DOLLARS				mWh				c/kWh			
	Actual/ Estimated	Midcourse Filing	Difference Amount	%	Actual/ Estimated	Midcourse Filing	Difference Amount	%	Actual/ Estimated	Midcourse Filing	Difference Amount	%
1 Fuel Cost of System Net Generation (E3)	1,024,889,706	1,087,091,668	(62,201,962)	-6%	40,030,421	40,152,481	(122,059)	0%	2.560	2.707	-0.147	-5%
2 Coal Car Investment	-	0	-	0%			-	0%	0.000	0.000	0.000	0%
3 Adjustment to Fuel Cost	954,935	413,590	541,345	0%			-	0%	0.000	0.000	0.000	0%
4 TOTAL COST OF GENERATED POWER	1,025,844,641	1,087,505,258	(61,660,617)	-6%	40,030,421	40,152,481	(122,059)	0%	2.563	2.708	-0.146	-5%
5 Energy Cost of Purchased Power	51,672,621	25,787,425	25,885,195	100%	1,630,664	882,444	748,220	85%	3.169	2.922	0.247	8%
(Excl. Econ & Cogens) (E7)												
6 Energy Cost of Economy Purchases (E9)	3,500,516	1,726,221	1,774,295	103%	110,373	50,421	59,951	119%	3.172	3.424	-0.252	-7%
7 Payments to Qualifying Facilities (E8)	89,438,758	106,557,841	(17,119,083)	-16%	2,568,222	2,774,335	(206,113)	-7%	3.483	3.841	-0.358	-9%
8 TOTAL COST OF PURCHASED POWER	144,611,896	134,071,488	10,540,408	8%	4,309,258	3,707,201	602,057	16%	3.356	3.617	-0.261	-7%
9 TOTAL AVAILABLE mWh (LINE 4 + LINE 8)			-		44,339,679	43,859,681	479,998	1%	0.000	0.000	0.000	0%
10 Fuel Cost of Economy Sales (E6)	(3,909,810)	(5,636,579)	1,726,770	-31%	(132,558)	(172,089)	39,531	-23%	2.950	3.275	-0.326	-10%
10a Gain on Economy Sales (E6)	(1,128,563)	(1,481,447)	352,885	-24%	(132,558)	(172,089)	39,531	-23%	0.851	0.861	-0.009	-1%
10b Gain on Total Power Sales - 20% (E6)	0	0	-	100%			-	0%	0.000	0.000	0.000	0%
11 Fuel Cost of Stratified Sales (E6)	(49,177,021)	(23,571,099)	(25,605,921)	109%	(2,626,604)	(1,245,606)	(1,380,998)	111%	1.872	1.892	-0.020	-1%
12 TOTAL FUEL COST AND GAINS OF POWER SALES	(54,215,393)	(30,689,126)	(23,526,267)	77%	(2,759,161)	(1,417,695)	(1,341,467)	95%	1.965	2.165	-0.200	-9%
(LINES 10 + 10a + 10b + 11)												
13 Net Inadvertent Interchange					110,445	33,592	76,853					
14 TOTAL FUEL & NET POWER TRANSACTIONS	1,116,241,144	1,190,887,620	(74,646,476)	-6%	41,690,963	42,475,579	(784,616)	-2%	2.677	2.804	-0.126	-5%
(LINES 4 + 8 + 12 + 13)												
15 Net Unbilled					25,568	(227,858)	253,426	-111%	0.000	0.000	0.000	0%
16 Company Use					(165,751)	(181,976)	16,225	-9%	0.000	0.000	0.000	0%
17 T & D Losses					(2,567,001)	(2,786,714)	219,713	-8%	0.000	0.000	0.000	0%
18 SYSTEM mWh SALES	1,116,241,144	1,190,887,620	(74,646,476)	-6%	38,983,778	39,279,031	(295,252)	-1%	2.863	3.032	-0.169	-6%
19 Wholesale mWh Sales	(7,416,368)	(5,670,272)	(1,746,097)	31%	(262,713)	(186,476)	(76,237)	41%	2.823	3.041	-0.218	-7%
20 Jurisdictional mWh Sales	1,108,824,776	1,185,217,348	(76,392,573)	-6%	38,721,066	39,092,555	(371,489)	-1%	2.864	3.032	-0.168	-6%
20a Jurisdictional Loss Multiplier	1.00031	1.00031	0.00000	0%	1.00031	1.00034	-0.00003	0%				
21 Jurisdictional Sales Adjusted for Line Losses	1,109,170,633	1,185,586,888	(76,416,254)	-6%	38,721,066	39,092,555	(371,489)	-1%	2.865	3.033	-0.168	-6%
22 TRUE-UP	(61,083,424)	(77,026,561)	15,943,138	-21%	38,721,066	39,092,555	(371,489)	-1%	(0.158)	(0.197)	0.039	-20%
23 TOTAL JURISDICTIONAL FUEL COST	1,048,087,210	1,108,560,327	(60,473,117)	-5%	38,721,066	39,092,555	(371,489)	-1%	2.707	2.836	-0.129	-5%
24 Revenue Tax Factor	754,623	741,837	12,786	2%								
25 Fuel Factor Adjusted for Taxes	1,048,841,833	1,109,302,163	(60,460,330)	-5%	38,721,066	39,092,555	(371,489)	-1%	2.709	2.838	-0.129	-5%
26 GPIF **	2,591,697	2,591,697	-	0%	38,721,066	39,092,555	(371,489)	-1%	0.007	0.007	0.000	1%
27 Fuel Factor Adjusted for Taxes Including GPIF	1,051,433,530	1,111,893,860	(60,460,330)	-5%	38,721,066	39,092,555	(371,489)	-1%	2.715	2.844	-0.129	-5%
28 FUEL FACTOR ROUNDED TO NEAREST .001 c/kWh									2.715	2.844	-0.129	-5%

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Duke Energy Florida, LLC
Fuel and Purchased Power Cost Recovery Clause
Estimated for the Period of : January 2020 through December 2020

			Actual Jan-20	Actual Feb-20	Actual Mar-20	Actual Apr-20	Actual May-20	Actual Jun-20	Estimated Jul-20	Estimated Aug-20	Estimated Sep-20	Estimated Oct-20	Estimated Nov-20	Estimated Dec-20	TOTAL
1	Fuel Cost of System Net Generation		$74,992,301	$65,717,824	$73,293,028	$70,415,016	$87,128,507	$89,708,430	$91,270,574	$102,001,873	$96,405,019	$90,833,949	$85,974,737	$97,148,448	$1,024,889,706
1a	Adjustments to Fuel Cost		(12,011,163)	1,119,402	1,152,738	1,147,328	1,142,435	1,139,918	1,136,872	1,651,425	1,124,387	1,120,886	1,117,160	1,113,548	954,935
2	Fuel Cost of Power Sold		(65,028)	(82,184)	(46,687)	(85,510)	(64,389)	(211,899)	(666,950)	(893,645)	(640,967)	(258,600)	(269,399)	(624,551)	(3,909,810)
2a	Gains on Power Sales		(13,997)	(27,685)	(18,959)	(42,464)	(13,643)	(161,310)	(169,119)	(226,601)	(162,530)	(65,574)	(68,312)	(158,368)	(1,128,563)
2b	Gain on Total Power Sales - 20%		0	0	0	0	0	0	0	0	0	0	0	0	0
2c	Fuel Cost of Stratified Sales		(1,026,793)	(1,050,002)	(1,246,506)	(2,484,344)	(5,417,069)	(6,232,898)	(6,572,998)	(6,901,444)	(7,168,213)	(7,253,825)	(2,159,728)	(1,663,203)	(49,177,021)
3	Fuel Cost of Purchased Power (Excl Economy)		1,777,132	3,137,635	6,173,029	1,917,858	6,444,417	9,797,876	8,533,384	4,575,768	3,696,906	4,358,593	1,085,538	174,484	51,672,621
3a	Energy Payments to Qualifying Facilities		7,319,413	7,093,012	5,551,577	5,410,902	7,518,681	7,427,850	8,407,595	8,411,122	7,949,571	7,091,011	8,225,712	9,032,312	89,438,758
4	Energy Cost of Economy Purchases		143,759	406,521	1,053,448	485,384	407,645	188,921	177,886	113,649	178,038	128,590	91,292	125,383	3,500,516
5	Total System Fuel & Net Power Transactions		$71,115,625	$76,314,523	$85,911,668	$76,764,171	$97,146,585	$101,656,887	$102,117,245	$108,732,147	$101,382,212	$95,955,030	$93,997,000	$105,148,053	$1,116,241,144
6	Jurisdictional MWH Sold		2,640,090	2,661,152	2,818,044	3,239,130	2,981,766	3,450,388	3,923,462	3,994,662	3,898,898	3,525,887	2,811,544	2,776,042	38,721,066
7	Jurisdictional % of Total Sales		99.46%	99.31%	99.07%	99.22%	99.33%	99.25%	99.07%	99.07%	99.55%	99.55%	99.57%	99.58%	99.33%
8	Jurisdicitonal Fuel & Net Power Transactions		70,731,601	75,787,953	85,112,689	76,165,410	96,495,703	100,894,461	101,167,554	107,720,938	100,925,992	95,523,232	93,592,813	104,706,431	1,108,824,776
9	Jurisdictional Loss Multiplier		1.00034	1.00031	1.00031	1.00031	1.00031	1.00031	1.00031	1.00031	1.00031	1.00031	1.00031	1.00031	1.00031
10	Jurisdictional Fuel & Net Power Transactions		70,755,650	75,811,447	85,139,074	76,189,021	96,525,617	100,925,738	101,198,916	107,754,331	100,957,279	95,552,845	93,621,826	104,738,890	1,109,170,633
11	Adjusted System Sales	MWH	2,654,517	2,679,511	2,844,453	3,264,474	3,001,736	3,476,349	3,960,418	4,032,097	3,916,698	3,541,967	2,823,725	2,787,834	38,983,778
12	System Cost per MWH Sold	c/kwh	2.6791	2.8480	3.0203	2.3515	3.2363	2.9242	2.5784	2.6967	2.5885	2.7091	3.3288	3.7717	2.8633
13	Jurisdictional Loss Multiplier	x	1.00034	1.00031	1.00031	1.00031	1.00031	1.00031	1.00031	1.00031	1.00031	1.00031	1.00031	1.00031	1.00031
14	Jurisdictional Cost per MWH Sold	c/kwh	2.6800	2.8488	3.0212	2.3521	3.2372	2.9251	2.5793	2.6975	2.5894	2.7100	3.3299	3.7730	2.8645
15	Prior Period True-Up	+	0.0457	0.0453	0.0428	0.0372	-2.5833	0.0349	0.0307	0.0302	0.0309	0.0342	0.0429	0.0434	-0.1578
16	Total Jurisdictional Fuel Expense	c/kwh	2.7257	2.8941	3.0640	2.3894	0.6539	2.9600	2.6100	2.7276	2.6203	2.7442	3.3728	3.8164	2.7068
17	Revenue Tax Multiplier	x	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072
18	Recovery Factor Adjusted for Taxes	c/kwh	2.7277	2.8962	3.0662	2.3911	0.6544	2.9621	2.6119	2.7296	2.6222	2.7462	3.3752	3.8191	2.7087
19	GPIF	+	0.0082	0.0081	0.0077	0.0067	0.0072	0.0063	0.0055	0.0054	0.0055	0.0061	0.0077	0.0078	0.0067
20	Total Recovery Factor (rounded .001)	c/kwh	2.736	2.904	3.074	2.398	0.662	2.968	2.617	2.735	2.628	2.752	3.383	3.827	2.715

Docket No. 20200001-EI
Exhibit CAM-2, Part 1
Schedule E3

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Duke Energy Florida, LLC
Generating System Comparative Data by Fuel Type
Estimated for the Period of : January 2020 through December 2020

			Actual Jan-20	Actual Feb-20	Actual Mar-20	Actual Apr-20	Actual May-20	Actual Jun-20	Subtotal
	FUEL COST OF SYSTEM NET GENERATION ($)								
1	LIGHT OIL		203,121	504,375	586,296	533,872	1,319,347	1,497,965	4,644,976
2	COAL		0	0	1,557,446	5,697,251	12,417,961	12,347,466	32,020,124
3	GAS		74,789,181	65,213,448	71,149,285	64,183,893	73,391,199	75,863,000	424,590,006
4	OTHER		0	0	0	0	0	0	0
5	TOTAL	$	74,992,301	65,717,824	73,293,028	70,415,016	87,128,507	89,708,430	461,255,106
	SYSTEM NET GENERATION (MWH)								
6	LIGHT OIL		1,107	1,773	553	1,343	503	1,913	7,191
7	COAL		0	0	35,102	147,016	313,029	303,866	799,013
8	GAS		2,772,351	2,536,287	2,953,481	2,756,018	2,944,556	3,417,419	17,380,112
9	SOLAR		30,015	31,310	52,320	61,887	83,741	76,819	336,092
10	OTHER		0	0	0	0	0	0	0
11	TOTAL	MWH	2,803,473	2,569,370	3,041,455	2,966,264	3,341,829	3,800,017	18,522,409
	UNITS OF FUEL BURNED								
12	LIGHT OIL	BBL	1,792	4,616	5,425	4,760	10,138	12,892	39,623
13	COAL	TON	0	0	17,493	61,653	140,193	143,523	362,862
14	GAS	MCF	19,744,076	18,695,068	22,283,497	20,472,403	21,849,351	25,649,038	128,693,433
15	OTHER	BBL	0	0	0	0	0	0	0
	BTUS BURNED (MMBTU)								
16	LIGHT OIL		10,335	26,645	31,140	27,431	12,906	74,337	182,794
17	COAL		0	0	378,584	1,510,745	3,387,063	3,361,596	8,637,987
18	GAS		20,233,462	19,176,786	22,873,368	21,041,082	22,399,972	26,195,265	131,919,936
19	OTHER		0	0	0	0	0	0	0
20	TOTAL	MMBTU	20,243,797	19,203,431	23,283,091	22,579,258	25,799,940	29,631,198	140,740,717
	GENERATION MIX (% MWH)								
21	LIGHT OIL		0.04%	0.07%	0.02%	0.05%	0.02%	0.05%	0.04%
22	COAL		0.00%	0.00%	1.15%	4.96%	9.37%	8.00%	4.31%
23	GAS		98.89%	98.71%	97.11%	92.91%	88.11%	89.93%	93.83%
24	SOLAR		1.07%	1.22%	1.72%	2.09%	2.51%	2.02%	1.82%
25	OTHER		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
26	TOTAL	%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
	FUEL COST PER UNIT								
27	LIGHT OIL	$/BBL	113.35	109.27	108.07	112.16	130.14	116.19	117.23
28	COAL	$/TON	0.00	0.00	89.03	92.41	88.58	86.03	88.24
29	GAS	$/MCF	3.79	3.49	3.19	3.14	3.36	2.96	3.30
30	OTHER	$/BBL	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	FUEL COST PER MMBTU ($/MMBTU)								
31	LIGHT OIL		19.65	18.93	18.83	19.46	102.23	20.15	25.41
32	COAL		0.00	0.00	4.11	3.77	3.67	3.67	3.71
33	GAS		3.70	3.40	3.11	3.05	3.28	2.90	3.22
34	OTHER		0.00	0.00	0.00	0.00	0.00	0.00	0.00
35	TOTAL	$/MMBTU	3.70	3.42	3.15	3.12	3.38	3.03	3.28
	BTU BURNED PER KWH (BTU/KWH)								
36	LIGHT OIL		9,335	15,028	56,361	20,422	25,677	38,859	25,418
37	COAL		0	0	10,785	10,276	10,820	11,063	10,811
38	GAS		7,298	7,561	7,745	7,635	7,607	7,665	7,590
39	OTHER		0	0	0	0	0	0	0
40	TOTAL	BTU/KWH	7,221	7,474	7,655	7,612	7,720	7,798	7,598
	GENERATED FUEL COST PER KWH (C/KWH)								
41	LIGHT OIL		18.35	28.45	106.11	39.75	262.50	78.31	64.59
42	COAL		0.00	0.00	4.44	3.88	3.97	4.06	4.01
43	GAS		2.70	2.57	2.41	2.33	2.49	2.22	2.44
44	OTHER		0.00	0.00	0.00	0.00	0.00	0.00	0.00
45	TOTAL	C/KWH	2.67	2.56	2.41	2.37	2.61	2.36	2.49

Duke Energy Florida, LLC
Generating System Comparative Data by Fuel Type
Estimated for the Period of : January 2020 through December 2020

REVISED

			Estimated Jul-20	Estimated Aug-20	Estimated Sep-20	Estimated Oct-20	Estimated Nov-20	Estimated Dec-20	Total
	FUEL COST OF SYSTEM NET GENERATION ($)								
1	LIGHT OIL		932,159	913,933	1,011,462	950,529	762,685	1,124,178	10,339,922
2	COAL		8,114,040	16,311,312	14,289,480	16,111,023	18,889,783	22,074,322	127,810,084
3	GAS		82,224,375	84,776,628	81,104,077	73,772,397	66,322,269	73,949,948	886,739,700
4	OTHER		0	0	0	0	0	0	0
5	TOTAL	$	91,270,574	102,001,873	96,405,019	90,833,949	85,974,737	97,148,448	1,024,889,706
	SYSTEM NET GENERATION (MWH)								
6	LIGHT OIL		3,405	3,262	3,576	3,167	3,078	4,162	27,842
7	COAL		172,937	397,784	347,442	408,473	514,959	645,873	3,286,481
8	GAS		3,816,510	3,771,802	3,544,614	3,000,650	2,205,798	2,235,990	35,955,476
9	SOLAR		85,203	81,472	74,791	71,123	60,707	51,234	760,622
10	OTHER		0	0	0	0	0	0	0
11	TOTAL	MWH	4,078,055	4,254,320	3,970,423	3,483,413	2,784,543	2,937,259	40,030,421
	UNITS OF FUEL BURNED								
12	LIGHT OIL	BBL	7,977	7,738	8,638	7,906	6,503	9,719	88,104
13	COAL	TON	79,360	181,845	158,106	182,641	219,903	275,067	1,459,784
14	GAS	MCF	28,506,746	27,948,367	26,147,693	22,397,111	15,715,665	15,197,117	264,606,132
15	OTHER	BBL	0	0	0	0	0	0	0
	BTUS BURNED (MMBTU)								
16	LIGHT OIL		46,480	45,092	50,343	46,068	37,875	56,629	465,281
17	COAL		1,842,233	4,242,991	3,709,116	4,325,020	5,252,455	6,566,210	34,576,012
18	GAS		28,506,746	27,948,367	26,147,693	22,397,111	15,715,665	15,197,117	267,832,635
19	OTHER		0	0	0	0	0	0	0
20	TOTAL	MMBTU	30,395,459	32,236,450	29,907,152	26,768,199	21,005,995	21,819,956	302,873,928
	GENERATION MIX (% MWH)								
21	LIGHT OIL		0.08%	0.08%	0.09%	0.09%	0.11%	0.14%	0.07%
22	COAL		4.24%	9.35%	8.75%	11.73%	18.49%	21.99%	8.21%
23	GAS		93.59%	88.66%	89.28%	86.14%	79.22%	76.13%	89.82%
24	SOLAR		2.09%	1.92%	1.88%	2.04%	2.18%	1.74%	1.90%
25	OTHER		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
26	TOTAL	%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
	FUEL COST PER UNIT								
27	LIGHT OIL	$/BBL	116.86	118.11	117.09	120.23	117.28	115.67	117.36
28	COAL	$/TON	102.24	89.70	90.38	88.21	85.90	80.25	87.55
29	GAS	$/MCF	2.88	3.03	3.10	3.29	4.22	4.87	3.35
30	OTHER	$/BBL	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	FUEL COST PER MMBTU ($/MMBTU)								
31	LIGHT OIL		20.06	20.27	20.09	20.63	0.00	0.00	22.22
32	COAL		4.40	3.84	3.85	3.73	3.60	0.00	3.70
33	GAS		2.88	3.03	3.10	3.29	4.22	4.87	3.31
34	OTHER		0.00	0.00	0.00	0.00	0.00	0.00	0.00
35	TOTAL	$/MMBTU	3.00	3.16	3.22	3.39	4.09	4.45	3.38
	BTU BURNED PER KWH (BTU/KWH)								
36	LIGHT OIL		13,652	13,822	14,077	14,544	12,304	13,607	16,712
37	COAL		10,653	10,667	10,675	10,588	10,200	10,166	10,521
38	GAS		7,469	7,410	7,377	7,464	7,125	6,797	7,449
39	OTHER		0	0	0	0	0	0	0
40	TOTAL	BTU/KWH	7,453	7,577	7,532	7,684	7,544	7,429	7,566
	GENERATED FUEL COST PER KWH (C/KWH)								
41	LIGHT OIL		27.38	28.01	28.28	30.01	24.78	27.01	37.14
42	COAL		4.69	4.10	4.11	3.94	3.67	3.42	3.89
43	GAS		2.15	2.25	2.29	2.46	3.01	3.31	2.47
44	OTHER		0.00	0.00	0.00	0.00	0.00	0.00	0.00
45	TOTAL	C/KWH	2.24	2.40	2.43	2.61	3.09	3.31	2.56

Duke Energy Florida, LLC
System Net Generation and Fuel Cost
Estimated for the Period of: Jul-20

	(A) PLANT/UNIT		(B) NET CAPACITY (MW)	(C) NET GENERATION (MWH)	(D) CAPACITY FACTOR (%)	(E) EQUIV AVAIL FACTOR (%)	(F) OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE (BTU/KWH)	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MMBTU)	(L) AS BURNED FUEL COST ($)	(M) FUEL COST PER KWH (C/KWH)
1	CRYSTAL RIVER	4	732	63,313	11 6	95.16	55.4	10,745	COAL	29,307 TONS	23.21	680,320	3,213,705	5 08
2	CRYSTAL RIVER	5	712	109,624	20.7	90.32	50.8	10,599	COAL	50,053 TONS	23.21	1,161,913	4,900,335	4.47
3	ANCLOTE	1	517	153,379	39 9	93.23	44.3	10,729	GAS	1,645,580 MCF	1.00	1,645,580	4,803,520	3.13
4	ANCLOTE	2	521	152,803	39.4	98.06	40.2	11,444	GAS	1,748,735 MCF	1.00	1,748,735	4,983,629	3 26
5	AVON PARK	1-2	69	75	0.1	93.39	18.1	16,187	GAS	1,214 MCF	1.00	1,214	3,501	4 67
6	BARTOW	1-4	228	1,184	0 8	88.95	18.0	14,095	GAS	16,690 MCF	1.00	16,690	48,123	4 06
7	BARTOW CC	1	1279	678,299	71 3	92.26	77.3	7,186	GAS	4,874,168 MCF	1.00	4,874,168	14,054,148	2 07
8	CITRUS CC	1-2	1640	1,109,441	90 9	94.84	96.4	6,541	GAS	7,256,362 MCF	1.00	7,256,362	20,922,954	1 89
9	DEBARY	1-10	785	20,887	3.7	81.10	10.0	12,798	GAS	267,325 MCF	1.00	267,325	770,802	3 69
10	H NES CC	1-4	2,204	1,225,187	74 8	95.64	79.1	7,230	GAS	8,858,277 MCF	1.00	8,858,277	25,541,903	2 08
11	INT CITY	1-14	1,186	33,053	3 9	92.49	6.5	12,785	GAS	422,585 MCF	1.00	422,585	1,218,480	3 69
12	OSPREY	1	505	298,029	79 3	96.56	84.1	7,559	GAS	2,252,846 MCF	1.00	2,252,846	6,495,842	2.18
13	SUWANNEE CT	1-3	200	4,023	2 8	80.81	24.8	13,496	GAS	54,288 MCF	1.00	54,288	156,536	3 89
14	TIGER BAY	1	225	110,120	65 8	93.55	88.5	7,508	GAS	826,774 MCF	1.00	826,774	2,383,914	2.16
15	UNIV OF FLA.	1	47	30,031	85 9	93.87	91.5	9,387	GAS	281,902 MCF	1.00	281,902	841,023	2 80
16	AVON PARK	1-2	69	0	0 0	93.39	18.1	0	LIGHT OIL	0 BBLS		0	0	0 00
17	BARTOW	1-4	228	169	0 8	88.95	18.0	15,614	LIGHT OIL	452 BBLS	5.83	2,635	51,593	30 57
18	BARTOW CC	1	1,279	0	71 3	92.26	77.3	0	LIGHT OIL	0 BBLS	5.83	0	0	0 00
19	BAYBORO	1-4	231	167	0.1	91.94	18.1	13,849	LIGHT OIL	397 BBLS	5.83	2,310	59,719	35 80
20	DEBARY	1-10	785	794	3.7	81.10	10.0	13,229	LIGHT OIL	1,804 BBLS	5.83	10,506	224,040	28 21
21	H NES CC	1-4	2,204	871	74 8	95.64	79.1	7,156	LIGHT OIL	1,070 BBLS	5.83	6,235	94,948	10 90
22	OTHER		0	0	0 0	0.00	0.0	0	LIGHT OIL	0 BBLS	5.83	0	0	0 00
23	INT CITY	1-14	1,186	1,262	3 9	92.49	6.5	12,892	LIGHT OIL	2,791 BBLS	5.83	16,264	303,650	24 07
24	SUWANNEE CT	1-3	200	142	2 8	80.81	24.8	13,309	LIGHT OIL	324 BBLS	5.83	1,890	32,688	23 02
25	OTHER - START UP	0	-	0	-	0.00	0.0	0	LIGHT OIL	1,139 BBLS	5.83	6,640	165,521	0 00
26	SOLAR	1	363	85,203	31 5	0.00	57.1	0	SOLAR	0 N/A		0	0	0 00
27	TOTAL			4,078,055								30,395,459	91,270,574	2 24

Duke Energy Florida, LLC
System Net Generation and Fuel Cost
Estimated for the Period of: Aug-20

	(A)		(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)		(J)	(K)	(L)	(M)
	PLANT/UNIT		NET CAPACITY (MW)	NET GENERATION (MWH)	CAPACITY FACTOR (%)	EQUIV AVAIL FACTOR (%)	OUTPUT FACTOR (%)	AVG. NET HEAT RATE (BTU/KWH)	FUEL TYPE	FUEL BURNED (UNITS)		FUEL HEAT VALUE (BTU/UNIT)	FUEL BURNED (MMBTU)	AS BURNED FUEL COST ($)	FUEL COST PER KWH (C/KWH)
1	CRYSTAL RIVER	4	732	275,763	50.6	89.35	56.7	10,711	COAL	126,585	TONS	23.33	2,953,607	11,028,560	4.00
2	CRYSTAL RIVER	5	712	122,021	23.0	90.65	52.2	10,567	COAL	55,260	TONS	23.33	1,289,384	5,282,752	4.33
3	ANCLOTE	1	517	134,682	35.0	94.52	38.7	10,845	GAS	1,460,630	MCF	1.00	1,460,630	4,475,896	3.32
4	ANCLOTE	2	521	131,977	34.0	96.13	35.4	11,656	GAS	1,538,268	MCF	1.00	1,538,268	4,617,586	3.50
5	AVON PARK	1-2	228	15	0.0	92.26	3.3	16,733	GAS	251	MCF	1.00	251	762	5.08
6	BARTOW	1-4	1,279	1,026	0.1	87.58	3.2	14,136	GAS	14,509	MCF	1.00	14,509	43,997	4.29
7	BARTOW CC	1	1279	701,158	73.7	96.13	76.6	7,172	GAS	5,028,383	MCF	1.00	5,028,383	15,247,437	2.17
8	CITRUS CC	1-2	1640	1,121,913	91.9	96.13	96.1	6,522	GAS	7,316,567	MCF	1.00	7,316,567	22,185,841	1.98
9	DEBARY	1-10	785	15,001	2.7	79.42	10.0	12,812	GAS	192,199	MCF	1.00	192,199	582,798	3.89
10	HINES CC	1-4	2,204	1,212,740	74.0	95.72	77.9	7,237	GAS	8,776,193	MCF	1.00	8,776,193	26,611,832	2.19
11	NT CITY	1-14	1,186	22,757	2.7	92.58	6.4	12,794	GAS	291,144	MCF	1.00	291,144	882,825	3.88
12	OSPREY	1	505	293,389	78.1	96.36	83.8	7,566	GAS	2,219,902	MCF	1.00	2,219,902	6,731,353	2.29
13	SUWANNEE CT	1-3	200	3,547	2.5	83.07	24.8	13,520	GAS	47,953	MCF	1.00	47,953	145,407	4.10
14	TIGER BAY	1	225	102,122	61.0	91.94	88.5	7,514	GAS	767,355	MCF	1.00	767,355	2,326,832	2.28
15	UNIV OF FLA.	1	47	31,476	90.0	98.39	91.5	9,373	GAS	295,013	MCF	1.00	295,013	924,062	2.94
16	AVON PARK	1-2	69	0	0.0	92.26	10.9	0	LIGHT O L	0	BBLS		0	0	0.00
17	BARTOW	1-4	228	167	0.7	87.58	18.0	15,485	LIGHT O L	443	BBLS	5.84	2,585	50,701	30.37
18	BARTOW CC	1	1,279	0	73.7	96.13	76.6	0	LIGHT O L	0	BBLS	5.84	0	0	0.00
19	BAYBORO	1-4	231	158	0.1	92.50	17.1	13,854	LIGHT O L	376	BBLS	5.84	2,189	56,830	35.97
20	DEBARY	1-10	785	836	2.7	79.42	10.0	13,147	LIGHT O L	1,886	BBLS	5.84	10,989	233,517	27.94
21	HINES CC	1-4	2,204	868	74.0	95.72	77.9	7,183	LIGHT O L	1,070	BBLS	5.84	6,235	94,948	10.94
22	OTHER		0	0	0.0	0.00	0.0	0	LIGHT O L	0	BBLS	5.84	0	0	0.00
23	NT CITY	1-14	1,186	1,112	2.7	92.58	6.4	12,959	LIGHT O L	2,472	BBLS	5.84	14,409	272,192	24.48
24	SUWANNEE CT	1-3	200	122	2.5	83.07	24.8	13,388	LIGHT O L	280	BBLS	5.84	1,630	28,588	23.48
25	OTHER - START UP	0	-	0	-	0.00	0.0	0	LIGHT O L	1,211	BBLS	5.84	7,055	177,157	0.00
26	SOLAR	1	363	81,472	30.2	0.00	55.7	0	SOLAR	0	N/A		0	0	0.00
27	TOTAL			4,254,320									32,236,450	102,001,873	2.40

Duke Energy Florida, LLC
System Net Generation and Fuel Cost
Estimated for the Period of: Sep-20

	(A) PLANT/UNIT		(B) NET CAPACITY (MW)	(C) NET GENERATION (MWH)	(D) CAPACITY FACTOR (%)	(E) EQUIV AVAIL FACTOR (%)	(F) OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE (BTU/KWH)	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MMBTU)	(L) AS BURNED FUEL COST ($)	(M) FUEL COST PER KWH (C/KWH)
1	CRYSTAL RIVER	4	732	274,599	52.1	92 00	56.7	10,713	COAL	125,392 TONS	23.46	2,941,665	10,845,681	3.95
2	CRYSTAL RIVER	5	712	72,843	14.2	87 00	54.1	10,536	COAL	32,714 TONS	23.46	767,451	3,443,799	4.73
3	ANCLOTE	1	517	111,578	30.0	93 00	36.6	10,928	GAS	1,219,312 MCF	1 00	1,219,312	3,887,731	3.48
4	ANCLOTE	2	521	118,071	31.5	96 00	33.1	11,772	GAS	1,389,953 MCF	1 00	1,389,953	4,202,905	3.56
5	AVON PARK	1-2	228	10	0.0	95 34	0.0	16,700	GAS	167 MCF	1 00	167	519	5.19
6	BARTOW	1-4	1,279	942	0.1	87.75	3.2	14,118	GAS	13,293 MCF	1 00	13,293	41,218	4.38
7	BARTOW CC	1	1279	641,657	69.7	91 33	76.2	7,172	GAS	4,602,150 MCF	1 00	4,602,150	14,270,040	2.22
8	CITRUS CC	1-2	1640	1,094,234	92.7	97 00	95.8	6,521	GAS	7,135,140 MCF	1 00	7,135,140	22,124,168	2.02
9	DEBARY	1-10	785	11,442	2.2	79.47	9.9	12,820	GAS	146,695 MCF	1 00	146,695	454,865	3.98
10	HINES CC	1-4	2,204	1,133,944	71.5	93.17	79.0	7,235	GAS	8,204,194 MCF	1 00	8,204,194	25,439,018	2.24
11	INT CITY	1-14	1,186	19,276	2.4	93.48	6.4	12,798	GAS	246,696 MCF	1 00	246,696	764,942	3.97
12	OSPREY	1	505	276,731	76.1	94.44	83.5	7,567	GAS	2,093,971 MCF	1 00	2,093,971	6,492,847	2.35
13	SUWANNEE CT	1-3	200	2,435	1.8	82 50	25.1	13,571	GAS	33,044 MCF	1 00	33,044	102,461	4.21
14	TIGER BAY	1	225	105,502	65.1	94 33	88.1	7,513	GAS	792,647 MCF	1 00	792,647	2,457,786	2.33
15	UNIV OF FLA.	1	47	28,793	85.1	93 00	91.4	9,392	GAS	270,431 MCF	1 00	270,431	865,577	3.01
16	AVON PARK	1-2	69	0	0.0	95 34	0.0	0	LIGHT OIL	0 BBLS		0	0	0.00
17	BARTOW	1-4	228	172	0.7	87.75	18.1	15,514	LIGHT OIL	458 BBLS	5 83	2,672	52,247	30.34
18	BARTOW CC	1	1,279	0	69.7	91 33	76.2	0	LIGHT OIL	0 BBLS	5 83	0	0	0.00
19	BAYBORO	1-4	231	158	0.1	91.75	17.1	13,854	LIGHT OIL	376 BBLS	5 83	2,189	56,863	35.99
20	DEBARY	1-10	785	800	2.2	79.47	9.9	13,157	LIGHT OIL	1,806 BBLS	5 83	10,520	224,309	28.05
21	HINES CC	1-4	2,204	782	71.5	93.17	79.0	7,178	LIGHT OIL	963 BBLS	5 83	5,611	86,496	11.06
22	OTHER		0	0	0.0	0 00	0.0	0	LIGHT OIL	0 BBLS	5 83	0	0	0.00
23	INT CITY	1-14	1,186	1,543	2.4	93.48	6.4	12,853	LIGHT OIL	3,402 BBLS	5 83	19,833	364,131	23.60
24	SUWANNEE CT	1-3	200	122	1.8	82 50	25.1	13,424	LIGHT OIL	280 BBLS	5 83	1,633	28,617	23.52
25	OTHER - START UP	0	-	0	-	0 00	0.0	0	LIGHT OIL	1,353 BBLS	5 83	7,885	198,799	0.00
26	SOLAR	1	363	74,791	28.6	0 00	54.5	0	SOLAR	0 N/A		0	0	0.00
27	TOTAL			3,970,423								29,907,152	96,405,019	2.43

Duke Energy Florida, LLC
System Net Generation and Fuel Cost
Estimated for the Period of: Oct-20

(A) PLANT/UNIT		(B) NET CAPACITY (MW)	(C) NET GENERATION (MWH)	(D) CAPACITY FACTOR (%)	(E) EQUIV AVA L FACTOR (%)	(F) OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE (BTU/KWH)	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)		(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MMBTU)	(L) AS BURNED FUEL COST ($)	(M) FUEL COST PER KWH (C/KWH)
1 CRYSTAL RIVER	4	732	306,524	56 3	93.23	60.3	10,618	COAL	137,441	TONS	23.68	3,254,674	11,704,164	3 82
2 CRYSTAL RIVER	5	712	101,949	19 2	91.94	56.2	10,499	COAL	45,200	TONS	23.68	1,070,346	4,406,859	4 32
3 ANCLOTE	1	517	126,128	32 8	93.87	36.7	10,902	GAS	1,375,045	MCF	1.00	1,375,045	4,457,212	3 53
4 ANCLOTE	2	521	108,325	27 9	94.19	33.9	11,733	GAS	1,270,956	MCF	1.00	1,270,956	4,256,529	3 93
5 AVON PARK	1-2	228	0	0 0	0.00	0.0	0	GAS	0	MCF		0	0	0 00
6 BARTOW	1-4	1,279	461	0.1	87.82	3.0	14,137	GAS	6,511	MCF	1.00	6,511	21,443	4 66
7 BARTOW CC	1	1279	598,618	62 9	81.95	66.3	7,246	GAS	4,337,717	MCF	1.00	4,337,717	14,284,858	2 39
8 CITRUS CC	1-2	1640	700,557	57.4	58.52	96.2	6,533	GAS	4,576,650	MCF	1.00	4,576,650	15,071,706	2.15
9 DEBARY	1-10	785	8,357	1 6	80.32	9.9	12,811	GAS	107,063	MCF	1.00	107,063	352,577	4 22
10 H NES CC	1-4	2,204	996,943	60 9	71.14	83.8	7,181	GAS	7,159,122	MCF	1.00	7,159,122	23,576,233	2 36
11 INT CITY	1-14	1,186	9,459	1 2	64.81	6.5	12,809	GAS	121,165	MCF	1.00	121,165	399,016	4 22
12 OSPREY	1	505	304,576	81.1	94.57	88.2	7,544	GAS	2,297,852	MCF	1.00	2,297,852	7,567,226	2.48
13 SUWANNEE CT	1-3	200	2,600	1 8	84.68	24.7	13,531	GAS	35,187	MCF	1.00	35,187	115,878	4.46
14 TIGER BAY	1	225	128,835	77 0	92.90	88.2	7,465	GAS	961,707	MCF	1.00	961,707	3,167,067	2.46
15 UNIV OF FLA.	1	47	15,790	45 2	95.62	91.5	9,382	GAS	148,136	MCF	1.00	148,136	502,652	3.18
16 AVON PARK	1-2	69	0	0 0	0.00	0.0	0	LIGHT OIL	0	BBLS		0	0	0 00
17 BARTOW	1-4	228	155	0.4	87.82	16.9	15,175	LIGHT OIL	402	BBLS	5.83	2,345	46,412	30 03
18 BARTOW CC	1	1,279	0	62 9	81.95	66.3	0	LIGHT OIL	0	BBLS	5.83	0	0	0 00
19 BAYBORO	1-4	231	158	0.1	93.95	17.1	13,852	LIGHT OIL	377	BBLS	5.83	2,190	56,924	36 01
20 DEBARY	1-10	785	795	1 6	80.32	9.9	13,151	LIGHT OIL	1,794	BBLS	5.83	10,453	223,000	28 06
21 H NES CC	1-4	2,204	874	60 9	71.14	83.8	7,130	LIGHT OIL	1,070	BBLS	5.83	6,235	94,948	10 86
22 OTHER		0	0	0 0	0.00	0.0	0	LIGHT OIL	0	BBLS	5.83	0	0	0 00
23 INT CITY	1-14	1,186	1,074	1 2	64.81	6.5	12,849	LIGHT OIL	2,367	BBLS	5.83	13,799	261,854	24 38
24 SUWANNEE CT	1-3	200	112	1 8	84.68	24.7	13,451	LIGHT OIL	257	BBLS	5.83	1,501	26,534	23.78
25 OTHER - START UP	0	-	0	-	0.00	0.0	0	LIGHT OIL	1,639	BBLS	5.83	9,545	240,857	0 00
26 SOLAR	1	363	71,123	26 3	0.00	52.8	0	SOLAR	0	N/A		0	0	0 00
27 TOTAL			3,483,413									26,768,199	90,833,949	2 61

Duke Energy Florida, LLC
System Net Generation and Fuel Cost
Estimated for the Period of: Nov-20

(A) PLANT/UNIT		(B) NET CAPACITY (MW)	(C) NET GENERATION (MWH)	(D) CAPACITY FACTOR (%)	(E) EQUIV AVAIL FACTOR (%)	(F) OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE (BTU/KWH)	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MMBTU)	(L) AS BURNED FUEL COST ($)	(M) FUEL COST PER KWH (C/KWH)
1 CRYSTAL RIVER	4	732	246,448	46.8	94.00	66.9	10,245	COAL	105,706 TONS	23.89	2,524,823	9,112,294	3.70
2 CRYSTAL RIVER	5	712	268,511	52.4	91.00	61.9	10,158	COAL	114,197 TONS	23.89	2,727,632	9,777,489	3.64
3 ANCLOTE	1	517	44,758	12.0	94.33	23.3	11,438	GAS	511,950 MCF	1.00	511,950	1,909,885	4.27
4 ANCLOTE	2	521	21,774	5.8	95.67	32.7	11,361	GAS	247,379 MCF	1.00	247,379	1,294,229	5.94
5 AVON PARK	1-2	228	0	0.0	0.00	0.0	0	GAS	0 MCF		0	0	0.00
6 BARTOW	1-4	1,279	194	0.0	70.25	3.0	14,107	GAS	2,731 MCF	1.00	2,731	11,525	5.95
7 BARTOW CC	1	1279	491,390	53.4	73.35	56.2	7,198	GAS	3,537,162 MCF	1.00	3,537,162	14,925,649	3.04
8 CITRUS CC	1-2	1640	704,370	59.7	61.50	94.8	6,524	GAS	4,595,079 MCF	1.00	4,595,079	19,389,702	2.75
9 DEBARY	1-10	785	2,589	0.6	79.43	9.0	12,721	GAS	32,931 MCF	1.00	32,931	138,959	5.37
10 H NES CC	1-4	2,204	790,197	49.9	70.79	84.8	7,110	GAS	5,617,975 MCF	1.00	5,617,975	23,705,988	3.00
11 INT CITY	1-14	1,186	3,057	0.5	77.45	6.4	12,613	GAS	38,556 MCF	1.00	38,556	162,692	5.32
12 OSPREY	1	505	118,721	32.7	95.25	67.2	7,530	GAS	894,005 MCF	1.00	894,005	3,772,404	3.18
13 SUWANNEE CT	1-3	200	791	0.6	81.96	23.5	13,507	GAS	10,679 MCF	1.00	10,679	45,061	5.70
14 TIGER BAY	1	225	20,116	12.4	93.12	86.8	7,622	GAS	153,325 MCF	1.00	153,325	646,980	3.22
15 UNIV OF FLA.	1	47	7,843	23.2	95.00	91.7	9,421	GAS	73,893 MCF	1.00	73,893	319,195	4.07
16 AVON PARK	1-2	69	0	0.0	0.00	0.0	0	LIGHT OIL	0 BBLS		0	0	0.00
17 BARTOW	1-4	228	157	0.2	70.25	17.1	15,216	LIGHT OIL	411 BBLS	5.83	2,395	47,315	30.06
18 BARTOW CC	1	1,279	0	53.4	73.35	56.2	0	LIGHT OIL	0 BBLS	5.83	0	0	0.00
19 BAYBORO	1-4	231	150	0.1	91.08	16.2	14,860	LIGHT OIL	381 BBLS	5.83	2,223	57,734	38.59
20 DEBARY	1-10	785	742	0.6	79.43	9.0	12,975	LIGHT OIL	1,654 BBLS	5.83	9,628	206,836	27.87
21 H NES CC	1-4	2,204	899	49.9	70.79	84.8	7,109	LIGHT OIL	1,097 BBLS	5.83	6,388	97,019	10.80
22 OTHER		0	0	0.0	0.00	0.0	0	LIGHT OIL	0 BBLS	5.83	0	0	0.00
23 INT CITY	1-14	1,186	1,029	0.5	77.45	6.4	12,582	LIGHT OIL	2,223 BBLS	5.83	12,952	247,516	24.05
24 SUWANNEE CT	1-3	200	101	0.6	81.96	23.5	13,680	LIGHT OIL	239 BBLS	5.83	1,384	24,692	24.41
25 OTHER - START UP	0	-	0	-	0.00	0.0	0	LIGHT OIL	498 BBLS	5.83	2,905	81,573	0.00
26 SOLAR	1	363	60,707	23.2	0.00	51.5	0	SOLAR	0 N/A		0	0	0.00
27 TOTAL			2,784,543								21,005,995	85,974,737	3.09

Duke Energy Florida, LLC
System Net Generation and Fuel Cost
Estimated for the Period of: Dec-20

	(A)		(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
	PLANT/UNIT		NET CAPACITY (MW)	NET GENERATION (MWH)	CAPACITY FACTOR (%)	EQUIV AVAIL FACTOR (%)	OUTPUT FACTOR (%)	AVG. NET HEAT RATE (BTU/KWH)	FUEL TYPE	FUEL BURNED (UNITS)	FUEL HEAT VALUE (BTU/UNIT)	FUEL BURNED (MMBTU)	AS BURNED FUEL COST ($)	FUEL COST PER KWH (C/KWH)
1	CRYSTAL RIVER	4	732	355,795	65.3	96.13	69.4	10,207	COAL	152,132 TONS	23.87	3,631,587	12,120,474	3.41
2	CRYSTAL RIVER	5	712	290,078	54.8	91 29	64.9	10,117	COAL	122,935 TONS	23.87	2,934,623	9,953,848	3.43
3	ANCLOTE	1	517	0	0.0	91 94	0.0	0	GAS	0 MCF		0	167,377	0 00
4	ANCLOTE	2	521	11,176	2.9	94.19	12.5	14,718	GAS	164,483 MCF	1.00	164,483	632,700	5 66
5	AVON PARK	1-2	228	0	0.0	0 00	0.0	0	GAS	0 MCF		0	0	0 00
6	BARTOW	1-4	1,279	190	0.0	87.18	2.7	14,959	GAS	2,849 MCF	1.00	2,849	13,855	7 27
7	BARTOW CC	1	1279	638,111	67.1	95.16	70.5	6,935	GAS	4,425,580 MCF	1.00	4,425,580	21,526,835	3 37
8	CITRUS CC	1-2	1640	1,229,900	100.8	95 81	105.6	6,490	GAS	7,981,862 MCF	1.00	7,981,862	38,825,246	3.16
9	DEBARY	1-10	785	431	0.2	79 97	8.8	13,201	GAS	5,693 MCF	1.00	5,693	27,692	6.42
10	H NES CC	1-4	2,204	315,943	19.3	87.75	87.4	7,078	GAS	2,236,206 MCF	1.00	2,236,206	10,877,319	3.44
11	INT CITY	1-14	1,186	1,274	0.3	92 81	6.5	13,277	GAS	16,914 MCF	1.00	16,914	82,269	6.46
12	OSPREY	1	505	7,462	2.0	94 82	77.8	8,240	GAS	61,488 MCF	1.00	61,488	299,090	4 01
13	SUWANNEE CT	1-3	200	1,264	1.0	80.48	21.4	14,442	GAS	18,261 MCF	1.00	18,261	88,823	7 02
14	TIGER BAY	1	225	0	0.0	92 26	0.0	0	GAS	0 MCF		0	0	0 00
15	UNIV OF FLA.	1	47	30,238	86.5	94 52	91.5	9,385	GAS	283,781 MCF	1.00	283,781	1,408,742	4 66
16	AVON PARK	1-2	69	0	0.0	0 00	0.0	0	LIGHT OIL	0 BBLS		0	0	0 00
17	BARTOW	1-4	228	230	0.2	87.18	15.4	15,208	LIGHT OIL	601 BBLS	5.83	3,503	67,111	29.13
18	BARTOW CC	1	1,279	0	67.1	95.16	70.5	0	LIGHT OIL	0 BBLS	5.83	0	0	0 00
19	BAYBORO	1-4	231	220	0.1	92 58	23.9	13,262	LIGHT OIL	501 BBLS	5.83	2,923	74,765	33 92
20	DEBARY	1-10	785	957	0.2	79 97	8.8	12,959	LIGHT OIL	2,127 BBLS	5.83	12,400	261,210	27 30
21	H NES CC	1-4	2,204	878	19.3	87.75	87.4	7,293	LIGHT OIL	1,099 BBLS	5.83	6,400	97,183	11 07
22	OTHER		0	0	0.0	0 00	0.0	0	LIGHT OIL	0 BBLS	5.83	0	0	0 00
23	INT CITY	1-14	1,186	1,727	0.3	92 81	6.5	12,895	LIGHT OIL	3,824 BBLS	5.83	22,273	405,519	23.48
24	SUWANNEE CT	1-3	200	149	1.0	80.48	21.4	13,900	LIGHT OIL	356 BBLS	5.83	2,075	35,608	23 85
25	OTHER - START UP	0	-	0	-	0 00	0.0	0	LIGHT OIL	1,211 BBLS	5.83	7,055	182,782	0 00
26	SOLAR	1	438	51,234	15.7	0 00	34.3	0	SOLAR	0 N/A		0	0	0 00
27	TOTAL			2,937,259								21,819,956	97,148,448	3 31

Duke Energy Florida, LLC
Inventory Analysis
Estimated for the Period of : January 2020 through December 2020

			Act Jan-20	Act Feb-20	Act Mar-20	Act Apr-20	Act May-20	Act Jun-20	Subtotal
	LIGHT OIL								
1	PURCHASES:								
2	UNITS	BBL	4,851	0	3,896	2,140	8,349	1,599	20,835
3	UNIT COST	$/BBL	0.00	0.00	57.94	150.64	153.72	151.13	99.51
4	AMOUNT	$	0	0	225,723	322,372	1,283,431	241,662	2,073,188
5	BURNED:								
6	UNITS	BBL	1,792	4,616	5,425	4,760	10,138	12,892	39,623
7	UNIT COST	$/BBL	113.35	109.27	108.07	112.16	130.14	116.19	117.23
8	AMOUNT	$	203,121	504,375	586,296	533,872	1,319,347	1,497,965	4,644,976
9	ENDING INVENTORY:								
10	UNITS	BBL	608,678	604,058	602,529	600,002	598,121	586,874	
11	UNIT COST	$/BBL	108.37	108.36	108.04	108.14	108.42	108.36	
12	AMOUNT	$	65,960,881	65,456,505	65,095,932	64,884,431	64,848,515	63,592,212	
	COAL								
13	PURCHASES:								
14	UNITS	TON	92,942	1,185	66,506	111,462	139,943	133,432	545,470
15	UNIT COST	$/TON	100.24	821.51	128.27	106.98	74.04	75.90	93.93
16	AMOUNT	$	9,316,292	973,492	8,530,672	11,924,695	10,361,470	10,127,697	51,234,317
17	BURNED:								
18	UNITS	TON	0	0	17,493	61,653	140,193	143,523	362,862
19	UNIT COST	$/TON	-	-	89.03	92.41	88.58	86.03	88.24
20	AMOUNT	$	0	0	1,557,446	5,697,251	12,417,961	12,347,466	32,020,124
21	ENDING INVENTORY:								
22	UNITS	TON	431,062	432,247.00	481,260	531,069	530,819	520,729	
23	UNIT COST	$/TON	80.97	83.00	89.03	92.41	88.58	86.03	
24	AMOUNT	$	34,901,041	35,874,533	42,847,758	49,075,203	47,018,712	44,798,943	
	GAS								
25	BURNED:								
26	UNITS	MCF	19,744,076	18,695,068	22,283,497	20,472,403	21,849,351	25,649,038	128,693,433
27	UNIT COST	$/MCF	3.79	3.49	3.19	3.14	3.36	2.96	3.30
28	AMOUNT	$	74,789,181	65,213,448	71,149,285	64,183,893	73,391,199	75,863,000	424,590,006

Duke Energy Florida, LLC
Inventory Analysis
Estimated for the Period of : January 2020 through December 2020

			Est Jul-20	Est Aug-20	Est Sep-20	Est Oct-20	Est Nov-20	Est Dec-20	Total
	LIGHT OIL								
1	PURCHASES:								
2	UNITS	BBL	7,977	7,738	8,638	7,906	6,503	9,719	69,316
3	UNIT COST	$/BBL	116.86	118.11	117.09	120.23	117.28	115.67	112.07
4	AMOUNT	$	932,159	913,933	1,011,462	950,529	762,685	1,124,178	7,768,134
5	BURNED:								
6	UNITS	BBL	7,977	7,738	8,638	7,906	6,503	9,719	88,104
7	UNIT COST	$/BBL	116.86	118.11	117.09	120.23	117.28	115.67	117.36
8	AMOUNT	$	932,159	913,933	1,011,462	950,529	762,685	1,124,178	10,339,922
9	ENDING INVENTORY:								
10	UNITS	BBL	586,874	586,874	586,874	586,874	586,874	586,874	
11	UNIT COST	$/BBL	108.36	108.36	108.36	108.36	108.36	108.36	
12	AMOUNT	$	63,592,212	63,592,212	63,592,212	63,592,212	63,592,212	63,592,212	
	COAL								
13	PURCHASES:								
14	UNITS	TON	79,360	181,845	158,106	182,641	219,903	275,067	1,642,392
15	UNIT COST	$/TON	102.24	89.70	90.38	88.21	85.90	80.25	89.52
16	AMOUNT	$	8,114,040	16,311,312	14,289,480	16,111,023	18,889,783	22,074,322	147,024,277
17	BURNED:								
18	UNITS	TON	79,360	181,845	158,106	182,641	219,903	275,067	1,459,784
19	UNIT COST	$/TON	102.24	89.70	90.38	88.21	85.90	80.25	87.55
20	AMOUNT	$	8,114,040	16,311,312	14,289,480	16,111,023	18,889,783	22,074,322	127,810,084
21	ENDING INVENTORY:								
22	UNITS	TON	520,729	520,729	520,729	520,729	520,729	520,729	
23	UNIT COST	$/TON	86.03	86.03	86.03	86.03	86.03	86.03	
24	AMOUNT	$	44,798,943	44,798,943	44,798,943	44,798,943	44,798,943	44,798,943	
	GAS								
25	BURNED:								
26	UNITS	MCF	28,506,746	27,948,367	26,147,693	22,397,111	15,715,665	15,197,117	264,606,132
27	UNIT COST	$/MCF	2.88	3.03	3.10	3.29	4.22	4.87	3.35
28	AMOUNT	$	82,224,375	84,776,628	81,104,077	73,772,397	66,322,269	73,949,948	886,739,700

Duke Energy Florida, LLC
Fuel Cost of Power Sold
Estimated for the Period of : January 2020 through December 2020

(1)	(2)	(3)	(4)	(5)	(6)	(7)		(8)	(9)	(10)
MONTH	SOLD TO	TYPE & SCHED	TOTAL MWH SOLD	MWH WHEELED FROM OTHER SYSTEMS	MWH FROM OWN GENERATION	C/KWH (A) FUEL COST	C/KWH (B) TOTAL COST	TOTAL $ FOR FUEL ADJ (6) x (7)(A)	TOTAL COST $ (6) x (7)(B)	REFUNDABLE GAIN ON POWER SALES $
Jan-20	ECONSALE	--	4,455		4,455	1.460	1.774	65,028	79,025	13,997
Act	ECONOMY	C	0		0	0.000	0.000	0	0	0
	EXCESS GAIN	--	0		0	0.000	0.000	0	0	0
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	STRATIFIED	--	51,399		51,399	1.998	1.998	1,026,793	1,026,793	0
	TOTAL		55,854		55,854	1.955	1.980	1,091,821	1,105,818	13,997
Feb-20	ECONSALE	--	4,431		4,431	1.855	2.480	82,184	109,870	27,685
Act	ECONOMY	C	0		0	0.000	0.000	0	0	0
	EXCESS GAIN	--	0		0	0.000	0.000	0	0	0
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	STRATIFIED	--	54,588		54,588	1.924	1.924	1,050,002	1,050,002	0
	TOTAL		59,019		59,019	1.918	1.965	1,132,186	1,159,871	27,685
Mar-20	ECONSALE	--	3,970		3,970	1.176	1.654	46,687	65,647	18,959
Act	ECONOMY	C	0		0	0.000	0.000	0	0	0
	EXCESS GAIN	--	0		0	0.000	0.000	0	0	0
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	STRATIFIED	--	136,447		136,447	0.914	0.914	1,246,506	1,246,506	0
	TOTAL		140,417		140,417	0.921	0.934	1,293,193	1,312,152	18,959
Apr-20	ECONSALE	--	5,730		5,730	1.492	2.233	85,510	127,974	42,464
Act	ECONOMY	C	0		0	0.000	0.000	0	0	0
	EXCESS GAIN	--	0		0	0.000	0.000	0	0	0
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	STRATIFIED	--	130,657		130,657	1.901	1.901	2,484,344	2,484,344	0
	TOTAL		136,387		136,387	1.884	1.915	2,569,854	2,612,318	42,464
May-20	ECONSALE	--	2,375		2,375	2.711	3.286	64,389	78,032	13,643
Act	ECONOMY	C	0		0	0.000	0.000	0	0	0
	EXCESS GAIN	--	0		0	0.000	0.000	0	0	0
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	STRATIFIED	--	256,476		256,476	2.112	2.112	5,417,069	5,417,069	0
	TOTAL		258,851		258,851	2.118	2.123	5,481,458	5,495,100	13,643
Jun-20	ECONSALE	--	9,565		9,565	2.215	3.902	211,899	373,210	161,310
Act	ECONOMY	C	0		0	0.000	0.000	0	0	0
	EXCESS GAIN	--	0		0	0.000	0.000	0	0	0
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	STRATIFIED	--	300,281		300,281	2.076	2.076	6,232,898	6,232,898	0
	TOTAL		309,846		309,846	2.080	2.132	6,444,797	6,606,107	161,310
Jan-20	ECONSALE	--	30,526		30,526	1.820	2.731	555,698	833,756	278,059
THRU	ECONOMY	C	0		0	0.000	0.000	0	0	0
Jun-20	EXCESS GAIN	--	0		0	0.000	0.000	0	0	0
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	STRATIFIED	--	929,848		929,848	1.877	1.877	17,457,611	17,457,611	0
	TOTAL		960,374		960,374	1.876	1.905	18,013,308	18,291,367	278,059

Duke Energy Florida, LLC
Fuel Cost of Power Sold
Estimated for the Period of : January 2020 through December 2020

(1) MONTH	(2) SOLD TO	(3) TYPE & SCHED	(4) TOTAL MWH SOLD	(5) MWH WHEELED FROM OTHER SYSTEMS	(6) MWH FROM OWN GENERATION	(7) C/KWH (A) FUEL COST	(7) C/KWH (B) TOTAL COST	(8) TOTAL $ FOR FUEL ADJ (6) x (7)(A)	(9) TOTAL COST $ (6) x (7)(B)	(10) REFUNDABLE GAIN ON POWER SALES $
Jul-20	ECONSALE	--	21,129		21,129	3.157	3.957	666,950	836,069	169,119
Est	ECONOMY	C	0		0	0.000	0.000	0	0	0
	EXCESS GAIN	--	0		0	0.000	0.000	0	0	0
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	STRATIFIED	--	373,751		373,751	1.759	1.759	6,572,998	6,572,998	0
	TOTAL		394,880		394,880	1.833	1.876	7,239,948	7,409,067	169,119
Aug-20	ECONSALE	--	23,481		23,481	3.806	4.771	893,645	1,120,246	226,601
Est	ECONOMY	C	0		0	0.000	0.000	0	0	0
	EXCESS GAIN	--	0		0	0.000	0.000	0	0	0
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	STRATIFIED	--	375,509		375,509	1.838	1.838	6,901,444	6,901,444	0
	TOTAL		398,990		398,990	1.954	2.011	7,795,089	8,021,690	226,601
Sep-20	ECONSALE	--	19,901		19,901	3.221	4.037	640,967	803,497	162,530
Est	ECONOMY	C	0		0	0.000	0.000	0	0	0
	EXCESS GAIN	--	0		0	0.000	0.000	0	0	0
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	STRATIFIED	--	382,445		382,445	1.874	1.874	7,168,213	7,168,213	0
	TOTAL		402,346		402,346	1.941	1.981	7,809,180	7,971,710	162,530
Oct-20	ECONSALE	--	8,219		8,219	3.146	3.944	258,600	324,174	65,574
Est	ECONOMY	C	0		0	0.000	0.000	0	0	0
	EXCESS GAIN	--	0		0	0.000	0.000	0	0	0
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	STRATIFIED	--	370,015		370,015	1.960	1.960	7,253,825	7,253,825	0
	TOTAL		378,234		378,234	1.986	2.004	7,512,425	7,577,999	65,574
Nov-20	ECONSALE	--	7,878		7,878	3.420	4.287	269,399	337,711	68,312
Est	ECONOMY	C	0		0	0.000	0.000	0	0	0
	EXCESS GAIN	--	0		0	0.000	0.000	0	0	0
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	STRATIFIED	--	118,484		118,484	1.823	1.823	2,159,728	2,159,728	0
	TOTAL		126,361		126,361	1.922	1.976	2,429,127	2,497,439	68,312
Dec-20	ECONSALE	--	21,425		21,425	2.915	3.654	624,551	782,919	158,368
Est	ECONOMY	C	0		0	0.000	0.000	0	0	0
	EXCESS GAIN	--	0		0	0.000	0.000	0	0	0
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	STRATIFIED	--	76,552		76,552	2.173	2.173	1,663,203	1,663,203	0
	TOTAL		97,977		97,977	2.335	2.497	2,287,754	2,446,122	158,368
Jan-20	ECONSALE	--	132,558		132,558	2.950	3.801	3,909,810	5,038,372	1,128,563
THRU	ECONOMY	C	0		0	0.000	0.000	0	0	0
Dec-20	EXCESS GAIN	--	0		0	0.000	0.000	0	0	0
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	STRATIFIED	--	2,626,604		2,626,604	1.872	1.872	49,177,021	49,177,021	0
	TOTAL		2,759,161		2,759,161	1.924	1.965	53,086,830	54,215,393	1,128,563

Duke Energy Florida, LLC
Purchased Power
(Exclusive of Economy & QF Purchases)
Estimated for the Period of : January 2020 through December 2020

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)		(9)
				MWH			C/KWH		TOTAL $
MONTH	NAME OF PURCHASE	TYPE & SCHEDULE	TOTAL MWH PURCHASED	FOR OTHER UTILITIES	MWH FOR INTERRUPTIBLE	MWH FOR FIRM	(A) FUEL COST	(B) TOTAL COST	FOR FUEL ADJ (7) x (8)(B)
Jan-20	OTHER	--	0			0	0.000	0.000	0
Act	SHADY HILLS	--	1,286			1,286	8.385	8.385	107,833
	SOCO Franklin	--	51,560			51,560	2.892	2.892	1,491,174
	Vandolah (NSG)	--	2,545			2,545	6.999	6.999	178,125
	TOTAL		55,391	0	0	55,391	3.208	3.208	1,777,132
Feb-20	OTHER	--	0			0	0.000	0.000	0
Act	SHADY HILLS	--	1,846			1,846	6.738	6.738	124,387
	SOCO Franklin	--	45,564			45,564	3.977	3.977	1,812,026
	Vandolah (NSG)	--	24,877			24,877	4.829	4.829	1,201,222
	TOTAL		72,287	0	0	72,287	4.341	4.341	3,137,635
Mar-20	OTHER	--	0			0	0.000	0.000	0
Act	SHADY HILLS	--	39,319			39,319	7.381	7.381	2,901,972
	SOCO Franklin	--	91,038			91,038	3.517	3.517	3,201,693
	Vandolah (NSG)	--	(107)			(107)	-64.827	-64.827	69,364
	TOTAL		130,250	0	0	130,250	4.739	4.739	6,173,029
Apr-20	OTHER	--	0			0	0.000	0.000	0
Act	SHADY HILLS	--	24,795			24,795	0.372	0.372	92,246
	SOCO Franklin	--	62,902			62,902	2.308	2.308	1,452,061
	Vandolah (NSG)	--	5,689			5,689	6.566	6.566	373,552
	TOTAL		93,386	0	0	93,386	2.054	2.054	1,917,858
May-20	OTHER	--	0			0	0.000	0.000	0
Act	SHADY HILLS	--	2,667			2,667	5.614	5.614	149,733
	SOCO Franklin	--	127,571			127,571	2.712	2.712	3,459,209
	Vandolah (NSG)	--	58,078			58,078	4.882	4.882	2,835,476
	TOTAL		188,316	0	0	188,316	3.422	3.422	6,444,417
Jun-20	OTHER	--	0			0	0.000	0.000	0
Act	SHADY HILLS	--	37,822			37,822	4.533	4.533	1,714,616
	SOCO Franklin	--	127,939			127,939	3.137	3.137	4,013,506
	Vandolah (NSG)	--	98,010			98,010	4.152	4.152	4,069,754
	TOTAL		263,771	0	0	263,771	3.715	3.715	9,797,876
Jan-20	OTHER	--	0			0	0.000	0.000	0
THRU	SHADY HILLS	--	107,735			107,735	4.725	4.725	5,090,787
Jun-20	SOCO Franklin	--	506,574			506,574	3.046	3.046	15,429,668
	Vandolah (NSG)	--	189,092			189,092	4.615	4.615	8,727,493
	TOTAL		803,401	0	0	803,401	3.641	3.641	29,247,948

Duke Energy Florida, LLC
Purchased Power
(Exclusive of Economy & QF Purchases)
Estimated for the Period of : January 2020 through December 2020

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)		(9)
				MWH			C/KWH		TOTAL $
MONTH	NAME OF PURCHASE	TYPE & SCHEDULE	TOTAL MWH PURCHASED	FOR OTHER UTILITIES	MWH FOR INTERRUPTIBLE	MWH FOR FIRM	(A) FUEL COST	(B) TOTAL COST	FOR FUEL ADJ (7) x (8)(B)
Jul-20	OTHER	--	0			0	0.000	0.000	0
Est	SHADY HILLS	--	112,175			112,175	3.119	3.119	3,498,297
	SOCO Franklin	--	160,847			160,847	2.057	2.057	3,308,569
	Vandolah (NSG)	--	50,713			50,713	3.405	3.405	1,726,518
	TOTAL		323,734	0	0	323,734	2.636	2.636	8,533,384
Aug-20	OTHER	--	0			0	0.000	0.000	0
Est	SHADY HILLS	--	26,010			26,010	3.343	3.343	869,545
	SOCO Franklin	--	131,817			131,817	2.128	2.128	2,805,204
	Vandolah (NSG)	--	24,206			24,206	3.722	3.722	901,019
	TOTAL		182,033	0	0	182,033	2.514	2.514	4,575,768
Sep-20	OTHER	--	0			0	0.000	0.000	0
Est	SHADY HILLS	--	19,646			19,646	3.420	3.420	671,894
	SOCO Franklin	--	105,594			105,594	2.180	2.180	2,301,862
	Vandolah (NSG)	--	18,535			18,535	3.902	3.902	723,150
	TOTAL		143,775	0	0	143,775	2.571	2.571	3,696,906
Oct-20	OTHER	--	0			0	0.000	0.000	0
Est	SHADY HILLS	--	34,267			34,267	3.590	3.590	1,230,029
	SOCO Franklin	--	112,417			112,417	2.219	2.219	2,494,987
	Vandolah (NSG)	--	15,690			15,690	4.038	4.038	633,577
	TOTAL		162,374	0	0	162,374	2.684	2.684	4,358,593
Nov-20	OTHER	--	0			0	0.000	0.000	0
Est	SHADY HILLS	--	3,545			3,545	10.327	10.327	366,067
	SOCO Franklin	--	0			0	0.000	0.000	0
	Vandolah (NSG)	--	8,313			8,313	8.654	8.654	719,471
	TOTAL		11,858	0	0	11,858	9.154	9.154	1,085,538
Dec-20	OTHER	--	0			0	0.000	0.000	0
Est	SHADY HILLS	--	0			0	0.000	0.000	3,594
	SOCO Franklin	--	3,122			3,122	3.319	3.319	103,621
	Vandolah (NSG)	--	367			367	18.324	18.324	67,269
	TOTAL		3,489	0	0	3,489	5.001	5.001	174,484
Jan-20	OTHER	--	0			0	0.000	0.000	-
THRU	SHADY HILLS	--	303,377			303,377	3.867	3.867	11,730,213
Dec-20	SOCO Franklin	--	1,020,371			1,020,371	2.592	2.592	26,443,911
	Vandolah (NSG)	--	306,915			306,915	4.398	4.398	13,498,497
TOTAL			1,630,664	0	0	1,630,664	3.169	3.169	51,672,621

Duke Energy Florida, LLC
Energy Payments to Qualifying Facilities
Estimated for the Period of : January 2020 through December 2020

(1) MONTH	(2) NAME OF PURCHASE	(3) TYPE & SCHEDULE	(4) TOTAL MWH PURCHASED	(5) MWH FOR OTHER UTILITIES	(6) MWH FOR INTERRUPTIBLE	(7) MWH FOR FIRM	(8) C/KWH (A) ENERGY COST	(B) TOTAL COST	(9) TOTAL $ FOR FUEL ADJ (7) x (8)(A)
Jan-20 Act	QUAL. FACILITIES	COGEN	217,861			217,861	3.360	15.822	7,319,413
Feb-20 Act	QUAL. FACILITIES	COGEN	207,861			207,861	3.412	3.412	7,093,012
Mar-20 Act	QUAL. FACILITIES	COGEN	176,228			176,228	3.150	3.150	5,551,577
Apr-20 Act	QUAL. FACILITIES	COGEN	169,832			169,832	3.186	3.186	5,410,902
May-20 Act	QUAL. FACILITIES	COGEN	215,806			215,806	3.484	3.484	7,518,681
Jun-20 Act	QUAL. FACILITIES	COGEN	220,435			220,435	3.370	3.370	7,427,850
Jul-20 Est	QUAL. FACILITIES	COGEN	233,845			233,845	3.595	15.209	8,407,595
Aug-20 Est	QUAL. FACILITIES	COGEN	233,845			233,845	3.597	15.210	8,411,122
Sep-20 Est	QUAL. FACILITIES	COGEN	220,885			220,885	3.599	15.894	7,949,571
Oct-20 Est	QUAL. FACILITIES	COGEN	198,259			198,259	3.577	17.275	7,091,011
Nov-20 Est	QUAL. FACILITIES	COGEN	222,188			222,188	3.702	15.925	8,225,712
Dec-20 Est	QUAL. FACILITIES	COGEN	251,175			251,175	3.596	14.408	9,032,312
TOTAL	QUAL. FACILITIES	COGEN	2,568,222			2,568,222	3.483	10.884	89,438,758

Duke Energy Florida, LLC
Economy Energy Purchases
Estimated for the Period of : January 2020 through December 2020

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)		(9)
				TRANSACTION COST		TOTAL $	COST IF GENERATED		
MONTH	PURCHASE	TYPE & SCHED	TOTAL MWH PURCHASED	ENERGY COST C/KWH	TOTAL COST C/KWH	FOR FUEL ADJ (4) x (5)	(A) C/KWH	(B) $	FUEL SAVINGS (8)(B) - (7)
Jan-20	ECONPURCH	--	4,764	3.017	3.017	143,759	3.831	182,504	38,745
Act	SEPA	--	0	0.000	0.000	0	0.000	0	0
	TOTAL		4,764	3.017	3.017	143,759	3.831	182,504	38,745
Feb-20	ECONPURCH	--	15,915	2.554	2.554	406,521	3.113	495,461	88,940
Act	SEPA	--	0	0.000	0.000	0	0.000	0	-
	TOTAL		15,915	2.554	2.554	406,521	3.113	495,461	88,940
Mar-20	ECONPURCH	--	32,840	3.208	3.208	1,053,448	4.033	1,324,346	270,898
Act	SEPA	--	0	0.000	0.000	0	0.000	0	-
	TOTAL		32,840	3.208	3.208	1,053,448	4.033	1,324,346	270,898
Apr-20	ECONPURCH	--	16,089	3.017	3.017	485,384	4.736	761,909	276,525
Act	SEPA	--	0	0.000	0.000	0	0.000	0	-
	TOTAL		16,089	3.017	3.017	485,384	4.736	761,909	276,525
May-20	ECONPURCH	--	13,029	3.129	3.129	407,645	3.298	429,709	22,064
Act	SEPA	--	0	0.000	0.000	0	0.000	0	-
	TOTAL		13,029	3.129	3.129	407,645	3.298	429,709	22,064
Jun-20	ECONPURCH	--	7,127	2.651	2.651	188,921	2.875	204,891	15,970
Act	SEPA	--	0	0.000	0.000	0	0.000	0	-
	TOTAL		7,127	2.651	2.651	188,921	2.875	204,891	15,970
Jan-20	ECONPURCH	--	89,764	2.992	2.992	2,685,678	3.786	3,398,821	713,142
THRU	SEPA	--	0	0.000	0.000	0	0.000	0	0
Jun-20									
	TOTAL		89,764	2.992	2.992	2,685,678	3.786	3,398,821	713,142

Duke Energy Florida, LLC
Economy Energy Purchases
Estimated for the Period of : January 2020 through December 2020

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)		(9)
				TRANSACTION COST		TOTAL $	COST IF GENERATED		
MONTH	PURCHASE	TYPE & SCHED	TOTAL MWH PURCHASED	ENERGY COST C/KWH	TOTAL COST C/KWH	FOR FUEL ADJ (4) x (5)	(A) C/KWH	(B) $	FUEL SAVINGS (8)(B) - (7)
Jul-20	ECONPURCH	--	4,573	3.890	3.890	177,886	4.365	199,578	21,692
Est	SEPA	--	0	0.000	0.000	0	0.000	0	-
	TOTAL		4,573	3.890	3.890	177,886	4.365	199,578	21,692
Aug-20	ECONPURCH	--	2,728	4.166	4.166	113,649	4.674	127,498	13,849
Est	SEPA	--	0	0.000	0.000	0	0.000	0	-
	TOTAL		2,728	4.166	4.166	113,649	4.674	127,498	13,849
Sep-20	ECONPURCH	--	4,275	4.165	4.165	178,038	4.673	199,744	21,706
Est	SEPA	--	0	0.000	0.000	0	0.000	0	-
	TOTAL		4,275	4.165	4.165	178,038	4.673	199,744	21,706
Oct-20	ECONPURCH	--	3,276	3.926	3.926	128,590	4.404	144,270	15,680
Est	SEPA	--	0	0.000	0.000	0	0.000	0	-
	TOTAL		3,276	3.926	3.926	128,590	4.404	144,270	15,680
Nov-20	ECONPURCH	--	2,479	3.682	3.682	91,292	4.131	102,420	11,128
Est	SEPA	--	0	0.000	0.000	0	0.000	0	-
	TOTAL		2,479	3.682	3.682	91,292	4.131	102,420	11,128
Dec-20	ECONPURCH	--	3,278	3.825	3.825	125,383	4.291	140,677	15,294
Est	SEPA	--	0	0.000	0.000	0	0.000	0	-
	TOTAL		3,278	3.825	3.825	125,383	4.291	140,677	15,294
Jan-20	ECONPURCH	--	110,373	3.172	3.172	3,500,516	3.908	4,313,008	812,491
THRU	SEPA	--	0	0.000	0.000	0	0.000	0	0
Dec-20									
	TOTAL		110,373	3.172	3.172	3,500,516	3.908	4,313,008	812,491

Duke Energy Florida, LLC
Capital Structure and Cost Rates Applied to Capital Projects
Estimated for the Period of : January 2020 through June 2020

	Adjusted Retail $000's	Ratio	Cost Rate	Weighted Cost	PreTax Weighted Cost Rate
Common Equity	$ 4,874,577	41.01%	10.50%	4.31%	5.71%
Long Term Debt	4,845,025	40.77%	4.70%	1.92%	1.92%
Short Term Debt	(59,427)	-0.50%	-0.36%	0.00%	0.00%
Customer Deposits - Active	176,757	1.49%	2.38%	0.04%	0.04%
Customer Deposits - Inactive	1,853	0.02%	0.00%	0.00%	0.00%
Deferred Tax	2,026,313	17.05%	0.00%	0.00%	0.00%
ITC	19,806	0.17%	7.71%	0.01%	0.01%
	11,884,905	0.09%		6.27%	7.67%
			Total Debt	1.97%	1.97%
			Total Equity	4.31%	5.71%

Note> May 2019 DEF Surveillance Report capital structure and cost rates. See Amended Unopposed Joint Motion to Modify Order No. PSC-2012-0425-PAA-EU Regarding Weighted Average Cost of Capital Methodology approved May 20, 2020 in Docket No. 20200118-EU, Order No. PSC-2020-0165-PAA-EU.

Duke Energy Florida, LLC
Capital Structure and Cost Rates Applied to Capital Projects
Estimated for the Period of : July 2020 through December 2020

	Adjusted Retail $000's	Ratio	Cost Rate	Weighted Cost	PreTax Weighted Cost Rate
Common Equity	$ 5,587,139,333	41.48%	10.50%	4.36%	5.77%
Long Term Debt	5,219,534,862	38.75%	4.62%	1.79%	1.79%
Short Term Debt	228,721,050	1.70%	2.10%	0.04%	0.04%
Customer Deposits - Active	184,176,907	1.37%	2.43%	0.03%	0.03%
Customer Deposits - Inactive	1,820,718	0.01%	0.00%	0.00%	0.00%
Deferred Tax	2,189,708,749	16.26%	0.00%	0.00%	0.00%
ITC	58,310,573	0.43%	7.66%	0.03%	0.03%
	$ 13,469,412,193	100.00%		6.25%	7.66%
			Total Debt	1.89%	1.89%
			Total Equity	4.36%	5.77%

Note> May 2020 DEF Surveillance Report capital structure and cost rates. See Amended Unopposed Joint Motion to Modify Order No. PSC-2012-0425-PAA-EU Regarding Weighted Average Cost of Capital Methodology approved May 20, 2020 in Docket No. 20200118-EU, Order No. PSC-2020-0165-PAA-EU.

Docket No. 20200001-EI
Exhibit No. ____(CAM-2)
Part 2

DUKE ENERGY FLORIDA, LLC

Capacity Cost Recovery

Actual / Estimated True-Up

January through December 2020

Schedule E12-A – Purchased Power Capacity Cost (Projected)

Schedule E12-B – Purchased Power Capacity Cost (Re-Projected)

Schedule E12-C – Variance Analysis (Re-projected vs. Projected)

Duke Energy Florida, LLC
Calculation of Projected Capacity Costs
For the Year 2020

Docket No. 20200001-EI
Exhibit__CAM-2, Part 2
Schedule E12-A

		EST Jan-20	EST Feb-20	EST Mar-20	EST Apr-20	EST May-20	EST Jun-20	EST Jul-20	EST Aug-20	EST Sep-20	EST Oct-20	EST Nov-20	EST Dec-20	TOTAL
1	**Base Production Level Capacity Costs**													
2	Orange Cogen (ORANGECO)	5,887,169	5,887,169	5,887,169	5,887,169	5,887,169	5,887,169	5,887,169	5,887,169	5,887,169	5,887,169	5,887,169	5,887,169	70,646,029
3	Orlando Cogen Limited (ORLACOGL)	5,923,355	5,923,355	5,923,355	5,923,355	5,923,355	5,923,355	5,923,355	5,923,355	5,923,355	5,923,355	5,923,355	5,923,355	71,080,257
4	Pasco County Resource Recovery (PASCOUNT)	2,147,740	2,147,740	2,147,740	2,147,740	2,147,740	2,147,740	2,147,740	2,147,740	2,147,740	2,147,740	2,147,740	2,147,740	25,772,880
5	Pinellas County Resource Recovery (PINCOUNT)	5,112,555	5,112,555	5,112,555	5,112,555	5,112,555	5,112,555	5,112,555	5,112,555	5,112,555	5,112,555	5,112,555	5,112,555	61,350,660
6	Polk Power Partners, L.P. (MULBERRY/ROYSTER)	8,086,717	8,086,717	8,086,717	8,086,717	8,086,717	8,086,717	8,086,717	8,086,717	8,086,717	8,086,717	8,086,717	8,086,717	97,040,598
7	Subtotal - Base Level Capacity Costs	27,157,535	27,157,535	27,157,535	27,157,535	27,157,535	27,157,535	27,157,535	27,157,535	27,157,535	27,157,535	27,157,535	27,157,535	325,890,424
8	Base Production Jurisdictional Responsibility	92.885%	92.885%	92.885%	92.885%	92.885%	92.885%	92.885%	92.885%	92.885%	92.885%	92.885%	92.885%	
9	Base Level Jurisdictional Capacity Costs	25,225,277	25,225,276	25,225,276	25,225,276	25,225,276	25,225,277	25,225,277	25,225,277	25,225,277	25,225,277	25,225,277	25,225,277	302,703,317
10	**Intermediate Production Level Capacity Costs**													
11	Southern Franklin	4,803,596	4,803,596	2,834,972	2,834,972	3,116,204	5,366,060	6,490,988	6,490,988	4,803,596	2,834,972	2,834,972	3,678,668	50,893,581
12	Schedule H Capacity Sales	-	-	-	-	-	-	-	-	-	-	-	-	-
13	Subtotal - Intermediate Level Capacity Costs	4,803,596	4,803,596	2,834,972	2,834,972	3,116,204	5,366,060	6,490,988	6,490,988	4,803,596	2,834,972	2,834,972	3,678,668	50,893,581
14	Intermediate Production Jurisdict. Responsibility	72.703%	72.703%	72.703%	72.703%	72.703%	72.703%	72.703%	72.703%	72.703%	72.703%	72.703%	72.703%	
15	Intermediate Level Jurisdict. Capacity Costs	3,492,358	3,492,358	2,061,110	2,061,110	2,265,575	3,901,286	4,719,143	4,719,143	3,492,358	2,061,110	2,061,110	2,674,502	37,001,161
16	**Peaking Production Level Capacity Costs**													
17	Shady Hills	1,978,175	1,978,175	1,412,982	1,370,803	1,919,125	3,901,517	3,901,517	3,901,517	1,820,708	1,370,803	1,370,803	1,978,175	26,904,299
18	Vandolah (NSG)	2,770,874	2,786,429	1,997,185	1,974,963	2,693,097	5,552,672	5,536,005	5,491,562	2,628,284	1,936,075	1,980,519	2,786,429	38,134,092
19	Other	-	-	-	-	-	-	-	-	-	-	-	-	-
20	Subtotal - Peaking Level Capacity Costs	4,749,048	4,764,603	3,410,167	3,345,766	4,612,222	9,454,189	9,437,522	9,393,079	4,448,992	3,306,878	3,351,322	4,764,603	65,038,391
21	Peaking Production Jurisdictional Responsibility	95.924%	95.924%	95.924%	95.924%	95.924%	95.924%	95.924%	95.924%	95.924%	95.924%	95.924%	95.924%	
22	Peaking Level Jurisdictional Capacity Costs	4,555,477	4,570,398	3,271,168	3,209,393	4,424,228	9,068,836	9,052,849	9,010,217	4,267,651	3,172,090	3,214,722	4,570,398	62,387,427
23	**Other Capacity Costs**													
24	Retail Wheeling	(49,081)	(26,693)	(6,391)	(8,251)	(22,290)	(26,580)	(30,641)	(32,297)	(17,960)	(15,271)	(8,249)	(27,392)	(271,098)
25	Ridge Generating Station L.P. Termination [1]	709,446	705,945	702,444	698,943	695,442	691,941	688,439	684,938	681,437	677,936	674,435	670,934	8,282,280
26	SoBRA True-Up - Hamilton [2]	(478,334)								-				(478,334)
27	Total Other Capacity Costs	182,032	679,252	696,053	690,691	673,152	665,360	657,798	652,641	663,477	662,665	666,186	643,541	7,532,848
28	**Total Capacity Costs (line 9+15+22+27)**	33,455,143	33,967,284	31,253,608	31,186,470	32,588,230	38,860,759	39,655,066	39,607,278	33,648,763	31,121,141	31,167,294	33,113,718	409,624,753
29	Actual/Estimated True-Up Provision - Jan - Dec 2019													(1,848,509)
30	**Total Capacity Costs w/ True-Up**													407,776,244
31	Revenue Tax Multiplier													1.00072
32	**Total Recoverable Capacity Costs**													408,069,843
33	**ISFSI Revenue Requirement** [3]													6,879,837
34	Revenue Tax Multiplier													1.00072
35	**Total Recoverable ISFSI Costs**													6,884,790
36	**Total Recoverable Capacity & ISFSI Costs (line 32+35)**													414,954,634

[1] Approved in Commission Order No. PSC-2018-0532-PAA-EQ.
[2] True-up of Hamilton Solar Project costs as filed in Docket No. 20190072 in accordance with paragraph 15g of the 2017 Settlement.
[3] Approved in Commission Order No. PSC-2016-0425-PAA-EI.

Duke Energy Florida, LLC
Calculation of Projected Capacity Costs
For the Year 2020

Docket No. 20200001-EI
Exhibit__CAM-2, Part 2
Schedule E12-B

		ACT Jan-20	ACT Feb-20	ACT Mar-20	ACT Apr-20	ACT May-20	ACT Jun-20	EST Jul-20	EST Aug-20	EST Sep-20	EST Oct-20	EST Nov-20	EST Dec-20	TOTAL
1	**Base Production Level Capacity Costs**													
2	Orange Cogen (ORANGECO)	5,880,980	5,893,358	5,887,169	5,887,169	5,887,169	5,887,169	5,887,169	5,887,169	5,887,169	5,887,169	5,887,169	5,887,169	70,646,031
3	Orlando Cogen Limited (ORLACOGL)	5,923,355	5,923,355	5,923,355	5,923,355	5,923,355	5,923,355	5,923,355	5,923,355	5,923,355	5,923,355	5,923,355	5,923,355	71,080,258
4	Pasco County Resource Recovery (PASCOUNT)	2,147,740	2,147,740	2,147,740	2,147,740	2,147,740	2,147,740	2,147,740	2,147,740	2,147,740	2,147,740	2,147,740	2,147,740	25,772,880
5	Pinellas County Resource Recovery (PINCOUNT)	5,112,555	5,112,555	5,112,555	5,112,555	5,112,555	5,112,555	5,112,555	5,112,555	5,112,555	5,112,555	5,112,555	5,112,555	61,350,660
6	Polk Power Partners, L.P. (MULBERRY/ROYSTER)	8,086,717	8,086,717	8,086,717	8,086,717	8,086,717	8,086,717	8,086,717	8,086,717	8,086,717	8,086,717	8,086,717	8,086,717	97,040,600
7	Subtotal - Base Level Capacity Costs	27,151,347	27,163,725	27,157,536	27,157,536	27,157,536	27,157,536	27,157,535	27,157,535	27,157,535	27,157,535	27,157,535	27,157,535	325,890,428
8	Base Production Jurisdictional Responsibility	92.885%	92.885%	92.885%	92.885%	92.885%	92.885%	92.885%	92.885%	92.885%	92.885%	92.885%	92.885%	
9	Base Level Jurisdictional Capacity Costs	25,219,529	25,231,025	25,225,276	25,225,276	25,225,276	25,225,277	25,225,277	25,225,277	25,225,277	25,225,277	25,225,277	25,225,277	302,703,319
10	**Intermediate Production Level Capacity Costs**													
11	Southern Franklin	4,016,449	5,550,785	2,815,069	2,816,679	1,738,090	4,096,953	6,653,118	6,653,118	4,939,686	2,940,682	2,940,682	3,797,398	48,958,709
12	Schedule H Capacity Sales	-	-	(32,469)	-	-	-	-	-	-	-	-	-	(32,469)
13	Subtotal - Intermediate Level Capacity Costs	4,016,449	5,550,785	2,782,600	2,816,679	1,738,090	4,096,953	6,653,118	6,653,118	4,939,686	2,940,682	2,940,682	3,797,398	48,926,240
14	Intermediate Production Jurisdict. Responsibility	72.703%	72.703%	72.703%	72.703%	72.703%	72.703%	72.703%	72.703%	72.703%	72.703%	72.703%	72.703%	
15	Intermediate Level Jurisdict. Capacity Costs	2,920,079	4,035,587	2,023,034	2,047,810	1,263,645	2,978,608	4,837,016	4,837,016	3,591,300	2,137,964	2,137,964	2,760,822	35,570,845
16	**Peaking Production Level Capacity Costs**													
17	Shady Hills	1,973,160	1,973,160	1,973,160	802,440	1,912,680	3,911,760	3,889,124	3,889,124	1,814,925	1,366,449	1,366,449	1,971,891	26,844,323
18	Vandolah (NSG)	2,939,299	2,876,217	1,958,481	1,943,807	2,807,348	5,839,892	5,617,529	5,572,423	2,666,444	1,963,912	2,009,019	2,826,948	39,021,320
19	Other	-	-	-	-	-	-	-	-	-	-	-	-	-
20	Subtotal - Peaking Level Capacity Costs	4,912,459	4,849,377	3,931,641	2,746,247	4,720,028	9,751,652	9,506,654	9,461,547	4,481,369	3,330,362	3,375,468	4,798,839	65,865,643
21	Peaking Production Jurisdictional Responsibility	95.924%	95.924%	95.924%	95.924%	95.924%	95.924%	95.924%	95.924%	95.924%	95.924%	95.924%	95.924%	
22	Peaking Level Jurisdictional Capacity Costs	4,712,227	4,651,717	3,771,387	2,634,310	4,527,640	9,354,175	9,119,162	9,075,895	4,298,708	3,194,616	3,237,884	4,603,238	63,180,959
23	**Other Capacity Costs**													
24	Retail Wheeling	(10,726)	(9,947)	-	(17,012)	(2,126)	(837)	(40,983)	(45,545)	(38,603)	(15,942)	(15,280)	(41,558)	(238,559)
25	Ridge Generating Station L.P. Termination [1]	708,094	704,621	701,149	697,676	694,203	690,731	687,051	683,583	680,115	676,648	673,180	669,712	8,266,764
26	State Corporate Income Tax Change [2]	-	-	(3,491,633)	(232,776)	(232,776)	(232,776)	(232,776)	(232,776)	(232,776)	(232,776)	(232,776)	(232,776)	(5,586,612)
27	Total Other Capacity Costs	697,369	694,674	(2,790,484)	447,888	459,301	457,118	413,292	405,262	408,737	427,930	425,124	395,379	2,441,593
28	**Total Capacity Costs (line 9+15+22+27)**	33,549,204	34,613,003	28,229,213	30,355,284	31,475,861	38,015,179	39,594,748	39,543,450	33,524,022	30,985,786	31,026,249	32,984,716	403,896,715
29	**ISFSI Revenue Requirement** [3]	573,320	573,320	573,320	573,320	573,320	573,320	573,320	573,320	573,320	573,320	573,320	573,320	6,879,837
30	**Total Recoverable Capacity & ISFSI Costs (line 28+29)**	34,122,523	35,186,323	28,802,534	30,928,605	32,049,181	38,588,498	40,168,068	40,116,770	34,097,342	31,559,106	31,599,569	33,558,036	410,776,553
31	**Capacity Revenues**													
32	Capacity Cost Recovery Revenues (net of tax)	27,694,435	28,661,108	29,875,620	34,161,020	32,020,716	36,912,727	41,235,583	41,983,900	40,977,417	37,057,076	29,549,322	29,176,204	409,305,128
33	Prior Period True-Up Provision Over/(Under) Recovery	154,042	154,042	154,042	154,042	154,042	154,042	154,042	154,042	154,042	154,042	154,042	154,042	1,848,509
34	**Current Period Revenues (net of tax)**	27,848,477	28,815,151	30,029,662	34,315,063	32,174,759	37,066,769	41,389,626	42,137,943	41,131,459	37,211,119	29,703,365	29,330,246	411,153,637
35	**True-Up Provision**													
36	True-Up Provision - Over/(Under) Recov (Line 34-30)	(6,274,046)	(6,371,172)	1,227,128	3,386,458	125,578	(1,521,729)	1,221,558	2,021,173	7,034,117	5,652,012	(1,896,204)	(4,227,790)	377,083
37	Interest Provision for the Month	(2,912)	(11,495)	(17,867)	(8,783)	(459)	(680)	(331)	(256)	19	239	157	(19)	(42,389)
38	Current Cycle Balance - Over/(Under)	(6,276,958)	(12,659,626)	(11,450,367)	(8,072,693)	(7,947,575)	(9,469,984)	(8,248,757)	(6,227,840)	806,295	6,458,546	4,562,499	334,694	334,694
39	Prior Period Balance - Over/(Under) Recovered	1,050,730	1,050,730	1,050,730	1,050,730	1,050,730	1,050,730	1,050,730	1,050,730	1,050,730	1,050,730	1,050,730	1,050,730	1,050,730
40	Prior Period Cumulative True-Up Collected/(Refunded)	(154,042)	(308,085)	(462,127)	(616,170)	(770,212)	(924,255)	(1,078,297)	(1,232,339)	(1,386,382)	(1,540,424)	(1,694,467)	(1,848,509)	(1,848,509)
41	Prior Period True-up Balance - Over/(Under)	896,686	742,643	588,601	434,559	280,516	126,474	(27,567)	(181,609)	(335,651)	(489,694)	(643,736)	(797,779)	(797,779)
42	**Net Capacity True-up Over/(Under) (Line 38+41)**	($5,380,272)	($11,916,982)	($10,861,764)	($7,638,133)	($7,667,056)	($9,343,508)	($8,276,324)	($6,409,449)	$470,644	$5,968,852	$3,918,763	($463,084)	($463,084)

[1] Approved in Commission Order No. PSC-2018-0532-PAA-EQ.
[2] See Third Implementation Stipulation attached as Appendix A to the Petition for the 2020 Actual/Estimated TU in Docket 20200001-EI.
[3] Approved in Commission Order No. PSC-2016-0425-PAA-EI.

Duke Energy Florida, LLC
Calculation of Projected Capacity Costs
For the Year 2020

Docket No. 20200001-EI
Exhibit__CAM-2, Part 2
Schedule E12-B

Contract Data:

	Name	Start Date	Expiration Date	Type	Purchase/Sale	MW
1	Orlando Cogen Limited (ORLACOGL)	Sep-93	Dec-23	QF	Purch	115.00
2	Orange Cogen (ORANGECO)	Jul-95	Dec-25	QF	Purch	104.00
3	Pasco County Resource Recovery (PASCOUNT)	Jan-95	Dec-24	QF	Purch	23.00
4	Pinellas County Resource Recovery (PINCOUNT)	Jan-95	Dec-24	QF	Purch	54.75
5	Polk Power Partners, L. P. (MULBERY/ROYSTER)	Aug-94	Aug-24	QF	Purch	115.00
6	Southern - Franklin	Jun-16	May-21	Other	Purch	424.00
7	Schedule H Capacity - New Smyrna Beach	Nov-85	see note (1)	Other	Sale	1.00
8	Vandolah (NSG)	Jun-12	May-27	Other	Purch	655.00
9	Shady Hills Tolling Agreement	Apr-07	Apr-24	Other	Purch	515.00

(1) The New Smyrna Beach (NSB) Schedule H contract is in effect until cancelled by either Duke Energy Florida or NSB upon 1 year's written notice.

Line		Re-Projection Total	Original Projection Total	Variance Total
1	**Capacity Revenues**			
2	Capacity Cost Recovery Revenues (net of tax)	$409,305,128	$414,656,081	($5,350,953)
3	Prior Period True-Up Provision Over/(Under) Recovery	1,848,509	1,848,509	0
4	**Current Period Revenues (net of tax)**	411,153,637	416,504,590	(5,350,953)
5				
6	**Capacity Costs**			
7	**Base Production Level Capacity Costs**			
8	Orange Cogen (ORANGECO)	70,646,031	70,646,029	2
9	Orlando Cogen Limited (ORLACOGL)	71,080,258	71,080,257	1
10	Pasco County Resource Recovery (PASCOUNT)	25,772,880	25,772,880	0
11	Pinellas County Resource Recovery (PINCOUNT)	61,350,660	61,350,660	0
12	Polk Power Partners, L.P. (MULBERRY/ROYSTER)	97,040,600	97,040,598	2
13	Subtotal - Base Level Capacity Costs	325,890,428	325,890,424	5
14	Base Production Jurisdictional Responsibility	92.885%	92.885%	0.000%
15	Base Level Jurisdictional Capacity Costs	302,703,319	302,703,317	2
16				
17	**Intermediate Production Level Capacity Costs**			
18	Southern - Franklin	48,958,709	50,893,581	(1,934,872)
19	Schedule H Capacity Sales	(32,469)	0	(32,469)
20	Subtotal - Intermediate Level Capacity Costs	48,926,240	50,893,581	(1,967,341)
21	Intermediate Production Jurisdictional Responsibility	72.703%	72.703%	0.000%
22	Intermediate Level Jurisdictional Capacity Costs	35,570,845	37,001,161	(1,430,316)
23				
24	**Peaking Production Level Capacity Costs**			
25	Shady Hills	26,844,323	26,904,299	(59,976)
26	Vandolah (NSG)	39,021,320	38,134,092	887,227
27	Subtotal - Peaking Level Capacity Costs	65,865,643	65,038,391	827,251
28	Peaking Production Jurisdictional Responsibility	95.924%	95.924%	0.000%
29	Peaking Level Jurisdictional Capacity Costs	63,180,959	62,387,427	793,533
30				
31	**Other Capacity Costs**			
32	Retail Wheeling	(238,559)	(271,098)	32,539
33	Ridge Generating Station L.P. Termination[1]	8,266,764	8,282,280	(15,516)
34	SoBRA True-Up - Hamilton[2]	0	(478,334)	478,334
35	State Corporate Income Tax Change[3]	(5,586,612)	0	(5,586,612)
36	Other Jurisdictional Capacity Costs	2,441,593	7,532,848	(5,091,255)
37				
38	**Subtotal Jurisdictional Capacity Costs (Line 15+22+29+36)**	403,896,717	409,624,753	(5,728,037)
39				
40	**ISFSI Revenue Requirement[4]**	6,879,837	6,879,837	0
41				
42	**Total Jurisdictional Capacity Costs (Line 38+40)**	410,776,553	416,504,590	(5,728,037)
43				
44	**True-Up Provision**			
45	True-Up Provision - Over/(Under) Recovered	377,083	0	377,083
46	Interest Provision for the Month	(42,389)	0	(42,389)
47	Current Cycle Balance - Over/(Under)	334,694	0	334,694
48				
49	Prior Period Balance - Over/(Under) Recovered	1,050,730	1,848,509	(797,779)
50	Prior Period Cumulative True-Up Collected/(Refunded)	(1,848,509)	(1,848,509)	0
51	Prior Period True-up Balance - Over/(Under)	(797,779)	0	(797,779)
52				
53	**Net Capacity True-up Over/(Under) (Line 47+51)**	($463,084)	$0	($463,084)

[1] Approved in Commission Order No. PSC-2018-0532-PAA-EQ.

[2] Proposed true-up of Hamilton Solar Project costs per paragraph 15g of the 2017 Settlement filed in Docket No. 20190072.-EI.

[3] See Third Implementation Stipulation attached as Appendix A to the Petition for the 2020 Actual/Estimated TU in Docket 20200001-EI.

Third Implementation Stipulation

1. The 2017 Second Revised and Restated Settlement Agreement ("Agreement") was approved by the Commission in Order No. PSC-2017-0451-AS-EU. The Commission approved the First Implementation Stipulation when it granted the Motion to Approve Implementation Stipulation by Order No. PSC-2018-0103-PCO-EI in Docket No. 20170272. The Authorization of Interim Storm Restoration Recovery Charge and Approval of the Second Implementation Stipulation was approved by the Commission in Order No. PSC-2019-0268-PCO-EI.
2. As explained more fully below, the signatories to the Agreement enter into this Third Implementation Stipulation ("Stipulation") regarding the impact of the state corporate income tax reduction authorized by the Florida legislature in 2019 and the flow of the benefits therefrom to customers in the form of a reduction to the Capacity Cost Recovery Clause ("CCR") charge.
3. Paragraph 16 of the Agreement provides a mechanism for calculating and implementing the impact of federal and state tax reform on DEF's rates, which will inure to the benefit of customers effective January 2019. On September 12, 2019, the Florida Department of Revenue issued a Tax Information Publication ("TIP") announcing that the Florida corporate income tax rate was reduced from 5.5 percent to 4.458 percent effective retroactive to January 1, 2019 and continuing in effect through December 31, 2021 ("State Tax Rate Change"). The TIP indicates that the Florida corporate income tax rate will return to 5.5 percent effective January 1, 2022.
4. The Parties agree that the impact of the State Tax Rate Change is a $2,793,306 annual reduction, for a three-year total of $8,379,919.
5. The Parties agree that the benefit of this reduction should flow back to customers through the CCR, specifically with the 2019 and 2020 amounts of $2,793,306 reflected in DEF's Actual/Estimated filing and the remaining $2,793,306 for 2021 reflected in its projection filing. Thus, the entire $8,379,919 reduction will be reflected in customers' bills starting January 1, 2021.

Duke Energy Florida, LLC

By ______________________________

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Southern Alliance for Clean Energy

By ______________________

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DUKE ENERGY FLORIDA, LLC

Fuel and Capacity Cost Recovery Factor

January through December 2021

PART 1 – 2021 FUEL PRICE FORECAST ASSUMPTIONS

Projected Market Price by Fuel Type

PROJECTED MARKET PRICE BY FUEL TYPE

	Light Oil		Coal Crystal River 4 & 5		Natural Gas
Month	**$/barrel**	**$/mmbtu**	**$/ton**	**$/mmbtu**	**$/mmbtu**
Jan 2021	48.54	8.33	69.28	2.93	2.97
Feb 2021	49.32	8.47	66.56	2.84	2.94
Mar 2021	50.08	8.60	64.22	2.75	2.83
Apr 2021	50.66	8.70	63.79	2.74	2.53
May 2021	50.96	8.75	62.73	2.70	2.49
Jun 2021	51.56	8.85	61.91	2.67	2.52
Jul 2021	52.12	8.95	61.54	2.66	2.56
Aug 2021	52.68	9.04	61.31	2.65	2.57
Sep 2021	53.27	9.14	61.23	2.65	2.55
Oct 2021	53.16	9.13	61.23	2.65	2.57
Nov 2021	52.85	9.07	61.20	2.65	2.61
Dec 2021	52.56	9.02	61.43	2.66	2.74
Average	51.48	8.84	63.04	2.71	2.66

Light Oil: The above base market oil price forecasts are the NYMEX forwards. Oil prices projected within the fuel forecast are based on expected contract structures and specifications, and incorporate transportation costs.

Coal: Coal price projections are based on independent thrid party providers and take into account current coal supply, transportation agreements and forecasted deliveries. Crystal River Units 4 and 5 have operating scrubbers that allow allow for use of higher sulfur coal.

Natural Gas: The base market natural gas proce forecast is the NYMEX Henry Hub forward. This table includes natural gas market commodity prices only; however, the fuel forecast also incorporates transportation costs. Forecast prices are based on expected contract specifications. Firm transportation costs for Florida Gas Transmission, Gulfstream and Sabal Trail pipelines are based on expected tariff rates and market conditions.

DUKE ENERGY FLORIDA, LLC

Fuel Cost Recovery

January through December 2021

PART 2 - 2021 FUEL COST RECOVERY SCHEDULES

Schedule E1 – Fuel Cost Recovery Clause Calculation

Schedule E1-A – Calculation of Total True-up

Schedule E1-B – Calculation of Prior Year Estimated True-up

Schedule E1-C – Calculation of GPIF & True-up Factors

Schedule E1-D – Calculation of Levelized Fuel Adjustment Factors

Schedule E1-E – Calculation of Factors for Metering Voltage and Time of Use

Schedule E1-F – Calculation of Jurisdictional Delivery Loss Multipliers

Schedule E2 – Fuel Cost Recovery Clause Calculation by Month

Schedule E3 – Generating System Comparative Data

Schedule E4 – System Net Generation & Fuel Cost by Month

Schedule E5 – Inventory Analysis

Schedule E6 – Fuel Cost of Power Sold

Schedule E7 – Purchased Power

Schedule E8 – Energy Payments to Qualifying Facilities

Schedule E9 – Economy Energy Purchases

Schedule E10 – Residential Bill Comparison

Calculation of Inverted Residential Fuel Rate

Schedule H1 – Generating System Comparative Data

Capital Structure and Cost Rates Applied to Capital Projects

Duke Energy Florida, LLC
Fuel and Purchased Power Cost Recovery Clause
Estimated for the Period of : January 2021 through December 2021

				DOLLARS	mWh	CENTS/KWH
1.	Fuel Cost of System Net Generation (E3)			1,194,993,335	40,923,065	2.9201
2.	Coal Car Investment			0	0	0.0000
3.	Adjustment to Fuel Cost			13,261,552	0	0.0000
4.	TOTAL COST OF GENERATED POWER			1,208,254,887	40,923,065	2.9525
5.	Energy Cost of Purchased Power (Excl. Econ & Cogens) (E7)			9,333,612	199,674	4.6744
6.	Energy Cost of Economy Purchases (E9)			1,539,353	38,203	4.0294
7.	Payments to Qualifying Facilities (E8)			106,375,724	2,866,788	3.7106
8.	TOTAL COST OF PURCHASED POWER			117,248,689	3,104,665	3.7765
9.	TOTAL AVAILABLE mWh				44,027,729	
10.	Fuel Cost of Economy Sales	(E6)		(7,572,236)	(213,680)	3.5437
10a.	Gain on Economy Sales	(E6)		(1,920,095)	(213,680) *	0.8986
10b.	Gain on Total Power Sales - 20%	(E6)		47,511		
11.	Fuel Cost of Stratified Sales	(E6)		(36,852,618)	(1,735,681)	2.1232
12.	TOTAL FUEL COST AND GAINS ON POWER SALES			(46,297,438)	(1,949,360)	2.3750
13.	Net Inadvertent Interchange					
14.	TOTAL FUEL AND NET POWER TRANSACTIONS			1,279,206,138	42,078,369	3.0401
15.	Net Unbilled			(8,736,436) *	230,366	(0.0221)
16.	Company Use			5,522,249 *	(179,646)	0.0139
17.	T & D Losses			76,728,945 *	(2,523,902)	0.1937
18.	Adjusted System Sales			1,279,206,138	39,605,188	3.2257
19.	Wholesale Sales (Excluding Supplemental Sales)			(558,777)	(17,012)	3.2846
20.	Jurisdictional Sales			1,278,647,361	39,588,176	3.2299
21.	Jurisdictional Sales Adjusted for Line Losses x		1.00031	1,279,043,741	39,588,176	3.2309
22.	Prior Period True-Up (Sch E1-A)			(61,083,424)	39,588,176	(0.1543)
23.	Total Jurisdictional Fuel Cost			1,217,960,318	39,588,176	3.0766
24.	Revenue Tax Factor			876,931		1.0007
25.	Fuel Cost Adjusted for Taxes			1,218,837,249	39,588,176	3.0788
26.	GPIF **			4,407,712	39,588,176	0.0111
27.	Fuel Factor Adjusted for taxes including GPIF			1,223,244,961	39,588,176	3.0899
28.	Total Fuel Cost Factor (rounded to the nearest .001 cents/ KWH)					3.0900

* For Informational Purposes Only
** Based on Jurisdictional Sales

Duke Energy Florida, LLC
Calculation of Total True-Up
(Projected Period)
Estimated for the Period of : January 2021 through December 2021

1. Actual Over/(Under) Recovery January - December 2019 **(** Schedule E1-B, Page 2 of 2, Section C, Line 9 - Dec 19 **)**	$		(35,997,914)
2. Projected (Over)/Under Recovery January - December 2019 (Refunded)/Collected January - December 2020		14,462,684	
3. Midcourse Correction Amount approved in Order No. PSC-2020-0154-PCS-EI		(78,231,785)	
4. Adjusted (Over)/Under Recovery January - December 2019 (Lines 2 + 3) **(** Schedule E1-B, Page 2 of 2, Section C, Line 10 - Dec 19 **)**			(63,769,101)
5. Estimated Over/(Under) Recovery January - December 2020 **(** Schedule E1-B, Page 2 of 2, Section C, Line 8 - Dec 20 **)**			160,850,438
6. Total Over/(Under) Recovery (Lines 1 + 4 + 5)	$		61,083,423
7. Jurisdictional mWh Sales (Projected Period)	mWh		39,588,176
8. True-Up Factor (Line 6 / Line 7)	Cents/kWh		(0.154)

Duke Energy Florida, LLC
Calculation of Estimated True-Up
6 Months Actual and 6 Months Estimated
January 2020 - December 2020

			Jan Actual	Feb Actual	Mar Actual	Apr Actual	May Actual	Jun Actual	6 Month Sub-Total
A	1	Fuel Cost of System Generation	$ 74,992,301	$ 65,717,824	$ 73,293,028	$ 70,415,016	$ 87,128,507	$ 89,708,430	$ 461,255,106
	2	Fuel Cost of Power Sold	(1,105,818)	(1,159,871)	(1,312,152)	(2,612,318)	(5,495,100)	(6,606,107)	(18,291,367)
	3	Fuel Cost of Purchased Power	1,777,132	3,137,635	6,173,029	1,917,858	6,444,417	9,797,876	29,247,948
	3a	Demand and Non-Fuel Cost of Purchased Power							-
	3b	Energy Payments to Qualified Facilities	7,319,413	7,093,012	5,551,577	5,410,902	7,518,681	7,427,850	40,321,435
	4	Energy Cost of Economy Purchases	143,759	406,521	1,053,448	485,384	407,645	188,921	2,685,678
	5	Adjustments to Fuel Cost	(12,011,163)	1,119,402	1,152,738	1,147,328	1,142,435	1,139,918	(6,309,342)
	6	TOTAL FUEL & NET POWER TRANSACTIONS	71,115,625	76,314,523	85,911,668	76,764,171	97,146,585	101,656,887	508,909,459
		(Sum of Lines A1 Through A5)							
B	1	Jurisdictional mWh Sales	2,640,090	2,661,152	2,818,044	3,239,130	2,981,766	3,450,388	17,790,571
	2	Non-Jurisdictional mWh Sales	14,426	18,358	26,409	25,344	19,970	25,961	130,469
	3	TOTAL SALES (Lines B1 + B2)	2,654,517	2,679,511	2,844,453	3,264,474	3,001,736	3,476,349	17,921,039
	4	Jurisdictional % of Total Sales (Line B1/B3)	99.46%	99.31%	99.07%	99.22%	99.33%	99.25%	99.27%
C	1	Jurisdictional Fuel Recovery Revenue	85,968,564	86,669,575	91,874,742	103,746,698	25,329,422	115,589,082	509,178,083
		(Net of Revenue Taxes)							
	2	True-Up Provision	(1,205,224)	(1,205,224)	(1,205,224)	(1,205,224)	77,026,561	(1,205,224)	71,000,441
	2a	Incentive Provision	(215,975)	(215,975)	(215,975)	(215,975)	(215,975)	(215,975)	(1,295,850)
	3	FUEL REVENUE APPLICABLE TO PERIOD	84,547,365	85,248,376	90,453,543	102,325,499	102,140,008	114,167,883	578,882,674
		(Sum of Lines C1 Through C2a)							
	4	Fuel & Net Power Transactions (Line A6)	71,115,625	76,314,523	85,911,668	76,764,171	97,146,585	101,656,887	508,909,459
	5	Jurisdictional Total Fuel Costs & Net Power Transactions	70,755,650	75,811,447	85,139,074	76,189,021	96,525,617	100,925,738	505,346,546
		(Line A6 * Line B4 * Line Loss Multiplier)							
	6	Over/(Under) Recovery (Line C3 - Line C5)	13,791,715	9,436,929	5,314,469	26,136,477	5,614,392	13,242,145	73,536,127
	7	Interest Provision	(38,474)	(20,905)	(11,239)	9,273	(736)	(3,260)	(65,341)
	8	TOTAL ESTIMATED TRUE-UP FOR THE PERIOD	13,753,241	9,416,023	5,303,230	26,145,750	5,613,656	13,238,886	73,470,786
	9	Plus: Prior Period Balance	(35,997,914)	(35,997,914)	(35,997,914)	(35,997,914)	(35,997,914)	(35,997,914)	(35,997,914)
	10	Plus: Cumulative True-Up Provision	1,205,224	2,410,448	3,615,672	4,820,896	(72,205,665)	(71,000,441)	(71,000,441)
	11	Subtotal Prior Period True-up	(34,792,690)	(33,587,466)	(32,382,242)	(31,177,018)	(108,203,579)	(106,998,355)	(106,998,355)
	12	Regulatory Accounting Adjustment	-	-	-	-	-	-	-
	13	TOTAL TRUE-UP BALANCE	($21,039,449)	(10,418,201)	($3,909,747)	$23,441,228	($47,971,677)	($33,527,567)	(33,527,567)

Duke Energy Florida, LLC
Calculation of Estimated True-Up
6 Months Actual and 6 Months Estimated
January 2020 - December 2020

			Jul Estimated	Aug Estimated	Sep Estimated	Oct Estimated	Nov Estimated	Dec Estimated	12 Month Period
A	1	Fuel Cost of System Generation	$ 91,270,574	$ 102,001,873	$ 96,405,019	$ 90,833,949	$ 85,974,737	$ 97,148,448	$ 1,024,889,706
	2	Fuel Cost of Power Sold	(7,409,067)	(8,021,690)	(7,971,710)	(7,577,999)	(2,497,439)	(2,446,122)	(54,215,393)
	3	Fuel Cost of Purchased Power	8,533,384	4,575,768	3,696,906	4,358,593	1,085,538	174,484	51,672,621
	3a	Demand and Non-Fuel Cost of Purchased Power							0
	3b	Energy Payments to Qualified Facilities	8,407,595	8,411,122	7,949,571	7,091,011	8,225,712	9,032,312	89,438,758
	4	Energy Cost of Economy Purchases	177,886	113,649	178,038	128,590	91,292	125,383	3,500,516
	5	Adjustments to Fuel Cost	1,136,872	1,651,425	1,124,387	1,120,886	1,117,160	1,113,548	954,935
	6	TOTAL FUEL & NET POWER TRANSACTIONS (Sum of Lines A1 Through A5)	102,117,245	108,732,147	101,382,212	95,955,030	93,997,000	105,148,053	1,116,241,144
B	1	Jurisdictional mWh Sales	3,923,462	3,994,662	3,898,898	3,525,887	2,811,544	2,776,042	38,721,066
	2	Non-Jurisdictional mWh Sales	36,956	37,435	17,800	16,080	12,182	11,792	262,713
	3	TOTAL SALES (Lines B1 + B2)	3,960,418	4,032,097	3,916,698	3,541,967	2,823,725	2,787,834	38,983,778
	4	Jurisdictional % of Total Sales (Line B1/B3)	99.07%	99.07%	99.55%	99.55%	99.57%	99.58%	99.33%
C	1	Jurisdictional Fuel Recovery Revenue (Net of Revenue Taxes)	131,162,478	133,542,731	130,341,300	117,871,449	93,990,725	92,803,906	1,208,890,671
	2	True-Up Provision	(1,205,224)	(1,205,224)	(1,205,224)	(1,205,224)	(1,205,224)	(1,205,224)	63,769,102
	2a	Incentive Provision	(215,975)	(215,975)	(215,975)	(215,975)	(215,975)	(215,972)	(2,591,697)
	3	FUEL REVENUE APPLICABLE TO PERIOD (Sum of Lines C1 Through C2a)	129,741,279	132,121,532	128,920,101	116,450,250	92,569,526	91,382,710	1,270,068,076
	4	Fuel & Net Power Transactions (Line A6)	102,117,245	108,732,147	101,382,212	95,955,030	93,997,000	105,148,053	1,116,241,144
	5	Jurisdictional Total Fuel Costs & Net Power Transactions (Line A6 * Line B4 * Line Loss Multiplier)	101,198,916	107,754,331	100,957,279	95,552,845	93,621,826	104,738,890	1,109,170,633
	6	Over/(Under) Recovery (Line C3 - Line C5)	28,542,363	24,367,201	27,962,822	20,897,406	(1,052,301)	(13,356,180)	160,897,438
	7	Interest Provision	(1,489)	724	2,914	4,965	5,854	5,375	(46,998)
	8	TOTAL ESTIMATED TRUE-UP FOR THE PERIOD	28,540,875	24,367,925	27,965,736	20,902,370	(1,046,446)	(13,350,805)	160,850,440
	9	Plus: Prior Period Balance	(35,997,914)	(35,997,914)	(35,997,914)	(35,997,914)	(35,997,914)	(35,997,914)	(35,997,914)
	10	Plus: Cumulative True-Up Provision	(69,795,217)	(68,589,993)	(67,384,769)	(66,179,545)	(64,974,321)	(63,769,101)	(63,769,101)
	11	Subtotal Prior Period True-up	(105,793,131)	(104,587,907)	(103,382,683)	(102,177,459)	(100,972,235)	(99,767,015)	(99,767,015)
	12	Regulatory Accounting Adjustment	-	-	-	-	-	-	-
	13	TOTAL TRUE-UP BALANCE	($3,781,471)	$21,791,678	$50,962,638	$73,070,232	$73,229,010	$61,083,424	61,083,424

Duke Energy Florida, LLC
Calculation of Generating Performance Incentive
And True-Up Adjustment Factors
Estimated for the Period of : January 2021 through December 2021

1.	TOTAL AMOUNT OF ADJUSTMENTS:		
	A. Generating Performance Incentive Reward / (Penalty)	$	4,407,712
	B. True-Up (Over) / Under Recovery	$	(61,083,423)
2.	JURISDICTIONAL mWh SALES	mWh	39,588,176
3.	ADJUSTMENT FACTORS:		
	A. Generating Performance Incentive Factor	Cents/kWh	0.011
	B. True-Up Factor	Cents/kWh	(0.154)

Duke Energy Florida, LLC
Calculation of Levelized Fuel Adjustment Factors
Estimated for the Period of : January 2021 through December 2021

1.	Period Jurisdictional Fuel Cost (Schedule E-1, line 21)	$	1,279,043,741	
1a.	Prior Period True-up (E1, Line 22)	$	(61,083,423)	
2.	Regulatory Assessment Fee (E1, Line 24)	$	876,931	
3.	Generating Performance Incentive Factor (GPIF) (E1, Line 26)	$	4,407,712	
4.	Total Amount to be Recovered	$	1,223,244,961	
5.	Jurisdictional Sales (January - December 2018)		39,588,176	mWh
6.	Jurisdictional Cost per kWh Sold (Line 4 / Line 5 / 10)		3.090	Cents/kWh
7.	Effective Jurisdictional Sales (See Below)		39,537,944	mWh
	LEVELIZED FUEL FACTORS:			
8.	Fuel Factor at Secondary Metering (Line 4 / Line 7 / 10)		3.094	Cents/kWh
9.	Fuel Factor at Primary Metering		3.063	Cents/kWh
10.	Fuel Factor at Transmission Metering		3.032	Cents/kWh
	TIERED FUEL FACTORS:			
11	Fuel Factor - First Tier (0-1000 kWh)		2.811	Cents/kWh
12	Fuel Factor - Second Tier (Over 1000 kWh)		3.811	Cents/kWh

	JURISDICTIONAL SALES (mWh)	
METERING VOLTAGE:	METER	SECONDARY
Distr bution Secondary	35,139,125	35,139,125
Distr bution Primary	3,874,780	3,836,032
Transmission	574,272	562,787
Total	39,588,177	39,537,944

Duke Energy Florida, LLC
Calculation of Final Fuel Cost Factors
Estimated for the Period of : January 2021 through December 2021

Line:	Metering Voltage	First Tier Factor Cents/kWh	Second Tier Factor Cents/kWh	Levelized Factors Cents/kWh	Time of Use: On-Peak Multiplier 1.251	Time of Use: Off-Peak Multiplier 0.887
1.	Distribution Secondary	2.811	3.811	3.094	3.871	2.744
2.	Distribution Primary	--	--	3.063	3.832	2.717
3.	Transmission	--	--	3.032	3.793	2.689
4.	Lighting Service	--	--	2.955	--	--

Line 4 calculated at secondary rate of 3.094 * (18.7% * On-Peak Multiplier 1.251 + 81.3% * Off-Peak Multiplier 0.887).

DEVELOPMENT OF TIME OF USE MULTIPLIERS

	ON-PEAK PERIOD			OFF-PEAK PERIOD			TOTAL		
Mo/Yr	System mWh Requirements	Marginal Cost	Average Marginal Cost (¢/kWh)	System mWh Requirements	Marginal Cost	Average Marginal Cost (¢/kWh)	System mWh Requirements	Marginal Cost	Average Marginal Cost (¢/kWh)
Jan-21	756,754	21,617,479	2.857	2,222,863	47,575,762	2.140	2,979,617	69,193,241	2.322
Feb-21	729,170	20,321,485	2.787	1,915,928	40,149,923	2.096	2,645,099	60,471,408	2.286
Mar-21	795,546	22,006,559	2.766	2,081,214	45,237,332	2.174	2,876,760	67,243,892	2.337
Apr-21	1,028,363	29,443,537	2.863	1,962,489	39,465,471	2.011	2,990,853	68,909,008	2.304
May-21	1,154,698	36,694,869	3.178	2,583,131	53,277,643	2.063	3,737,829	89,972,512	2.407
Jun-21	1,418,773	46,433,212	3.273	2,647,610	56,630,579	2.139	4,066,384	103,063,791	2.535
Jul-21	1,455,958	47,007,583	3.229	2,867,913	62,701,301	2.186	4,323,870	109,708,883	2.537
Aug-21	1,427,810	45,291,532	3.172	2,842,612	61,501,115	2.164	4,270,421	106,792,648	2.501
Sep-21	1,322,741	39,995,530	3.024	2,713,883	58,126,063	2.142	4,036,624	98,121,593	2.431
Oct-21	1,133,866	33,172,131	2.926	2,364,207	50,544,214	2.138	3,498,073	83,716,344	2.393
Nov-21	712,194	18,225,379	2.559	2,086,588	45,426,830	2.177	2,798,782	63,652,210	2.274
Dec-21	813,045	22,166,467	2.726	2,085,386	42,839,181	2.054	2,898,430	65,005,648	2.243
TOTAL	12,748,916	382,375,763	2.999	28,373,826	603,475,414	2.127	41,122,742	985,851,178	2.397

	ON-PEAK	OFF-PEAK	AVERAGE
MARGINAL FUEL COST WEIGHTING MULTIPLIER	1.251	0.887	1.000

Duke Energy Florida, LLC
Development of Jurisdictional Delivery Loss Multipliers
Based on Actual Twelve Months Ending December 31, 2019
Estimated for the Period of : January 2021 through December 2021

		Energy Delivered @ Billing Level					Energy		
		Billed mWh	Unbilled mWh	Total mWh	% of Total	Delivery Efficiency	Required @ Source Level	% of Total	Jurisdictional Loss Multiplier
Retail									
Transmission		488,632	(1,049)	487,583		0.9836607	495,682		
Distribution Primary		3,630,168	(7,787)	3,622,381		0.9736607	3,720,373		
Distribution Secondary		35,068,543	(75,213)	34,993,330		0.9307248	37,597,934		
Total Retail		39,187,343	(84,049)	39,103,294	99.50%	0.9351725	41,813,989	99.53%	1.00031
						6.48%			
Wholesale									
Generation Level		169,009	-	169,009		1.0000000	169,009		
Transmission		-	-	-		0.9836607	-		
Distribution Primary		29,016	-	29,016		0.9736607	29,801		
Distribution Secondary		-	-	-			-		
Total Wholesale		198,025	-	198,025	0.50%	0.9960518	198,810	0.47%	0.93917
						0.39%			
Subtotal Class		39,385,368	(84,049)	39,301,319	100.00%	0.9354606	42,012,799	100.00%	1.00000
						6.45%			
Non-Class									
SEPA	Transmission	37,527	-	37,527		0.9836607	38,150		
Homestead Base & Int	Generation	38,551	-	38,551		1.0000000	38,551		
SECI - CC	Generation	1,018,150	-	1,018,150		1.0000000	1,018,150		
SECI - Base	Generation	-	-	-		1.0000000	-		
Reedy Creek Base & Int	Generation	451,217	-	451,217		1.0000000	451,217		
Reedy Creek Hines	Generation	229,861	-	229,861		1.0000000	229,861		
Reedy Creek Solar	Generation	2,448	-	2,448		1.0000000	2,448		
NSB - Peaking	Generation	-	-	-		1.0000000	-		
SECI - Intermediate	Generation	98,412	-	98,412		1.0000000	98,412		
SECI - Peaking	Generation	5,973	-	5,973		1.0000000	5,973		
TECO Base	Generation	838,669	-	838,669		1.0000000	838,669		
Interchange	Generation	59,125	-	59,125		1.0000000	59,125		
Company Use	Secondary	148,493	-	148,493		0.9307248	159,546		
Total Non-Class		2,928,426	-	2,928,426			2,940,102		
Total System		42,313,794	(84,049)	42,229,745		0.939422	44,952,901		

Duke Energy Florida, LLC
Fuel and Purchased Power Cost Recovery Clause
Estimated for the Period of : January 2021 through December 2021

			Estimated Jan-21	Estimated Feb-21	Estimated Mar-21	Estimated Apr-21	Estimated May-21	Estimated Jun-21	Estimated Jul-21	Estimated Aug-21	Estimated Sep-21	Estimated Oct-21	Estimated Nov-21	Estimated Dec-21	TOTAL
1	Fuel Cost of System Net Generation		$96,872,402	$85,036,001	$91,133,661	$84,783,693	$103,801,885	$111,433,201	$118,670,109	$117,845,407	$111,694,016	$99,760,893	$86,041,090	$87,920,977	$1,194,993,335
1a	Nuclear Fuel Disposal Cost		0	0	0	0	0	0	0	0	0	0	0	0	0
1b	Adjustments to Fuel Cost		1,124,711	1,121,218	1,117,500	1,114,006	1,110,845	1,107,127	1,103,410	1,099,803	1,096,197	1,092,700	1,088,657	1,085,378	13,261,552
2	Fuel Cost of Power Sold		(1,417,816)	(720,014)	(373,060)	(176,655)	(544,153)	(681,635)	(893,679)	(904,456)	(781,122)	(333,265)	(408,971)	(289,899)	(7,524,725)
2a	Gains on Power Sales		(359,516)	(182,574)	(94,597)	(44,794)	(137,981)	(172,842)	(226,611)	(229,344)	(198,069)	(84,507)	(103,703)	(85,557)	(1,920,095)
2b	Fuel Cost of Stratified Sales		(1,776,625)	(1,821,495)	(2,531,345)	(2,129,343)	(3,811,913)	(4,142,776)	(3,865,308)	(3,958,110)	(4,079,003)	(3,927,876)	(2,723,855)	(2,084,968)	(36,852,618)
3	Fuel Cost of Purchased Power (Excl Economy)		509,812	279,050	525,122	866,378	2,326,315	558,910	1,163,264	945,777	360,777	856,359	892,848	49,000	9,333,612
3a	Energy Payments to Qualifying Facilities		9,212,857	7,542,954	8,222,147	8,022,798	9,269,427	9,022,105	9,343,453	9,316,324	8,974,034	8,949,021	8,848,146	9,652,457	106,375,724
4	Energy Cost of Economy Purchases		79,297	95,430	155,108	149,250	194,346	205,130	111,190	98,450	68,453	90,445	145,770	146,484	1,539,353
5	Total System Fuel & Net Power Transactions		$104,245,122	$91,350,569	$98,154,536	$92,585,333	$112,208,771	$117,329,220	$125,405,828	$124,213,851	$117,135,284	$106,403,770	$93,779,982	$96,393,872	$1,279,206,138
6	Jurisdictional mWh Sold		3,019,064	2,828,366	2,610,944	2,660,944	2,992,525	3,618,140	3,984,399	4,016,879	4,115,362	3,815,333	3,167,483	2,758,734	39,588,176
7	Jurisdictional % of Total Sales		99.98%	99.97%	99.98%	99.97%	99.93%	99.94%	99.95%	99.95%	99.95%	99.94%	99.98%	99.95%	99.96%
8	Jurisdicitonal Fuel & Net Power Transactions		104,224,273	91,323,164	98,134,905	92,557,557	112,130,225	117,258,823	125,343,125	124,151,744	117,076,716	106,339,928	93,761,226	96,345,675	1,278,647,361
9	Jurisdictional Loss Multiplier		1.00031	1.00031	1.00031	1.00031	1.00031	1.00031	1.00031	1.00031	1.00031	1.00031	1.00031	1.00031	1.00031
10	Jurisdictional Fuel & Net Power Transactions		104,256,583	91,351,474	98,165,327	92,586,250	112,164,985	117,295,173	125,381,981	124,190,231	117,113,010	106,372,893	93,790,292	96,375,542	1,279,043,741
11	Adjusted System Sales	mWh	3,019,791	2,829,218	2,611,461	2,661,633	2,994,501	3,620,433	3,986,375	4,018,855	4,117,273	3,817,505	3,168,165	2,759,979	39,605,188
12	System Cost per kWh Sold	c/kWh	3.4520	3.2288	3.7586	3.4785	3.7471	3.2406	3.1459	3.0908	2.8450	2.7873	2.9601	3.4926	3.2299
13	Jurisdictional Loss Multiplier	x	1.00031	1.00031	1.00031	1.00031	1.00031	1.00031	1.00031	1.00031	1.00031	1.00031	1.00031	1.00031	1.00031
14	Jurisdictional Cost per kWh Sold	c/kWh	3.4533	3.2298	3.7598	3.4795	3.7482	3.2419	3.1468	3.0917	2.8458	2.7880	2.9610	3.4935	3.2309
15	Prior Period True-Up	+	-0.1686	-0.1800	-0.1950	-0.1913	-0.1701	-0.1407	-0.1278	-0.1267	-0.1237	-0.1334	-0.1607	-0.1845	-0.1543
16	Total Jurisdictional Fuel Expense	c/kWh	3.2847	3.0499	3.5648	3.2882	3.5781	3.1012	3.0191	2.9650	2.7221	2.6546	2.8003	3.3089	3.0766
17	Revenue Tax Multiplier	x	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072
18	Recovery Factor Adjusted for Taxes	c/kWh	3.2870	3.0521	3.5674	3.2905	3.5806	3.1034	3.0212	2.9671	2.7240	2.6565	2.8024	3.3113	3.0788
19	GPIF	+	0.0122	0.0130	0.0141	0.0138	0.0123	0.0102	0.0092	0.0091	0.0089	0.0096	0.0116	0.0133	0.0111
20	Total Recovery Factor (rounded .001)	c/kWh	3.299	3.065	3.581	3.304	3.593	3.114	3.030	2.976	2.733	2.666	2.814	3.325	3.090

Duke Energy Florida, LLC
Generating System Comparative Data by Fuel Type
Estimated for the Period of : January 2021 through December 2021

			Estimated Jan-21	Estimated Feb-21	Estimated Mar-21	Estimated Apr-21	Estimated May-21	Estimated Jun-21	Subtotal
	FUEL COST OF SYSTEM NET GENERATION ($)								
1	LIGHT OIL		1,014,622	963,575	762,635	574,512	934,006	975,912	5,225,262
2	COAL		19,463,507	15,630,604	18,634,230	8,986,470	16,121,450	17,457,382	96,293,643
3	GAS		76,394,273	68,441,822	71,736,796	75,222,711	86,746,429	92,999,907	471,541,938
4	OTHER		0	0	0	0	0	0	0
5	TOTAL	$	96,872,402	85,036,001	91,133,661	84,783,693	103,801,885	111,433,201	573,060,843
	SYSTEM NET GENERATION (MWH)								
6	LIGHT OIL		4,560	3,665	2,444	1,874	3,077	4,455	20,075
7	COAL		642,989	530,609	657,635	300,823	559,475	617,188	3,308,719
8	GAS		2,239,197	2,020,213	2,083,837	2,534,183	2,982,733	3,311,831	15,171,993
9	SOLAR		81,059	84,674	118,947	127,338	137,599	121,941	671,558
10	OTHER		0	0	0	0	0	0	0
11	TOTAL	MWH	2,967,805	2,639,161	2,862,863	2,964,218	3,682,884	4,055,415	19,172,346
	UNITS OF FUEL BURNED								
12	LIGHT OIL	BBL	9,131	8,349	6,337	4,526	8,256	9,065	45,664
13	COAL	TON	277,702	231,478	286,538	137,253	253,295	278,254	1,464,520
14	GAS	MCF	15,295,843	13,729,739	14,439,048	17,969,518	21,297,765	23,882,959	106,614,872
15	OTHER		0	0	0	0	0	0	0
	BTUS BURNED (MMBTU)								
16	LIGHT OIL		53,205	48,647	36,890	26,376	48,092	52,823	266,033
17	COAL		6,555,728	5,429,880	6,686,088	3,197,490	5,885,944	6,453,662	34,208,792
18	GAS		15,295,843	13,729,739	14,439,048	17,969,518	21,297,765	23,882,959	106,614,872
19	OTHER		0	0	0	0	0	0	0
20	TOTAL	MMBTU	21,904,776	19,208,266	21,162,026	21,193,384	27,231,801	30,389,444	141,089,697
	GENERATION MIX (% MWH)								
21	LIGHT OIL		0.15%	0.14%	0.09%	0.06%	0.08%	0.11%	0.11%
22	COAL		21.67%	20.11%	22.97%	10.15%	15.19%	15.22%	17.26%
23	GAS		75.45%	76.55%	72.79%	85.49%	80.99%	81.66%	79.14%
24	SOLAR		2.73%	3.21%	4.16%	4.30%	3.74%	3.01%	3.50%
25	OTHER		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
26	TOTAL	%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
	FUEL COST PER UNIT								
27	LIGHT OIL	$/BBL	111.12	115.41	120.35	126.94	113.13	107.66	114.43
28	COAL	$/TON	70.09	67.53	65.03	65.47	63.65	62.74	65.75
29	GAS	$/MCF	4.99	4.98	4.97	4.19	4.07	3.89	4.42
30	OTHER		0.00	0.00	0.00	0.00	0.00	0.00	0.00
	FUEL COST PER MMBTU ($/MMBTU)								
31	LIGHT OIL		19.07	19.81	20.67	21.78	19.42	18.48	19.64
32	COAL		2.97	2.88	2.79	2.81	2.74	2.71	2.82
33	GAS		4.99	4.99	4.97	4.19	4.07	3.89	4.42
34	OTHER		0.00	0.00	0.00	0.00	0.00	0.00	0.00
35	TOTAL	$/MMBTU	4.42	4.43	4.31	4.00	3.81	3.67	4.06
	BTU BURNED PER KWH (BTU/KWH)								
36	LIGHT OIL		11,668	13,273	15,093	14,077	15,628	11,856	13,252
37	COAL		10,196	10,233	10,167	10,629	10,520	10,457	10,339
38	GAS		6,831	6,796	6,929	7,091	7,140	7,211	7,027
39	OTHER		0	0	0	0	0	0	0
40	TOTAL	BTU/KWH	7,381	7,278	7,392	7,150	7,394	7,494	7,359
	GENERATED FUEL COST PER KWH (C/KWH)								
41	LIGHT OIL		22.25	26.29	31.20	30.66	30.35	21.90	26.03
42	COAL		3.03	2.95	2.83	2.99	2.88	2.83	2.91
43	GAS		3.41	3.39	3.44	2.97	2.91	2.81	3.11
44	OTHER		0.00	0.00	0.00	0.00	0.00	0.00	0.00
45	TOTAL	C/KWH	3.26	3.22	3.18	2.86	2.82	2.75	2.99

Duke Energy Florida, LLC
Generating System Comparative Data by Fuel Type
Estimated for the Period of : January 2021 through December 2021

			Estimated	Estimated	Estimated	Estimated	Estimated	Estimated	
			Jul-21	Aug-21	Sep-21	Oct-21	Nov-21	Dec-21	Total
	FUEL COST OF SYSTEM NET GENERATION ($)								
1	LIGHT OIL		973,781	945,198	985,311	895,692	820,384	1,046,309	10,891,937
2	COAL		18,015,119	17,754,298	15,831,804	16,049,666	15,920,152	9,770,815	189,635,497
3	GAS		99,681,209	99,145,911	94,876,901	82,815,535	69,300,554	77,103,853	994,465,901
4	OTHER		0	0	0	0	0	0	0
5	TOTAL	$	118,670,109	117,845,407	111,694,016	99,760,893	86,041,090	87,920,977	1,194,993,335
	SYSTEM NET GENERATION (MWH)								
6	LIGHT OIL		4,287	4,117	4,361	3,969	3,987	4,980	45,777
7	COAL		642,458	633,235	562,681	570,944	579,241	346,830	6,644,108
8	GAS		3,532,125	3,498,636	3,357,165	2,805,162	2,123,030	2,474,472	32,962,583
9	SOLAR		120,348	115,058	105,568	100,339	85,579	72,147	1,270,597
10	OTHER		0	0	0	0	0	0	0
11	TOTAL	MWH	4,299,218	4,251,045	4,029,775	3,480,414	2,791,837	2,898,430	40,923,065
	UNITS OF FUEL BURNED								
12	LIGHT OIL	BBL	9,067	8,892	9,301	8,586	7,561	9,760	98,831
13	COAL	TON	288,966	285,808	254,790	258,453	256,477	155,403	2,964,417
14	GAS	MCF	25,743,204	25,456,440	24,330,828	20,443,016	15,165,092	16,860,114	234,613,566
15	OTHER		0	0	0	0	0	0	0
	BTUS BURNED (MMBTU)								
16	LIGHT OIL		52,824	51,795	54,177	50,024	44,042	56,853	575,748
17	COAL		6,693,249	6,614,400	5,893,812	5,976,566	5,929,533	3,593,296	68,909,648
18	GAS		25,743,204	25,456,440	24,330,828	20,443,016	15,165,092	16,860,114	234,613,566
19	OTHER		0	0	0	0	0	0	0
20	TOTAL	MMBTU	32,489,277	32,122,635	30,278,817	26,469,606	21,138,667	20,510,263	304,098,962
	GENERATION MIX (% MWH)								
21	LIGHT OIL		0.10%	0.10%	0.11%	0.11%	0.14%	0.17%	0.11%
22	COAL		14.94%	14.90%	13.96%	16.40%	20.75%	11.97%	16.24%
23	GAS		82.16%	82.30%	83.31%	80.60%	76.04%	85.37%	80.55%
24	SOLAR		2.80%	2.71%	2.62%	2.88%	3.07%	2.49%	3.11%
25	OTHER		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
26	TOTAL	%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
	FUEL COST PER UNIT								
27	LIGHT OIL	$/BBL	107.40	106.30	105.94	104.32	108.50	107.20	110.21
28	COAL	$/TON	62.34	62.12	62.14	62.10	62.07	62.87	63.97
29	GAS	$/MCF	3.87	3.89	3.90	4.05	4.57	4.57	4.24
30	OTHER		0.00	0.00	0.00	0.00	0.00	0.00	0.00
	FUEL COST PER MMBTU ($/MMBTU)								
31	LIGHT OIL		18.43	18.25	18.19	17.91	18.63	18.40	18.92
32	COAL		2.69	2.68	2.69	2.69	2.69	2.72	2.75
33	GAS		3.87	3.90	3.90	4.05	4.57	4.57	4.24
34	OTHER		0.00	0.00	0.00	0.00	0.00	0.00	0.00
35	TOTAL	$/MMBTU	3.65	3.67	3.69	3.77	4.07	4.29	3.93
	BTU BURNED PER KWH (BTU/KWH)								
36	LIGHT OIL		12,323	12,582	12,423	12,602	11,045	11,415	12,577
37	COAL		10,418	10,445	10,475	10,468	10,237	10,360	10,372
38	GAS		7,288	7,276	7,247	7,288	7,143	6,814	7,118
39	OTHER		0	0	0	0	0	0	0
40	TOTAL	BTU/KWH	7,557	7,556	7,514	7,605	7,572	7,076	7,431
	GENERATED FUEL COST PER KWH (C/KWH)								
41	LIGHT OIL		22.72	22.96	22.59	22.56	20.57	21.01	23.79
42	COAL		2.80	2.80	2.81	2.81	2.75	2.82	2.85
43	GAS		2.82	2.83	2.83	2.95	3.26	3.12	3.02
44	OTHER		0.00	0.00	0.00	0.00	0.00	0.00	0.00
45	TOTAL	C/KWH	2.76	2.77	2.77	2.87	3.08	3.03	2.92

Duke Energy Florida, LLC
System Net Generation and Fuel Cost
Estimated for the Period of: Jan-21

	(A) PLANT/UNIT		(B) NET CAPACITY (MW)	(C) NET GENERATION (MWH)	(D) CAPACITY FACTOR (%)	(E) EQUIV AVA L FACTOR (%)	(F) OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE (BTU/KWH)	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)		(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MMBTU)	(L) AS BURNED FUEL COST ($)	(M) FUEL COST PER KWH (C/KWH)
1	CRYSTAL RIVER	4	732	348,547	64 0	96.13	68.0	10,221	COAL	150,904	TONS	23.61	3,562,398	10,566,781	3 03
2	CRYSTAL RIVER	5	712	294,442	55 6	94.52	60.7	10,166	COAL	126,798	TONS	23.61	2,993,330	8,896,726	3 02
3	ANCLOTE	1	517	17,897	4.7	98.06	15.0	12,595	GAS	225,409	MCF	1.00	225,409	912,510	5.10
4	ANCLOTE	2	521	1,063	0 3	98.39	15.7	13,755	GAS	14,615	MCF	1.00	14,615	285,818	26 90
5	AVON PARK	1-2	228	0	0 0	0.00	0.0	0	GAS	0	MCF	0.00	0	0	0 00
6	BARTOW	1-4	1,279	282	0.1	88.47	3.4	14,378	GAS	4,052	MCF	1.00	4,052	20,231	7.18
7	BARTOWCC	1	1279	585,300	61 5	90.65	67.8	6,929	GAS	4,055,769	MCF	1.00	4,055,769	20,248,573	3.46
8	CITRUS CC	1-2	1640	1,195,131	97 9	94.84	105.2	6,502	GAS	7,770,301	MCF	1.00	7,770,301	38,793,509	3 25
9	DEBARY	1-10	785	1,003	0 3	79.94	10.4	12,752	GAS	12,795	MCF	1.00	12,795	63,878	6 37
10	HINES	1-4	2,204	374,670	23 0	95.73	89.8	7,072	GAS	2,649,514	MCF	1.00	2,649,514	13,227,797	3 53
11	NT CITY	1-14	1,186	2,441	0.4	92.12	6.8	12,793	GAS	31,226	MCF	1.00	31,226	155,897	6 39
12	OSPREY	1	505	16,336	4 3	96.06	82.9	7,839	GAS	128,061	MCF	1.00	128,061	639,350	3 91
13	SUWANNEE CT	1-3	200	1,224	0 9	77.59	22.3	14,333	GAS	17,537	MCF	1.00	17,537	87,553	7.16
14	TIGER BAY	1	225	12,685	7 6	95.16	102.5	7,437	GAS	94,342	MCF	1.00	94,342	471,006	3.71
15	UNIV OF FLA.	1	47	31,166	89.1	97.42	91.5	9,376	GAS	292,222	MCF	1.00	292,222	1,488,151	4.77
16	AVON PARK	1-2	69	0	0 0	0.00	0.0	0	LIGHT OIL	0	BBLS		0	0	0 00
17	BARTOW	1-4	228	234	0 3	88.47	18.8	14,864	LIGHT OIL	597	BBLS	5.82	3,475	66,757	28 56
18	BARTOW CC	1	1,279	0	61 5	90.65	67.8	0	LIGHT OIL	0	BBLS	5.82	0	0	0 00
19	BAYBORO	1-4	231	220	0.1	92.34	23.9	13,258	LIGHT OIL	501	BBLS	5.82	2,922	74,051	33 60
20	DEBARY	1-10	785	958	0 3	79.94	10.4	12,721	LIGHT OIL	2,090	BBLS	5.82	12,182	256,854	26 82
21	HINESCC	1-4	2,204	1,664	23 0	95.73	89.8	7,306	LIGHT OIL	2,087	BBLS	5.82	12,160	180,197	10 83
22	OTHER		0	0	0 0	0.00	0.0	0	LIGHT OIL	0	BBLS	5.82	0	0	0 00
23	NT CITY	1-14	1,186	1,325	0.4	92.12	6.8	12,814	LIGHT OIL	2,914	BBLS	5.82	16,980	314,000	23.70
24	SUWANNEE CT	1-3	200	159	0 9	77.59	79.3	13,653	LIGHT OIL	372	BBLS	5.82	2,166	36,765	23.17
25	OTHER - START UP	0	-	0	-	0.00	0.0	0	LIGHT OIL	570	BBLS	5.82	3,320	85,998	0 00
26	SOLAR	1	513	81,059	21 2	0.00	46.7	0	SOLAR	0	N/A		0	0	0 00
27	TOTAL			2,967,805									21,904,776	96,872,402	3 26

Duke Energy Florida, LLC
System Net Generation and Fuel Cost
Estimated for the Period of: Feb-21

	(A) PLANT/UNIT		(B) NET CAPACITY (MW)	(C) NET GENERATION (MWH)	(D) CAPACITY FACTOR (%)	(E) EQUIV AVA L FACTOR (%)	(F) OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE (BTU/KWH)	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)		(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MMBTU)	(L) AS BURNED FUEL COST ($)	(M) FUEL COST PER KWH (C/KWH)
1	CRYSTAL RIVER	4	732	284,967	57 9	93.57	64.9	10,275	COAL	124,819	TONS	23.46	2,927,934	8,419,633	2.95
2	CRYSTAL RIVER	5	712	245,642	51 3	93.21	59.3	10,185	COAL	106,659	TONS	23.46	2,501,946	7,210,971	2.94
3	ANCLOTE	1	517	8,653	2 5	91.43	13.0	13,279	GAS	114,900	MCF	1 00	114,900	455,583	5.27
4	ANCLOTE	2	521	0	0 0	96.79	0.0	0	GAS	0	MCF	0 00	0	116,972	0.00
5	AVON PARK	1-2	228	0	0 0	0.00	0.0	0	GAS	0	MCF	0 00	0	0	0.00
6	BARTOW	1-4	1,279	156	0 0	86.16	2.9	14,905	GAS	2,320	MCF	1 00	2,320	11,564	7.43
7	BARTOWCC	1	1279	550,507	64.1	93.57	68.4	6,934	GAS	3,817,350	MCF	1 00	3,817,350	19,022,073	3.46
8	CITRUS CC	1-2	1640	1,115,680	101 2	97.14	104.7	6,485	GAS	7,235,591	MCF	1 00	7,235,591	36,055,365	3.23
9	DEBARY	1-10	785	1,287	0.4	79.61	9.2	13,351	GAS	17,188	MCF	1 00	17,188	85,647	6.65
10	H NES	1-4	2,204	297,580	20 2	82.41	90.1	7,075	GAS	2,105,275	MCF	1 00	2,105,275	10,490,700	3.53
11	INT CITY	1-14	1,186	3,495	0 6	92.83	6.1	13,340	GAS	46,626	MCF	1 00	46,626	232,337	6.65
12	OSPREY	1	505	11,519	3.4	95.72	84.5	8,185	GAS	94,284	MCF	1 00	94,284	469,821	4.08
13	SUWANNEE CT	1-3	200	1,377	1.1	83.22	21.7	14,432	GAS	19,869	MCF	1 00	19,869	99,004	7.19
14	TIGER BAY	1	225	2,507	1.7	93.57	101.3	7,480	GAS	18,755	MCF	1 00	18,755	93,457	3.73
15	UNIV OF FLA.	1	47	27,451	86 9	95.00	91.5	9,383	GAS	257,581	MCF	1 00	257,581	1,309,299	4.77
16	AVON PARK	1-2	69	0	0 0	0.00	0.0	0	LIGHT OIL	0	BBLS		0	0	0.00
17	BARTOW	1-4	228	211	0 2	86.16	16.1	15,219	LIGHT OIL	552	BBLS	5 83	3,218	62,151	29.39
18	BARTOW CC	1	1,279	0	64.1	93.57	68.4	0	LIGHT OIL	0	BBLS	5 83	0	0	0.00
19	BAYBORO	1-4	231	232	0.1	92.06	25.1	13,262	LIGHT OIL	528	BBLS	5 83	3,078	76,972	33.16
20	DEBARY	1-10	785	946	0.4	79.61	9.2	13,030	LIGHT OIL	2,116	BBLS	5 83	12,332	259,789	27.45
21	H NESCC	1-4	2,204	864	20 2	82.41	90.1	7,406	LIGHT OIL	1,099	BBLS	5 83	6,400	102,125	11.82
22	OTHER		0	0	0 0	0.00	0.0	0	LIGHT OIL	0	BBLS	5 83	0	0	0.00
23	INT CITY	1-14	1,186	1,309	0 6	92.83	6.1	12,842	LIGHT OIL	2,885	BBLS	5 83	16,812	311,147	23.77
24	SUWANNEE CT	1-3	200	102	1.1	83.22	50.9	13,869	LIGHT OIL	243	BBLS	5 83	1,412	24,847	24.41
25	OTHER - START UP	0	-	0	-	0.00	0.0	0	LIGHT OIL	926	BBLS	5 83	5,395	126,544	0.00
26	SOLAR	1	513	84,674	24 6	0.00	52.9	0	SOLAR	0	N/A		0	0	0.00
27	TOTAL			2,639,161									19,208,266	85,036,001	3.22

Duke Energy Florida, LLC
System Net Generation and Fuel Cost
Estimated for the Period of: Mar-21

	(A) PLANT/UNIT		(B) NET CAPACITY (MW)	(C) NET GENERATION (MWH)	(D) CAPACITY FACTOR (%)	(E) EQUIV AVA L FACTOR (%)	(F) OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE (BTU/KWH)	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)		(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MMBTU)	(L) AS BURNED FUEL COST ($)	(M) FUEL COST PER KWH (C/KWH)
1	CRYSTAL RIVER	4	732	367,030	67.4	96.45	70.7	10,184	COAL	160,190	TONS	23 33	3,737,874	10,403,845	2.83
2	CRYSTAL RIVER	5	712	290,605	54 9	91.29	62.3	10,145	COAL	126,348	TONS	23 33	2,948,214	8,230,385	2.83
3	ANCLOTE	1	517	23,331	6.1	91.29	16.7	12,432	GAS	290,061	MCF	1 00	290,061	1,230,867	5.28
4	ANCLOTE	2	521	7,179	1 9	98.06	17.9	13,082	GAS	93,908	MCF	1 00	93,908	676,147	9.42
5	AVON PARK	1-2	228	0	0 0	0.00	0.0	0	GAS	0	MCF	0 00	0	0	0.00
6	BARTOW	1-4	1,279	86	0 0	86.86	2.1	18,013	GAS	1,554	MCF	1 00	1,554	7,716	8.94
7	BARTOWCC	1	1279	645,097	67 8	90.81	70.3	6,946	GAS	4,481,004	MCF	1 00	4,481,004	22,255,263	3.45
8	CITRUS CC	1-2	1640	905,908	74 2	78.39	79.0	6,524	GAS	5,910,303	MCF	1 00	5,910,303	29,353,993	3.24
9	DEBARY	1-10	785	1,436	0.4	80.07	7.2	13,900	GAS	19,964	MCF	1 00	19,964	99,151	6.90
10	HINES	1-4	2,204	453,644	27.7	72.58	80.8	7,085	GAS	3,213,891	MCF	1 00	3,213,891	15,962,049	3.52
11	INT CITY	1-14	1,186	1,766	0 3	79.26	5.5	13,446	GAS	23,744	MCF	1 00	23,744	117,923	6.68
12	OSPREY	1	505	10,349	2 8	96.69	66.1	7,975	GAS	82,534	MCF	1 00	82,534	409,913	3.96
13	SUWANNEE CT	1-3	200	1,201	0 9	81.18	17.9	15,220	GAS	18,281	MCF	1 00	18,281	90,794	7.56
14	TIGER BAY	1	225	8,143	4 9	95.16	86.2	7,700	GAS	62,700	MCF	1 00	62,700	311,406	3.82
15	UNIV OF FLA.	1	47	25,697	73 5	95.77	91.4	9,383	GAS	241,104	MCF	1 00	241,104	1,221,574	4.75
16	AVON PARK	1-2	69	0	0 0	0.00	0.0	0	LIGHT OIL	0	BBLS		0	0	0.00
17	BARTOW	1-4	228	154	0.1	86.86	11.7	16,772	LIGHT OIL	442	BBLS	5 83	2,575	50,678	33.01
18	BARTOW CC	1	1,279	0	67 8	90.81	70.3	0	LIGHT OIL	0	BBLS	5 83	0	0	0.00
19	BAYBORO	1-4	231	167	0.1	94.20	18.0	14,853	LIGHT OIL	425	BBLS	5 83	2,476	62,169	37.29
20	DEBARY	1-10	785	725	0.4	80.07	7.2	13,479	LIGHT OIL	1,678	BBLS	5 83	9,768	209,540	28.91
21	HINESCC	1-4	2,204	0	27.7	72.58	80.8	0	LIGHT OIL	0	BBLS	5 83	0	15,378	0.00
22	OTHER		0	0	0 0	0.00	0.0	0	LIGHT OIL	0	BBLS	5 83	0	0	0.00
23	INT CITY	1-14	1,186	1,309	0 3	79.26	5.5	12,996	LIGHT OIL	2,923	BBLS	5 83	17,016	314,591	24.03
24	SUWANNEE CT	1-3	200	90	0 9	81.18	45.0	14,682	LIGHT OIL	228	BBLS	5 83	1,320	23,400	26.03
25	OTHER - START UP	0	-	0	-	0.00	0.0	0	LIGHT OIL	641	BBLS	5 83	3,735	86,879	0.00
26	SOLAR	1	513	118,947	31 2	0.00	61.2	0	SOLAR	0	N/A		0	0	0.00
27	TOTAL			2,862,863									21,162,026	91,133,661	3.18

Duke Energy Florida, LLC
System Net Generation and Fuel Cost
Estimated for the Period of: Apr-21

	(A) PLANT/UNIT		(B) NET CAPACITY (MW)	(C) NET GENERATION (MWH)	(D) CAPACITY FACTOR (%)	(E) EQUIV AVAIL FACTOR (%)	(F) OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE (BTU/KWH)	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)		(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MMBTU)	(L) AS BURNED FUEL COST ($)	(M) FUEL COST PER KWH (C/KWH)
1	CRYSTAL RIVER	4	732	296,302	56 2	97 67	60.1	10,631	COAL	135,215	TONS	23.30	3,150,002	8,740,723	2.95
2	CRYSTAL RIVER	5	712	4,521	0 9	6 67	57.7	10,504	COAL	2,038	TONS	23.30	47,488	245,747	5.44
3	ANCLOTE	1	517	65,939	17.7	91 00	23.4	11,539	GAS	760,903	MCF	1.00	760,903	2,609,094	3.96
4	ANCLOTE	2	521	6,117	1 6	96 00	34.5	12,063	GAS	73,786	MCF	1.00	73,786	884,432	14.46
5	AVON PARK	1-2	228	0	0 0	0 00	0.0	0	GAS	0	MCF	0.00	0	0	0.00
6	BARTOW	1-4	1,279	172	0 0	87.42	2.7	14,604	GAS	2,515	MCF	1.00	2,515	10,525	6.11
7	BARTOWCC	1	1279	631,021	68 5	95 33	71.8	7,117	GAS	4,490,795	MCF	1.00	4,490,795	18,795,865	2.98
8	CITRUS CC	1-2	1640	1,054,184	89 3	96 00	93.4	6,532	GAS	6,886,247	MCF	1.00	6,886,247	28,821,841	2.73
9	DEBARY	1-10	785	2,712	0 6	79 33	8.9	13,141	GAS	35,635	MCF	1.00	35,635	149,146	5.50
10	HINES	1-4	2,204	607,698	38 3	57 88	82.4	7,216	GAS	4,384,848	MCF	1.00	4,384,848	18,352,433	3.02
11	INT CITY	1-14	1,186	3,434	0 5	78 67	5.9	12,980	GAS	44,569	MCF	1.00	44,569	186,544	5.43
12	OSPREY	1	505	99,497	27.4	96 98	83.8	7,868	GAS	782,872	MCF	1.00	782,872	3,276,648	3.29
13	SUWANNEE CT	1-3	200	382	0 3	90.44	23.2	14,010	GAS	5,349	MCF	1.00	5,349	22,387	5.86
14	TIGER BAY	1	225	49,509	30 6	92 67	86.3	7,571	GAS	374,806	MCF	1.00	374,806	1,568,719	3.17
15	UNIV OF FLA.	1	47	13,519	40 0	93 57	91.6	9,408	GAS	127,193	MCF	1.00	127,193	545,077	4.03
16	AVON PARK	1-2	69	0	0 0	0 00	0.0	0	LIGHT OIL	0	BBLS		0	0	0.00
17	BARTOW	1-4	228	176	0 2	87.42	15.3	15,624	LIGHT OIL	471	BBLS	5.83	2,748	53,775	30.57
18	BARTOW CC	1	1,279	0	68 5	95 33	71.8	0	LIGHT OIL	0	BBLS	5.83	0	0	0.00
19	BAYBORO	1-4	231	164	0.1	93 25	17.8	13,926	LIGHT OIL	393	BBLS	5.83	2,288	57,341	34.90
20	DEBARY	1-10	785	799	0 6	79 33	8.9	13,313	LIGHT OIL	1,825	BBLS	5.83	10,634	226,482	28.35
21	HINESCC	1-4	2,204	0	38 3	57 88	82.4	0	LIGHT OIL	0	BBLS	5.83	0	15,378	0.00
22	OTHER		0	0	0 0	0 00	0.0	0	LIGHT OIL	0	BBLS	5.83	0	0	0.00
23	INT CITY	1-14	1,186	700	0 5	78 67	5.9	13,458	LIGHT OIL	1,616	BBLS	5.83	9,417	185,810	26.56
24	SUWANNEE CT	1-3	200	35	0 3	90.44	17.5	13,114	LIGHT OIL	79	BBLS	5.83	459	9,802	28.01
25	OTHER - START UP	0	-	0	-	0 00	0.0	0	LIGHT OIL	142	BBLS	5.83	830	25,924	0.00
26	SOLAR	1	513	127,338	34 5	0 00	63.6	0	SOLAR	0	N/A		0	0	0.00
27	TOTAL			2,964,218									21,193,384	84,783,693	2.86

Duke Energy Florida, LLC
System Net Generation and Fuel Cost
Estimated for the Period of: May-21

	(A) PLANT/UNIT		(B) NET CAPACITY (MW)	(C) NET GENERATION (MWH)	(D) CAPACITY FACTOR (%)	(E) EQUIV AVAIL FACTOR (%)	(F) OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE (BTU/KWH)	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)		(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MMBTU)	(L) AS BURNED FUEL COST ($)	(M) FUEL COST PER KWH (C/KWH)
1	CRYSTAL RIVER	4	732	286,088	52.5	83.23	63.1	10,569	COAL	130,116	TONS	23.24	3,023,568	8,278,305	2 89
2	CRYSTAL RIVER	5	712	273,387	51.6	95.16	58.7	10,470	COAL	123,179	TONS	23.24	2,862,376	7,843,145	2 87
3	ANCLOTE	1	517	28,969	7.5	23.26	25 0	11,587	GAS	335,662	MCF	1.00	335,662	1,463,903	5 05
4	ANCLOTE	2	521	37,034	9.6	96.77	26 0	12,355	GAS	457,566	MCF	1.00	457,566	1,765,861	4.77
5	AVON PARK	1-2	228	0	0.0	0.00	0 0	0	GAS	0	MCF	0.00	0	0	0 00
6	BARTOW	1-4	1,279	360	0.1	88.23	2 9	14,339	GAS	5,163	MCF	1.00	5,163	21,021	5 84
7	BARTOWCC	1	1279	695,039	73.0	98.06	74.4	7,137	GAS	4,960,212	MCF	1.00	4,960,212	20,196,349	2 91
8	CITRUS CC	1-2	1640	1,091,918	89.5	95.48	94 2	6,527	GAS	7,127,480	MCF	1.00	7,127,480	29,020,749	2 66
9	DEBARY	1-10	785	6,157	1.2	79.81	9.4	12,945	GAS	79,705	MCF	1.00	79,705	324,532	5 27
10	HINES	1-4	2,204	847,414	51.7	63.73	81.4	7,209	GAS	6,109,011	MCF	1.00	6,109,011	24,873,882	2 94
11	NT CITY	1-14	1,186	8,452	1.1	82.66	6 3	12,842	GAS	108,539	MCF	1.00	108,539	441,934	5 23
12	OSPREY	1	505	147,423	39.2	96.50	80 9	7,795	GAS	1,149,219	MCF	1.00	1,149,219	4,679,242	3.17
13	SUWANNEE CT	1-3	200	1,001	0.7	80.00	24 2	13,681	GAS	13,690	MCF	1.00	13,690	55,742	5 57
14	TIGER BAY	1	225	88,110	52.6	94.84	87 0	7,514	GAS	662,045	MCF	1.00	662,045	2,695,629	3 06
15	UNIV OF FLA.	1	47	30,857	88.2	96.45	91.4	9,381	GAS	289,473	MCF	1.00	289,473	1,207,585	3 91
16	AVON PARK	1-2	69	0	0.0	0.00	0 0	0	LIGHT O L	0	BBLS		0	0	0 00
17	BARTOW	1-4	228	191	0.3	88.23	16.1	15,276	LIGHT O L	501	BBLS	5.83	2,920	56,856	29.74
18	BARTOW CC	1	1,279	0	73.0	98.06	74.4	0	LIGHT O L	0	BBLS	5.83	0	0	0 00
19	BAYBORO	1-4	231	163	0.1	94.20	17 6	13,838	LIGHT O L	387	BBLS	5.83	2,250	56,063	34.48
20	DEBARY	1-10	785	791	1.2	79.81	9.4	13,221	LIGHT O L	1,796	BBLS	5.83	10,459	223,057	28 20
21	HINESCC	1-4	2,204	866	51.7	63.73	81.4	7,202	LIGHT O L	1,070	BBLS	5.83	6,235	99,890	11 54
22	OTHER		0	0	0.0	0.00	0 0	0	LIGHT O L	0	BBLS	5.83	0	0	0 00
23	NT CITY	1-14	1,186	955	1.1	82.66	6 3	12,855	LIGHT O L	2,107	BBLS	5.83	12,277	234,281	24 53
24	SUWANNEE CT	1-3	200	112	0.7	80.00	55 8	13,446	LIGHT O L	258	BBLS	5.83	1,501	26,260	23 52
25	OTHER - START UP	0	-	0	-	0.00	0 0	0	LIGHT O L	2,137	BBLS	5.83	12,450	237,599	0 00
26	SOLAR	1	513	137,599	36.1	0.00	66 6	0	SOLAR	0	N/A		0	0	0 00
27	TOTAL			3,682,884									27,231,801	103,801,885	2 82

Duke Energy Florida, LLC
System Net Generation and Fuel Cost
Estimated for the Period of: Jun-21

(A)		(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)		(J)	(K)	(L)	(M)
PLANT/UNIT		NET CAPACITY (MW)	NET GENERATION (MWH)	CAPACITY FACTOR (%)	EQUIV AVA L FACTOR (%)	OUTPUT FACTOR (%)	AVG. NET HEAT RATE (BTU/KWH)	FUEL TYPE	FUEL BURNED (UNITS)		FUEL HEAT VALUE (BTU/UNIT)	FUEL BURNED (MMBTU)	AS BURNED FUEL COST ($)	FUEL COST PER KWH (C/KWH)
1 CRYSTAL RIVER	4	732	326,247	61 9	91.33	67.7	10,488	COAL	147,531	TONS	23.19	3,421,743	9,248,945	2 83
2 CRYSTAL RIVER	5	712	290,941	56 8	94.33	62.8	10,421	COAL	130,723	TONS	23.19	3,031,919	8,208,437	2 82
3 ANCLOTE	1	517	99,464	26.7	92.67	28.6	11,223	GAS	1,116,292	MCF	1.00	1,116,292	3,800,244	3 82
4 ANCLOTE	2	521	27,076	7 2	97.33	31.7	11,974	GAS	324,221	MCF	1.00	324,221	1,807,394	6 68
5 AVON PARK	1-2	228	0	0 0	0.00	0.0	0	GAS	0	MCF	0.00	0	0	0 00
6 BARTOW	1-4	1,279	251	0 0	86.92	2.7	14,369	GAS	3,610	MCF	1.00	3,610	14,053	5 59
7 BARTOWCC	1	1279	666,327	72.4	96.00	75.4	7,143	GAS	4,759,295	MCF	1.00	4,759,295	18,527,014	2.78
8 CITRUS CC	1-2	1640	1,081,637	91 6	95.67	96.4	6,517	GAS	7,049,116	MCF	1.00	7,049,116	27,440,847	2 54
9 DEBARY	1-10	785	7,190	1.4	80.13	9.9	12,835	GAS	92,285	MCF	1.00	92,285	359,246	5 00
10 HINES	1-4	2,204	1,186,013	74 8	97.09	81.6	7,201	GAS	8,540,499	MCF	1.00	8,540,499	33,246,512	2 80
11 NT CITY	1-14	1,186	11,869	1 6	93.10	6.3	12,811	GAS	152,055	MCF	1.00	152,055	591,924	4 99
12 OSPREY	1	505	135,015	37.1	96.54	88.5	7,786	GAS	1,051,217	MCF	1.00	1,051,217	4,092,186	3 03
13 SUWANNEE CT	1-3	200	1,610	1 2	84.17	24.8	13,534	GAS	21,788	MCF	1.00	21,788	84,815	5 27
14 TIGER BAY	1	225	65,346	40 3	95.67	88.5	7,513	GAS	490,972	MCF	1.00	490,972	1,911,261	2 92
15 UNIV OF FLA.	1	47	30,031	88.7	97.00	91.5	9,377	GAS	281,609	MCF	1.00	281,609	1,124,411	3.74
16 AVON PARK	1-2	69	0	0 0	0.00	0.0	0	LIGHT OIL	0	BBLS		0	0	0 00
17 BARTOW	1-4	228	165	0 3	86.92	15.2	15,602	LIGHT OIL	442	BBLS	5.84	2,580	50,749	30 69
18 BARTOW CC	1	1,279	0	72.4	96.00	75.4	0	LIGHT OIL	0	BBLS	5.84	0	0	0 00
19 BAYBORO	1-4	231	150	0.1	92.17	16.2	13,850	LIGHT OIL	356	BBLS	5.84	2,072	51,574	34.47
20 DEBARY	1-10	785	789	1.4	80.13	9.9	13,175	LIGHT OIL	1,784	BBLS	5.84	10,394	221,776	28.11
21 HINESCC	1-4	2,204	1,745	74 8	97.09	81.6	7,147	LIGHT OIL	2,141	BBLS	5.84	12,470	184,402	10 57
22 OTHER		0	0	0 0	0.00	0.0	0	LIGHT OIL	0	BBLS	5.84	0	0	0 00
23 NT CITY	1-14	1,186	1,480	1 6	93.10	6.3	12,870	LIGHT OIL	3,267	BBLS	5.84	19,045	348,958	23 58
24 SUWANNEE CT	1-3	200	127	1 2	84.17	63.4	13,385	LIGHT OIL	291	BBLS	5.84	1,697	29,352	23.15
25 OTHER - START UP	0	-	0	-	0.00	0.0	0	LIGHT OIL	784	BBLS	5.84	4,565	89,101	0 00
26 SOLAR	1	513	121,941	33 0	0.00	59.4	0	SOLAR	0	N/A		0	0	0 00
27 TOTAL			4,055,415									30,389,444	111,433,201	2.75

Duke Energy Florida, LLC
System Net Generation and Fuel Cost
Estimated for the Period of: Jul-21

	(A) PLANT/UNIT		(B) NET CAPACITY (MW)	(C) NET GENERATION (MWH)	(D) CAPACITY FACTOR (%)	(E) EQUIV AVAIL FACTOR (%)	(F) OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE (BTU/KWH)	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)		(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MMBTU)	(L) AS BURNED FUEL COST ($)	(M) FUEL COST PER KWH (C/KWH)
1	CRYSTAL RIVER	4	732	364,955	67.0	94 84	70.6	10,446	COAL	164,585	TONS	23.16	3,812,242	10,244,685	2 81
2	CRYSTAL RIVER	5	712	277,503	52.4	88.71	66.5	10,382	COAL	124,381	TONS	23.16	2,881,007	7,770,434	2 80
3	ANCLOTE	1	517	75,843	19.7	87.74	29.0	11,212	GAS	850,337	MCF	1 00	850,337	3,562,018	4.70
4	ANCLOTE	2	521	103,982	26.8	98 06	27.5	12,138	GAS	1,262,099	MCF	1 00	1,262,099	4,615,305	4.44
5	AVON PARK	1-2	228	0	0.0	0 00	0.0	0	GAS	0	MCF	0 00	0	0	0 00
6	BARTOW	1-4	1,279	248	0.0	87.18	2.8	14,208	GAS	3,526	MCF	1 00	3,526	13,649	5 50
7	BARTOWCC	1	1279	675,907	71.0	93 55	75.9	7,146	GAS	4,830,221	MCF	1 00	4,830,221	18,697,969	2.77
8	CITRUS CC	1-2	1640	1,138,765	93.3	96.45	97.1	6,510	GAS	7,413,922	MCF	1 00	7,413,922	28,699,574	2 52
9	DEBARY	1-10	785	9,015	1.7	80.45	9.9	12,809	GAS	115,481	MCF	1 00	115,481	447,032	4 96
10	HINES	1-4	2,204	1,232,815	75.3	92 82	83.0	7,202	GAS	8,878,192	MCF	1 00	8,878,192	34,367,819	2.79
11	NT CITY	1-14	1,186	12,774	1.6	92 54	6.5	12,794	GAS	163,438	MCF	1 00	163,438	632,677	4 95
12	OSPREY	1	505	167,170	44.5	94 58	85.8	7,720	GAS	1,290,516	MCF	1 00	1,290,516	4,995,637	2 99
13	SUWANNEE CT	1-3	200	2,034	1.5	82.42	24.7	13,479	GAS	27,417	MCF	1 00	27,417	106,130	5 22
14	TIGER BAY	1	225	83,438	49.8	95 81	88.9	7,494	GAS	625,252	MCF	1 00	625,252	2,420,376	2 90
15	UNIV OF FLA.	1	47	30,134	86.2	94.19	91.5	9,385	GAS	282,803	MCF	1 00	282,803	1,123,023	3.73
16	AVON PARK	1-2	69	0	0.0	0 00	0.0	0	LIGHT O L	0	BBLS		0	0	0 00
17	BARTOW	1-4	228	175	0.2	87.18	15.5	15,524	LIGHT O L	467	BBLS	5 83	2,722	53,308	30.40
18	BARTOW CC	1	1,279	0	71.0	93 55	75.9	0	LIGHT O L	0	BBLS	5 83	0	0	0 00
19	BAYBORO	1-4	231	146	0.1	94.19	15.7	13,849	LIGHT O L	346	BBLS	5 83	2,015	49,941	34 32
20	DEBARY	1-10	785	884	1.7	80.45	9.9	13,302	LIGHT O L	2,018	BBLS	5 83	11,753	248,448	28.12
21	HINESCC	1-4	2,204	1,747	75.3	92 82	83.0	7,139	LIGHT O L	2,141	BBLS	5 83	12,470	184,402	10 56
22	OTHER		0	0	0.0	0 00	0.0	0	LIGHT O L	0	BBLS	5 83	0	0	0 00
23	NT CITY	1-14	1,186	1,198	1.6	92 54	6.5	12,863	LIGHT O L	2,644	BBLS	5 83	15,408	287,312	23 98
24	SUWANNEE CT	1-3	200	138	1.5	82.42	68.8	13,205	LIGHT O L	312	BBLS	5 83	1,816	31,234	22.71
25	OTHER - START UP	0	-	0	-	0 00	0.0	0	LIGHT O L	1,139	BBLS	5 83	6,640	119,136	0 00
26	SOLAR	1	513	120,348	31.5	0 00	56.9	0	SOLAR	0	N/A		0	0	0 00
27	TOTAL			4,299,218									32,489,277	118,670,109	2.76

Duke Energy Florida, LLC
System Net Generation and Fuel Cost
Estimated for the Period of: Aug-21

	(A) PLANT/UNIT		(B) NET CAPACITY (MW)	(C) NET GENERATION (MWH)	(D) CAPACITY FACTOR (%)	(E) EQUIV AVAIL FACTOR (%)	(F) OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE (BTU/KWH)	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)		(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MMBTU)	(L) AS BURNED FUEL COST ($)	(M) FUEL COST PER KWH (C/KWH)
1	CRYSTAL RIVER	4	732	344,426	63 2	95.81	68 9	10,472	COAL	155,856	TONS	23.14	3,606,938	9,671,214	2.81
2	CRYSTAL RIVER	5	712	288,809	54 5	85.81	63 6	10,413	COAL	129,952	TONS	23.14	3,007,462	8,083,084	2.80
3	ANCLOTE	1	517	75,179	19 5	90.32	29 5	11,203	GAS	842,199	MCF	1.00	842,199	3,532,301	4.70
4	ANCLOTE	2	521	99,977	25 8	98.06	26 3	12,229	GAS	1,222,658	MCF	1.00	1,222,658	4,507,417	4.51
5	AVON PARK	1-2	228	0	0 0	0.00	0 0	0	GAS	0	MCF	0.00	0	0	0.00
6	BARTOW	1-4	1,279	287	0 0	87.66	3 3	14,247	GAS	4,083	MCF	1.00	4,083	15,899	5.55
7	BARTOWCC	1	1279	667,958	70 2	93.55	75.1	7,139	GAS	4,768,327	MCF	1.00	4,768,327	18,565,931	2.78
8	CITRUS CC	1-2	1640	1,133,605	92 9	96.45	96.7	6,512	GAS	7,382,386	MCF	1.00	7,382,386	28,744,018	2.54
9	DEBARY	1-10	785	6,399	1 2	79.87	9 9	12,818	GAS	82,024	MCF	1.00	82,024	319,367	4.99
10	HINES	1-4	2,204	1,243,355	75 9	95.16	81.4	7,204	GAS	8,957,475	MCF	1.00	8,957,475	34,876,779	2.81
11	INT CITY	1-14	1,186	9,059	1 2	91.89	6 5	12,799	GAS	115,944	MCF	1.00	115,944	451,440	4.98
12	OSPREY	1	505	151,140	40 2	97.33	88 8	7,776	GAS	1,175,206	MCF	1.00	1,175,206	4,575,775	3.03
13	SUWANNEE CT	1-3	200	1,803	1 3	83.39	24 8	13,512	GAS	24,362	MCF	1.00	24,362	94,854	5.26
14	TIGER BAY	1	225	79,122	47 3	92.58	88 8	7,498	GAS	593,237	MCF	1.00	593,237	2,309,824	2.92
15	UNIV OF FLA.	1	47	30,754	87 9	96.13	91 5	9,382	GAS	288,539	MCF	1.00	288,539	1,152,306	3.75
16	AVON PARK	1-2	69	0	0 0	0.00	0 0	0	LIGHT OIL	0	BBLS		0	0	0.00
17	BARTOW	1-4	228	176	0 3	87.66	18.4	14,965	LIGHT OIL	452	BBLS	5.81	2,628	51,620	29.39
18	BARTOW CC	1	1,279	0	70 2	93.55	75.1	0	LIGHT OIL	0	BBLS	5.81	0	0	0.00
19	BAYBORO	1-4	231	146	0.1	92.02	15 8	13,841	LIGHT OIL	347	BBLS	5.81	2,018	49,703	34.09
20	DEBARY	1-10	785	807	1 2	79.87	9 9	13,196	LIGHT OIL	1,828	BBLS	5.81	10,648	226,735	28.10
21	HINESCC	1-4	2,204	1,732	75 9	95.16	81.4	7,148	LIGHT OIL	2,125	BBLS	5.81	12,378	183,155	10.58
22	OTHER		0	0	0 0	0.00	0 0	0	LIGHT OIL	0	BBLS	5.81	0	0	0.00
23	INT CITY	1-14	1,186	1,125	1 2	91.89	6 5	12,876	LIGHT OIL	2,485	BBLS	5.81	14,483	271,644	24.15
24	SUWANNEE CT	1-3	200	132	1 3	83.39	65 9	13,316	LIGHT OIL	301	BBLS	5.81	1,755	30,265	22.96
25	OTHER - START UP	0	-	0	-	0.00	0 0	0	LIGHT OIL	1,354	BBLS	5.81	7,885	132,076	0.00
26	SOLAR	1	513	115,058	30.1	0.00	55.7	0	SOLAR	0	N/A		0	0	0.00
27	TOTAL			4,251,045									32,122,635	117,845,407	2.77

Duke Energy Florida, LLC
System Net Generation and Fuel Cost
Estimated for the Period of: Sep-21

	(A) PLANT/UNIT		(B) NET CAPACITY (MW)	(C) NET GENERATION (MWH)	(D) CAPACITY FACTOR (%)	(E) EQUIV AVAIL FACTOR (%)	(F) OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE (BTU/KWH)	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)		(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MMBTU)	(L) AS BURNED FUEL COST ($)	(M) FUEL COST PER KWH (C/KWH)
1	CRYSTAL RIVER	4	732	279,095	53 0	90.67	66.5	10,511	COAL	126,814	TONS	23.13	2,933,461	7,880,315	2.82
2	CRYSTAL RIVER	5	712	283,586	55 3	90.00	61.5	10,439	COAL	127,976	TONS	23.13	2,960,351	7,951,489	2.80
3	ANCLOTE	1	517	61,799	16 6	94.00	29.2	11,213	GAS	692,956	MCF	1.00	692,956	2,970,159	4.81
4	ANCLOTE	2	521	88,067	23 5	94.00	25.0	12,376	GAS	1,089,929	MCF	1.00	1,089,929	3,980,060	4.52
5	AVON PARK	1-2	228	0	0 0	0.00	0.0	0	GAS	0	MCF	0.00	0	0	0.00
6	BARTOW	1-4	1,279	250	0 0	86.50	2.9	14,316	GAS	3,582	MCF	1.00	3,582	13,963	5.58
7	BARTOWCC	1	1279	651,309	70.7	94.67	74.7	7,137	GAS	4,648,417	MCF	1.00	4,648,417	18,120,920	2.78
8	CITRUS CC	1-2	1640	1,095,419	92 8	96.67	96.4	6,513	GAS	7,134,532	MCF	1.00	7,134,532	27,812,540	2.54
9	DEBARY	1-10	785	4,688	1 0	79.50	9.7	12,834	GAS	60,160	MCF	1.00	60,160	234,521	5.00
10	H NES	1-4	2,204	1,219,002	76 9	96.50	80.8	7,206	GAS	8,784,361	MCF	1.00	8,784,361	34,244,065	2.81
11	INT CITY	1-14	1,186	8,027	1.1	92.00	6.4	12,819	GAS	102,899	MCF	1.00	102,899	401,126	5.00
12	OSPREY	1	505	128,923	35 5	93.57	89.0	7,787	GAS	1,003,900	MCF	1.00	1,003,900	3,913,501	3.04
13	SUWANNEE CT	1-3	200	1,263	1 0	83.50	24.5	13,560	GAS	17,132	MCF	1.00	17,132	66,785	5.29
14	TIGER BAY	1	225	68,490	42 3	93.33	88.7	7,480	GAS	512,318	MCF	1.00	512,318	1,997,169	2.92
15	UNIV OF FLA.	1	47	29,928	88.4	96.67	91.5	9,377	GAS	280,642	MCF	1.00	280,642	1,122,092	3.75
16	AVON PARK	1-2	69	0	0 0	0.00	0.0	0	LIGHT OIL	0	BBLS		0	0	0.00
17	BARTOW	1-4	228	152	0 2	86.50	16.0	15,608	LIGHT OIL	407	BBLS	5.82	2,369	46,990	30.96
18	BARTOW CC	1	1,279	0	70.7	94.67	74.7	0	LIGHT OIL	0	BBLS	5.82	0	0	0.00
19	BAYBORO	1-4	231	158	0.1	92.92	17.1	13,841	LIGHT OIL	377	BBLS	5.82	2,191	53,293	33.67
20	DEBARY	1-10	785	814	1 0	79.50	9.7	13,180	LIGHT OIL	1,841	BBLS	5.82	10,727	228,313	28.05
21	H NESCC	1-4	2,204	1,658	76 9	96.50	80.8	7,143	LIGHT OIL	2,034	BBLS	5.82	11,846	175,950	10.61
22	OTHER		0	0	0 0	0.00	0.0	0	LIGHT OIL	0	BBLS	5.82	0	0	0.00
23	INT CITY	1-14	1,186	1,472	1.1	92.00	6.4	12,887	LIGHT OIL	3,255	BBLS	5.82	18,970	347,708	23.62
24	SUWANNEE CT	1-3	200	107	1 0	83.50	53.4	13,435	LIGHT OIL	247	BBLS	5.82	1,434	25,212	23.62
25	OTHER - START UP	0	-	0	-	0.00	0.0	0	LIGHT OIL	1,140	BBLS	5.82	6,640	107,845	0.00
26	SOLAR	1	513	105,568	28 6	0.00	54.4	0	SOLAR	0	N/A		0	0	0.00
27	TOTAL			4,029,775									30,278,817	111,694,016	2.77

Duke Energy Florida, LLC
System Net Generation and Fuel Cost
Estimated for the Period of: Oct-21

	(A) PLANT/UNIT		(B) NET CAPACITY (MW)	(C) NET GENERATION (MWH)	(D) CAPACITY FACTOR (%)	(E) EQUIV AVAIL FACTOR (%)	(F) OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE (BTU/KWH)	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)		(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MMBTU)	(L) AS BURNED FUEL COST ($)	(M) FUEL COST PER KWH (C/KWH)
1	CRYSTAL RIVER	4	732	288,742	53.0	91.29	66.9	10,496	COAL	131,056	TONS	23.12	3,030,588	8,136,853	2.82
2	CRYSTAL RIVER	5	712	282,202	53.3	90.00	61.0	10,439	COAL	127,397	TONS	23.12	2,945,978	7,912,813	2.80
3	ANCLOTE	1	517	47,468	12.3	95.16	28.7	11,265	GAS	534,730	MCF	1.00	534,730	2,380,937	5.02
4	ANCLOTE	2	521	65,961	17.0	95.16	24.3	12,438	GAS	820,451	MCF	1.00	820,451	3,108,097	4.71
5	AVON PARK	1-2	228	0	0.0	0.00	0.0	0	GAS	0	MCF	0.00	0	0	0.00
6	BARTOW	1-4	1,279	149	0.0	89.20	3.1	14,320	GAS	2,140	MCF	1.00	2,140	8,668	5.80
7	BARTOWCC	1	1279	577,938	60.7	79.05	64.9	7,215	GAS	4,169,671	MCF	1.00	4,169,671	16,888,862	2.92
8	CITRUS CC	1-2	1640	705,121	57.8	58.18	96.6	6,528	GAS	4,602,904	MCF	1.00	4,602,904	18,643,634	2.64
9	DEBARY	1-10	785	3,034	0.6	65.94	9.4	12,881	GAS	39,082	MCF	1.00	39,082	158,295	5.22
10	H NES	1-4	2,204	1,207,799	73.8	88.92	82.9	7,196	GAS	8,691,203	MCF	1.00	8,691,203	35,202,907	2.91
11	INT CITY	1-14	1,186	6,221	0.8	91.89	6.3	12,800	GAS	79,630	MCF	1.00	79,630	322,539	5.18
12	OSPREY	1	505	155,200	41.3	97.67	78.2	7,710	GAS	1,196,624	MCF	1.00	1,196,624	4,846,813	3.12
13	SUWANNEE CT	1-3	200	1,235	0.9	83.87	24.1	13,586	GAS	16,782	MCF	1.00	16,782	67,975	5.50
14	TIGER BAY	1	225	21,207	12.7	93.33	88.1	7,532	GAS	159,738	MCF	1.00	159,738	647,002	3.05
15	UNIV OF FLA.	1	47	13,829	39.5	95.71	91.4	9,405	GAS	130,061	MCF	1.00	130,061	539,806	3.90
16	AVON PARK	1-2	69	0	0.0	0.00	0.0	0	LIGHT OIL	0	BBLS		0	0	0.00
17	BARTOW	1-4	228	170	0.2	89.20	17.5	15,540	LIGHT OIL	452	BBLS	5.83	2,635	51,749	30.52
18	BARTOW CC	1	1,279	0	60.7	79.05	64.9	0	LIGHT OIL	0	BBLS	5.83	0	0	0.00
19	BAYBORO	1-4	231	150	0.1	93.47	16.2	13,836	LIGHT OIL	356	BBLS	5.83	2,074	50,347	33.59
20	DEBARY	1-10	785	665	0.6	65.94	9.4	13,275	LIGHT OIL	1,515	BBLS	5.83	8,823	191,002	28.74
21	H NESCC	1-4	2,204	1,812	73.8	88.92	82.9	7,125	LIGHT OIL	2,216	BBLS	5.83	12,909	190,359	10.51
22	OTHER		0	0	0.0	0.00	0.0	0	LIGHT OIL	0	BBLS	5.83	0	0	0.00
23	INT CITY	1-14	1,186	1,057	0.8	91.89	6.3	12,977	LIGHT OIL	2,353	BBLS	5.83	13,715	258,662	24.47
24	SUWANNEE CT	1-3	200	117	0.9	83.87	58.3	13,457	LIGHT OIL	269	BBLS	5.83	1,568	27,297	23.43
25	OTHER - START UP	0	-	0	-	0.00	0.0	0	LIGHT OIL	1,425	BBLS	5.83	8,300	126,276	0.00
26	SOLAR	1	513	100,339	26.3	0.00	52.6	0	SOLAR	0	N/A		0	0	0.00
27	TOTAL			3,480,414									26,469,606	99,760,893	2.87

Duke Energy Florida, LLC
System Net Generation and Fuel Cost
Estimated for the Period of: Nov-21

	(A) PLANT/UNIT		(B) NET CAPACITY (MW)	(C) NET GENERATION (MWH)	(D) CAPACITY FACTOR (%)	(E) EQUIV AVA L FACTOR (%)	(F) OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE (BTU/KWH)	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)		(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MMBTU)	(L) AS BURNED FUEL COST ($)	(M) FUEL COST PER KWH (C/KWH)
1	CRYSTAL RIVER	4	732	326,786	62.0	97 00	65.7	10,261	COAL	145,041	TONS	23.12	3,353,227	8,988,356	2.75
2	CRYSTAL RIVER	5	712	252,455	49.2	95 33	58 3	10,205	COAL	111,436	TONS	23.12	2,576,306	6,931,796	2.75
3	ANCLOTE	1	517	17,435	4.7	92 00	21 3	11,698	GAS	203,962	MCF	1.00	203,962	1,127,562	6.47
4	ANCLOTE	2	521	33,490	8.9	100 00	24 6	12,077	GAS	404,473	MCF	1.00	404,473	1,651,700	4.93
5	AVON PARK	1-2	228	0	0.0	0 00	0 0	0	GAS	0	MCF	0.00	0	0	0.00
6	BARTOW	1-4	1,279	98	0.0	87 25	2.4	15,718	GAS	1,534	MCF	1.00	1,534	7,008	7.18
7	BARTOWCC	1	1279	444,173	48.2	61 36	50.1	7,350	GAS	3,264,604	MCF	1.00	3,264,604	14,912,332	3.36
8	CITRUS CC	1-2	1640	679,304	57.5	60.17	92.7	6,538	GAS	4,440,954	MCF	1.00	4,440,954	20,285,762	2.99
9	DEBARY	1-10	785	2,555	0.6	80 67	9 2	12,682	GAS	32,396	MCF	1.00	32,396	147,981	5.79
10	HINES	1-4	2,204	784,382	49.5	80.40	85.7	7,026	GAS	5,511,450	MCF	1.00	5,511,450	25,175,666	3.21
11	INT CITY	1-14	1,186	2,776	0.4	86 84	6 3	12,606	GAS	34,994	MCF	1.00	34,994	159,854	5.76
12	OSPREY	1	505	91,591	25.2	97.46	66 9	7,632	GAS	699,022	MCF	1.00	699,022	3,193,051	3.49
13	SUWANNEE CT	1-3	200	740	0.6	77 61	22.1	13,812	GAS	10,215	MCF	1.00	10,215	46,664	6.31
14	TIGER BAY	1	225	36,456	22.5	92 33	86 6	7,677	GAS	279,879	MCF	1.00	279,879	1,278,456	3.51
15	UNIV OF FLA.	1	47	30,031	88.7	97 00	91 5	9,377	GAS	281,609	MCF	1.00	281,609	1,314,518	4.38
16	AVON PARK	1-2	69	0	0.0	0 00	0 0	0	LIGHT O L	0	BBLS		0	0	0.00
17	BARTOW	1-4	228	183	0.2	87 25	13.7	16,077	LIGHT O L	505	BBLS	5.84	2,947	57,317	31.27
18	BARTOW CC	1	1,279	0	48.2	61 36	50.1	0	LIGHT O L	0	BBLS	5.84	0	0	0.00
19	BAYBORO	1-4	231	163	0.1	94 67	17 6	14,834	LIGHT O L	414	BBLS	5.84	2,415	57,520	35.33
20	DEBARY	1-10	785	779	0.6	80 67	9 2	12,947	LIGHT O L	1,732	BBLS	5.84	10,089	215,801	27.69
21	HINESCC	1-4	2,204	1,708	49.5	80.40	85.7	7,106	LIGHT O L	2,083	BBLS	5.84	12,137	179,885	10.53
22	OTHER		0	0	0.0	0 00	0 0	0	LIGHT O L	0	BBLS	5.84	0	0	0.00
23	INT CITY	1-14	1,186	1,054	0.4	86 84	6 3	12,720	LIGHT O L	2,303	BBLS	5.84	13,407	253,429	24.04
24	SUWANNEE CT	1-3	200	100	0.6	77 61	50.1	13,849	LIGHT O L	239	BBLS	5.84	1,387	24,450	24.41
25	OTHER - START UP	0	-	0	-	0 00	0 0	0	LIGHT O L	285	BBLS	5.84	1,660	31,982	0.00
26	SOLAR	1	513	85,579	23.2	0 00	51 0	0	SOLAR	0	N/A		0	0	0.00
27	TOTAL			2,791,837									21,138,667	86,041,090	3.08

Duke Energy Florida, LLC
System Net Generation and Fuel Cost
Estimated for the Period of: Dec-21

	(A)		(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
	PLANT/UNIT		NET CAPACITY (MW)	NET GENERATION (MWH)	CAPACITY FACTOR (%)	EQUIV AVAIL FACTOR (%)	OUTPUT FACTOR (%)	AVG. NET HEAT RATE (BTU/KWH)	FUEL TYPE	FUEL BURNED (UNITS)	FUEL HEAT VALUE (BTU/UNIT)	FUEL BURNED (MMBTU)	AS BURNED FUEL COST ($)	FUEL COST PER KWH (C/KWH)
1	CRYSTAL RIVER	4	732	165,959	30.5	91 94	56.4	10,437	COAL	74,908 TONS	23.12	1,732,062	4,713,819	2 84
2	CRYSTAL RIVER	5	712	180,871	34.1	93 55	52 5	10,290	COAL	80,495 TONS	23.12	1,861,234	5,056,996	2 80
3	ANCLOTE	1	517	1,130	0.3	96.77	16 8	12,059	GAS	13,625 MCF	1.00	13,625	111,604	9 88
4	ANCLOTE	2	521	5,031	1.3	98 06	20.1	13,467	GAS	67,746 MCF	1.00	67,746	260,381	5.18
5	AVON PARK	1-2	228	0	0.0	0 00	0 0	0	GAS	0 MCF	0.00	0	0	0 00
6	BARTOW	1-4	1,279	106	0.0	87 34	2.7	15,255	GAS	1,617 MCF	1.00	1,617	7,394	6 98
7	BARTOWCC	1	1279	627,164	65.9	94 84	69 6	6,951	GAS	4,359,549 MCF	1.00	4,359,549	19,929,496	3.18
8	CITRUS CC	1-2	1640	1,196,178	98.0	95 00	103 8	6,502	GAS	7,777,678 MCF	1.00	7,777,678	35,555,324	2 97
9	DEBARY	1-10	785	559	0.3	80 07	9 0	13,134	GAS	7,337 MCF	1.00	7,337	33,542	6 00
10	HINES	1-4	2,204	595,873	36.4	94.76	87 9	7,024	GAS	4,185,292 MCF	1.00	4,185,292	19,132,883	3 21
11	NT CITY	1-14	1,186	1,442	0.4	93 00	6 5	13,182	GAS	19,013 MCF	1.00	19,013	86,913	6 03
12	OSPREY	1	505	13,420	3.6	95 28	69 9	7,927	GAS	106,387 MCF	1.00	106,387	486,343	3 62
13	SUWANNEE CT	1-3	200	1,879	1.4	85.17	22 5	14,266	GAS	26,810 MCF	1.00	26,810	122,558	6 52
14	TIGER BAY	1	225	1,245	0.7	93 55	110.7	7,556	GAS	9,410 MCF	1.00	9,410	43,015	3.45
15	UNIV OF FLA.	1	47	30,444	87.1	95.16	91 5	9,383	GAS	285,650 MCF	1.00	285,650	1,334,400	4 38
16	AVON PARK	1-2	69	0	0.0	0 00	0 0	0	LIGHT OIL	0 BBLS		0	0	0 00
17	BARTOW	1-4	228	202	0.2	87 34	15 0	15,297	LIGHT OIL	531 BBLS	5.82	3,090	59,880	29 64
18	BARTOW CC	1	1,279	0	65.9	94 84	69 6	0	LIGHT OIL	0 BBLS	5.82	0	0	0 00
19	BAYBORO	1-4	231	223	0.1	92.42	24 2	13,344	LIGHT OIL	512 BBLS	5.82	2,981	69,449	31 09
20	DEBARY	1-10	785	994	0.3	80 07	9 0	13,008	LIGHT OIL	2,218 BBLS	5.82	12,928	271,493	27 32
21	HINESCC	1-4	2,204	1,689	36.4	94.76	87 9	7,247	LIGHT OIL	2,101 BBLS	5.82	12,242	181,309	10.73
22	OTHER		0	0	0.0	0 00	0 0	0	LIGHT OIL	0 BBLS	5.82	0	0	0 00
23	NT CITY	1-14	1,186	1,725	0.4	93 00	6 5	12,724	LIGHT OIL	3,769 BBLS	5.82	21,953	398,315	23 09
24	SUWANNEE CT	1-3	200	147	1.4	85.17	73 3	13,628	LIGHT OIL	344 BBLS	5.82	1,999	34,123	23 26
25	OTHER - START UP	0	-	0	-	0 00	0 0	0	LIGHT OIL	285 BBLS	5.82	1,660	31,740	0 00
26	SOLAR	1	738	72,147	13.1	0 00	28.7	0	SOLAR	0 N/A		0	0	0 00
27	TOTAL			2,898,430								20,510,263	87,920,977	3 03

Duke Energy Florida, LLC
Inventory Analysis
Estimated for the Period of : January 2021 through December 2021

			Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Subtotal
	LIGHT OIL								
1	PURCHASES:								
2	UNITS	BBL	9,131	8,349	6,337	4,526	8,256	9,065	45,664
3	UNIT COST	$/BBL	111.12	115.41	120.35	126.94	113.13	107.66	114.43
4	AMOUNT	$	1,014,622	963,575	762,635	574,512	934,006	975,912	5,225,262
5	BURNED:								
6	UNITS	BBL	9,131	8,349	6,337	4,526	8,256	9,065	45,664
7	UNIT COST	$/BBL	111.12	115.41	120.35	126.94	113.13	107.66	114.43
8	AMOUNT	$	1,014,622	963,575	762,635	574,512	934,006	975,912	5,225,262
9	ENDING INVENTORY:								
10	UNITS	BBL	586,874	586,874	586,874	586,874	586,874	586,874	
11	UNIT COST	$/BBL	108.36	108.36	108.36	108.36	108.36	108.36	
12	AMOUNT	$	63,592,212	63,592,212	63,592,212	63,592,212	63,592,212	63,592,212	
	COAL								
13	PURCHASES:								
14	UNITS	TON	277,702	231,478	286,538	137,253	253,295	278,254	1,464,520
15	UNIT COST	$/TON	70.09	67.53	65.03	65.47	63.65	62.74	65.75
16	AMOUNT	$	19,463,507	15,630,604	18,634,230	8,986,470	16,121,450	17,457,382	96,293,643
17	BURNED:								
18	UNITS	TON	277,702	231,478	286,538	137,253	253,295	278,254	1,464,520
19	UNIT COST	$/TON	70.09	67.53	65.03	65.47	63.65	62.74	65.75
20	AMOUNT	$	19,463,507	15,630,604	18,634,230	8,986,470	16,121,450	17,457,382	96,293,643
21	ENDING INVENTORY:								
22	UNITS	TON	520,729	520,729	520,729	520,729	520,729	520,729	
23	UNIT COST	$/TON	86.03	86.03	86.03	86.03	86.03	86.03	
24	AMOUNT	$	44,798,943	44,798,943	44,798,943	44,798,943	44,798,943	44,798,943	
	GAS								
25	BURNED:								
26	UNITS	MCF	15,295,843	13,729,739	14,439,048	17,969,518	21,297,765	23,882,959	106,614,872
27	UNIT COST	$/MCF	4.99	4.98	4.97	4.19	4.07	3.89	4.42
28	AMOUNT	$	76,394,273	68,441,822	71,736,796	75,222,711	86,746,429	92,999,907	471,541,938

Duke Energy Florida, LLC
Inventory Analysis
Estimated for the Period of : January 2021 through December 2021

			Jul-21	Aug-21	Sep-21	Oct-21	Nov-21	Dec-21	Total
	LIGHT OIL								
1	PURCHASES:								
2	UNITS	BBL	9,067	8,892	9,301	8,586	7,561	9,760	98,831
3	UNIT COST	$/BBL	107.40	106.30	105.94	104.32	108.50	107.20	110.21
4	AMOUNT	$	973,781	945,198	985,311	895,692	820,384	1,046,309	10,891,937
5	BURNED:								
6	UNITS	BBL	9,067	8,892	9,301	8,586	7,561	9,760	98,831
7	UNIT COST	$/BBL	107.40	106.30	105.94	104.32	108.50	107.20	110.21
8	AMOUNT	$	973,781	945,198	985,311	895,692	820,384	1,046,309	10,891,937
9	ENDING INVENTORY:								
10	UNITS	BBL	586,874	586,874	586,874	586,874	586,874	586,874	
11	UNIT COST	$/BBL	108.36	108.36	108.36	108.36	108.36	108.36	
12	AMOUNT	$	63,592,212	63,592,212	63,592,212	63,592,212	63,592,212	63,592,212	
	COAL								
13	PURCHASES:								
14	UNITS	TON	288,966	285,808	254,790	258,453	256,477	155,403	2,964,417
15	UNIT COST	$/TON	62.34	62.12	62.14	62.10	62.07	62.87	63.97
16	AMOUNT	$	18,015,119	17,754,298	15,831,804	16,049,666	15,920,152	9,770,815	189,635,497
17	BURNED:								
18	UNITS	TON	288,966	285,808	254,790	258,453	256,477	155,403	2,964,417
19	UNIT COST	$/TON	62.34	62.12	62.14	62.10	62.07	62.87	63.97
20	AMOUNT	$	18,015,119	17,754,298	15,831,804	16,049,666	15,920,152	9,770,815	189,635,497
21	ENDING INVENTORY:								
22	UNITS	TON	520,729	520,729	520,729	520,729	520,729	520,729	
23	UNIT COST	$/TON	86.03	86.03	86.03	86.03	86.03	86.03	
24	AMOUNT	$	44,798,943	44,798,943	44,798,943	44,798,943	44,798,943	44,798,943	
	GAS								
25	BURNED:								
26	UNITS	MCF	25,743,204	25,456,440	24,330,828	20,443,016	15,165,092	16,860,114	234,613,566
27	UNIT COST	$/MCF	3.87	3.89	3.90	4.05	4.57	4.57	4.24
28	AMOUNT	$	99,681,209	99,145,911	94,876,901	82,815,535	69,300,554	77,103,853	994,465,901

Duke Energy Florida, LLC
Fuel Cost of Power Sold
Estimated for the Period of : January 2021 through December 2021

(1)	(2)	(3)	(4)	(5)	(6)	(7)		(8)	(9)	(10)
MONTH	SOLD TO	TYPE & SCHED	TOTAL MWH SOLD	MWH WHEELED FROM OTHER SYSTEMS	MWH FROM OWN GENERATION	C/KWH (A) FUEL COST	C/KWH (B) TOTAL COST	TOTAL $ FOR FUEL ADJ (6) x (7)(A)	TOTAL COST $ (6) x (7)(B)	REFUNDABLE GAIN ON POWER SALES $
Jan-21	ECONSALE	--	40,054		40,054	3.540	4.437	1,417,816	1,777,332	359,516
	ECONOMY	C	0		0	0.000	0.000	0	0	0
	EXCESS GAIN	--	0		0	0.000	0.000	0	0	0
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	STRATIFIED	--	76,602		76,602	2.319	2.319	1,776,625	1,776,625	0
	TOTAL		116,656		116,656	2.738	3.047	3,194,441	3,553,957	359,516
Feb-21	ECONSALE	--	22,218		22,218	3.241	4.062	720,014	902,588	182,574
	ECONOMY	C	0		0	0.000	0.000	0	0	0
	EXCESS GAIN	--	0		0	0.000	0.000	0	0	0
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	STRATIFIED	--	79,322		79,322	2.296	2.296	1,821,495	1,821,495	0
	TOTAL		101,540		101,540	2.503	2.683	2,541,509	2,724,083	182,574
Mar-21	ECONSALE	--	12,357		12,357	3.019	3.785	373,060	467,657	94,597
	ECONOMY	C	0		0	0.000	0.000	0	0	0
	EXCESS GAIN	--	0		0	0.000	0.000	0	0	0
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	STRATIFIED	--	114,533		114,533	2.210	2.210	2,531,345	2,531,345	0
	TOTAL		126,889		126,889	2.289	2.363	2,904,405	2,999,002	94,597
Apr-21	ECONSALE	--	5,557		5,557	3.179	3.985	176,655	221,449	44,794
	ECONOMY	C	0		0	0.000	0.000	0	0	0
	EXCESS GAIN	--	0		0	0.000	0.000	0	0	0
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	STRATIFIED	--	109,592		109,592	1.943	1.943	2,129,343	2,129,343	0
	TOTAL		115,148		115,148	2.003	2.042	2,305,998	2,350,792	44,794
May-21	ECONSALE	--	15,079		15,079	3.609	4.524	544,153	682,134	137,981
	ECONOMY	C	0		0	0.000	0.000	0	0	0
	EXCESS GAIN	--	0		0	0.000	0.000	0	0	0
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	STRATIFIED	--	198,008		198,008	1.925	1.925	3,811,913	3,811,913	0
	TOTAL		213,087		213,087	2.044	2.109	4,356,066	4,494,047	137,981
Jun-21	ECONSALE	--	18,305		18,305	3.724	4.668	681,635	854,477	172,842
	ECONOMY	C	0		0	0.000	0.000	0	0	0
	EXCESS GAIN	--	0		0	0.000	0.000	0	0	0
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	STRATIFIED	--	201,835		201,835	2.053	2.053	4,142,776	4,142,776	0
	TOTAL		220,140		220,140	2.192	2.270	4,824,411	4,997,253	172,842
Jan	ECONSALE	--	113,569		113,569	3.446	4.320	3,913,333	4,905,637	992,304
THRU	ECONOMY	C	0		0	0.000	0.000	0	0	0
Jun-21	EXCESS GAIN	--	0		0	0.000	0.000	0	0	0
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	STRATIFIED	--	779,892		779,892	2078.941	2078.941	16,213,498	16,213,498	0
	TOTAL		893,462		893,462	2.253	2.364	20,126,831	21,119,135	992,304

Duke Energy Florida, LLC
Fuel Cost of Power Sold
Estimated for the Period of : January 2021 through December 2021

(1)	(2)	(3)	(4)	(5)	(6)	(7)		(8)	(9)	(10)
				MWH		C/KWH				REFUNDABLE
MONTH	SOLD TO	TYPE & SCHED	TOTAL MWH SOLD	WHEELED FROM OTHER SYSTEMS	MWH FROM OWN GENERATION	(A) FUEL COST	(B) TOTAL COST	TOTAL $ FOR FUEL ADJ (6) x (7)(A)	TOTAL COST $ (6) x (7)(B)	GAIN ON POWER SALES $
Jul-21	ECONSALE	--	24,319		24,319	3.675	4.607	893,679	1,120,290	226,611
	ECONOMY	C	0		0	0.000	0.000	0	0	0
	EXCESS GAIN	--	0		0	0.000	0.000	0	0	0
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	STRATIFIED	--	183,676		183,676	2.104	2.104	3,865,308	3,865,308	0
	TOTAL		207,996		207,996	2.288	2.397	4,758,987	4,985,598	226,611
Aug-21	ECONSALE	--	21,926		21,926	4.125	5.171	904,456	1,133,800	229,344
	ECONOMY	C	0		0	0.000	0.000	0	0	0
	EXCESS GAIN	--	0		0	0.000	0.000	0	0	0
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	STRATIFIED	--	187,796		187,796	2.108	2.108	3,958,110	3,958,110	0
	TOTAL		209,722		209,722	2.319	2.428	4,862,566	5,091,910	229,344
Sep-21	ECONSALE	--	20,871		20,871	3.743	4.692	781,122	979,191	198,069
	ECONOMY	C	0		0	0.000	0.000	0	0	0
	EXCESS GAIN	--	0		0	0.000	0.000	0	0	0
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	STRATIFIED	--	195,683		195,683	2.084	2.084	4,079,003	4,079,003	0
	TOTAL		216,554		216,554	2.244	2.336	4,860,125	5,058,194	198,069
Oct-21	ECONSALE	--	9,653		9,653	3.452	4.328	333,265	417,772	84,507
	ECONOMY	C	0		0	0.000	0.000	0	0	0
	EXCESS GAIN	--	0		0	0.000	0.000	0	0	0
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	STRATIFIED	--	186,530		186,530	2.106	2.106	3,927,876	3,927,876	0
	TOTAL		196,183		196,183	2.172	2.215	4,261,141	4,345,648	84,507
Nov-21	ECONSALE	--	11,767		11,767	3.476	4.357	408,971	512,674	103,703
	ECONOMY	C	0		0	0.000	0.000	0	0	0
	EXCESS GAIN	--	0		0	0.000	0.000	0	0	0
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	STRATIFIED	--	120,393		120,393	2.262	2.262	2,723,855	2,723,855	0
	TOTAL		132,160		132,160	2.370	2.449	3,132,826	3,236,529	103,703
Dec-21	ECONSALE	--	11,575		11,575	2.915	3.654	337,410	422,967	85,557
	ECONOMY	C	0		0	0.000	0.000	0	0	0
	EXCESS GAIN	--	0		0	0.000	0.000	0	(47,511)	(47,511)
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	STRATIFIED	--	81,709		81,709	2.552	2.552	2,084,968	2,084,968	0
	TOTAL		93,284		93,284	2.597	2.638	2,422,378	2,460,424	38,046
Jan-21	ECONSALE	--	213,680		213,680	3.544	4.442	7,572,236	9,492,331	1,920,095
THRU	ECONOMY	C	0		0	0.000	0.000	0	0	0
Dec-21	EXCESS GAIN	--	0		0	0.000	0.000	0	(47,511)	(47,511)
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	STRATIFIED	--	1,735,681		1,735,681	2.123	2.123	36,852,618	36,852,618	0
	TOTAL		1,949,360		1,949,360	2.279	2.375	44,424,854	46,297,438	1,872,584

Duke Energy Florida, LLC
Purchased Power
(Exclusive of Economy & QF Purchases)
Estimated for the Period of : January 2021 through December 2021

(1) MONTH	(2) NAME OF PURCHASE	(3) TYPE & SCHEDULE	(4) TOTAL MWH PURCHASED	(5) MWH FOR OTHER UTILITIES	(6) MWH FOR INTERRUPTIBLE	(7) MWH FOR FIRM	(8) C/KWH (A) FUEL COST	(8) C/KWH (B) TOTAL COST	(9) TOTAL $ FOR FUEL ADJ (7) x (8)(B)
Jan-21	OTHER	--	0			0	0.000	0.000	0
	SHADY HILLS	--	190			190	8.084	8.084	15,383
	SOCO Franklin	--	9,938			9,938	3.393	3.393	337,227
	Vandolah (NSG)	--	1,683			1,683	9.339	9.339	157,202
	TOTAL		11,812	0	0	11,812	4.316	4.316	509,812
Feb-21	OTHER	--	0			0	0.000	0.000	0
	SHADY HILLS	--	0			0	0.000	0.000	3,576
	SOCO Franklin	--	5,749			5,749	3.752	3.752	215,691
	Vandolah (NSG)	--	189			189	31.648	31.648	59,783
	TOTAL		5,938	0	0	5,938	4.699	4.699	279,050
Mar-21	OTHER	--	0			0	0.000	0.000	0
	SHADY HILLS	--	0			0	0.000	0.000	3,576
	SOCO Franklin	--	13,757			13,757	3.396	3.396	467,225
	Vandolah (NSG)	--	140			140	38.718	38.718	54,321
	TOTAL		13,897	0	0	13,897	3.779	3.779	525,122
Apr-21	OTHER	--	0			0	0.000	0.000	0
	SHADY HILLS	--	1,050			1,050	5.106	5.106	53,610
	SOCO Franklin	--	22,343			22,343	2.698	2.698	602,847
	Vandolah (NSG)	--	3,242			3,242	6.475	6.475	209,921
	TOTAL		26,635	0	0	26,635	3.253	3.253	866,378
May-21	OTHER	--	0			0	0.000	0.000	0
	SHADY HILLS	--	8,875			8,875	6.614	6.614	586,986
	SOCO Franklin	--	38,590			38,590	2.742	2.742	1,058,226
	Vandolah (NSG)	--	7,479			7,479	9.106	9.106	681,103
	TOTAL		54,945	0	0	54,945	4.234	4.234	2,326,315
Jun-21	OTHER	--	0			0	0.000	0.000	0
	SHADY HILLS	--	2,247			2,247	4.594	4.594	103,210
	SOCO Franklin	--	0			0	0.000	0.000	0
	Vandolah (NSG)	--	8,722			8,722	5.225	5.225	455,700
	TOTAL		10,969	0	0	10,969	5.096	5.096	558,910
Jan-21	OTHER	--	0			0	0.000	0.000	0
THRU	SHADY HILLS	--	12,362			12,362	6.199	6.199	766,341
Jun-21	SOCO Franklin	--	90,377			90,377	2.967	2.967	2,681,216
	Vandolah (NSG)	--	21,455			21,455	7.541	7.541	1,618,030
	TOTAL		124,195	0	0	124,195	4.079	4.079	5,065,587

Duke Energy Florida, LLC
Purchased Power
(Exclusive of Economy & QF Purchases)
Estimated for the Period of : January 2021 through December 2021

(1) MONTH	(2) NAME OF PURCHASE	(3) TYPE & SCHEDULE	(4) TOTAL MWH PURCHASED	(5) MWH FOR OTHER UTILITIES	(6) MWH FOR INTERRUPTIBLE	(7) MWH FOR FIRM	(8) C/KWH (A) FUEL COST	(8) C/KWH (B) TOTAL COST	(9) TOTAL $ FOR FUEL ADJ (7) x (8)(B)
Jul-21	OTHER	--	0			0	0.000	0.000	0
	SHADY HILLS	--	8,962			8,962	4.334	4.334	388,348
	SOCO Franklin	--	0			0	0.000	0.000	0
	Vandolah (NSG)	--	15,691			15,691	4.939	4.939	774,916
	TOTAL		24,653	0	0	24,653	4.719	4.719	1,163,264
Aug-21	OTHER	--	0			0	0.000	0.000	0
	SHADY HILLS	--	9,797			9,797	4.446	4.446	435,617
	SOCO Franklin	--	0			0	0.000	0.000	0
	Vandolah (NSG)	--	9,579			9,579	5.326	5.326	510,160
	TOTAL		19,376	0	0	19,376	4.881	4.881	945,777
Sep-21	OTHER	--	0			0	0.000	0.000	0
	SHADY HILLS	--	2,862			2,862	4.498	4.498	128,736
	SOCO Franklin	--	0			0	0.000	0.000	0
	Vandolah (NSG)	--	3,986			3,986	5.821	5.821	232,041
	TOTAL		6,848	0	0	6,848	5.268	5.268	360,777
Oct-21	OTHER	--	0			0	0.000	0.000	0
	SHADY HILLS	--	10,966			10,966	4.511	4.511	494,715
	SOCO Franklin	--	0			0	0.000	0.000	0
	Vandolah (NSG)	--	6,692			6,692	5.404	5.404	361,644
	TOTAL		17,658	0	0	17,658	4.850	4.850	856,359
Nov-21	OTHER	--	0			0	0.000	0.000	0
	SHADY HILLS	--	2,496			2,496	13.246	13.246	330,614
	SOCO Franklin	--	0			0	0.000	0.000	0
	Vandolah (NSG)	--	4,448			4,448	12.640	12.640	562,234
	TOTAL		6,944	0	0	6,944	12.858	12.858	892,848
Dec-21	OTHER	--	0			0	0.000	0.000	0
	SHADY HILLS	--	0			0	0.000	0.000	3,576
	SOCO Franklin	--	0			0	0.000	0.000	0
	Vandolah (NSG)	--	0			0	0.000	0.000	45,424
	TOTAL		0	0	0	0	0.000	0.000	49,000
Jan-21	OTHER	--	0			0	0.000	0.000	0
THRU	SHADY HILLS	--	47,446			47,446	5.370	5.370	2,547,947
Dec-21	SOCO Franklin	--	90,377			90,377	2.967	2.967	2,681,216
	Vandolah (NSG)	--	61,852			61,852	6.636	6.636	4,104,449
TOTAL			199,674	0	0	199,674	4.674	4.674	9,333,612

Duke Energy Florida, LLC
Energy Payments to Qualifying Facilities
Estimated for the Period of : January 2021 through December 2021

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)		(9)
				MWH			C/KWH		TOTAL $
MONTH	NAME OF PURCHASE	TYPE & SCHEDULE	TOTAL MWH PURCHASED	FOR OTHER UTILITIES	MWH FOR INTERRUPTIBLE	MWH FOR FIRM	(A) ENERGY COST	(B) TOTAL COST	FOR FUEL ADJ (7) x (8)(A)
Jan-21	QUAL. FACILITIES	COGEN	252,015			252,015	3.656	15.018	9,212,857
Feb-21	QUAL. FACILITIES	COGEN	208,275			208,275	3.622	17.370	7,542,954
Mar-21	QUAL. FACILITIES	COGEN	217,338			217,338	3.783	16.959	8,222,147
Apr-21	QUAL. FACILITIES	COGEN	221,208			221,208	3.627	16.572	8,022,798
May-21	QUAL. FACILITIES	COGEN	249,501			249,501	3.715	15.192	9,269,427
Jun-21	QUAL. FACILITIES	COGEN	239,975			239,975	3.760	15.692	9,022,105
Jul-21	QUAL. FACILITIES	COGEN	247,418			247,418	3.776	15.350	9,343,453
Aug-21	QUAL. FACILITIES	COGEN	247,272			247,272	3.768	15.348	9,316,324
Sep-21	QUAL. FACILITIES	COGEN	239,123			239,123	3.753	15.728	8,974,034
Oct-21	QUAL. FACILITIES	COGEN	233,657			233,657	3.830	16.085	8,949,021
Nov-21	QUAL. FACILITIES	COGEN	239,214			239,214	3.699	15.669	8,848,146
Dec-21	QUAL. FACILITIES	COGEN	271,792			271,792	3.551	14.087	9,652,457
TOTAL	QUAL. FACILITIES	COGEN	2,866,788			2,866,788	3.711	15.697	106,375,724

Duke Energy Florida, LLC
Economy Energy Purchases
Estimated for the Period of : January 2021 through December 2021

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)		(9)
				TRANSACTION COST		TOTAL $	COST IF GENERATED		
MONTH	PURCHASE	TYPE & SCHED	TOTAL MWH PURCHASED	ENERGY COST C/KWH	TOTAL COST C/KWH	FOR FUEL ADJ (4) x (5)	(A) C/KWH	(B) $	FUEL SAVINGS (8)(B) - (7)
Jan-21	ECONPURCH	--	1,968	4.029	4.029	79,297	4.519	88,957	9,660
	SEPA	--	0	0.000	0.000	0	0.000	0	-
	TOTAL		1,968	4.029	4.029	79,297	4.519	88,957	9,660
Feb-21	ECONPURCH	--	2,486	3.839	3.839	95,430	4.307	107,063	11,633
	SEPA	--	0	0.000	0.000	0	0.000	0	-
	TOTAL		2,486	3.839	3.839	95,430	4.307	107,063	11,633
Mar-21	ECONPURCH	--	4,188	3.704	3.704	155,108	4.155	174,022	18,914
	SEPA	--	0	0.000	0.000	0	0.000	0	-
	TOTAL		4,188	3.704	3.704	155,108	4.155	174,022	18,914
Apr-21	ECONPURCH	--	4,069	3.668	3.668	149,250	4.115	167,446	18,196
	SEPA	--	0	0.000	0.000	0	0.000	0	-
	TOTAL		4,069	3.668	3.668	149,250	4.115	167,446	18,196
May-21	ECONPURCH	--	4,544	4.277	4.277	194,346	4.799	218,045	23,699
	SEPA	--	0	0.000	0.000	0	0.000	0	-
	TOTAL		4,544	4.277	4.277	194,346	4.799	218,045	23,699
Jun-21	ECONPURCH	--	4,573	4.486	4.486	205,130	5.033	230,145	25,015
	SEPA	--	0	0.000	0.000	0	0.000	0	-
	TOTAL		4,573	4.486	4.486	205,130	5.033	230,145	25,015
Jan-21	ECONPURCH	--	21,828	4.025	4.025	878,561	4.516	985,678	107,117
THRU	SEPA	--	0	0.000	0.000	0	-	0	-
Jun-21									
	TOTAL		21,828	4.025	4.025	878,561	4.516	985,678	107,117

Duke Energy Florida, LLC
Economy Energy Purchases
Estimated for the Period of : January 2021 through December 2021

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)		(9)
				TRANSACTION COST		TOTAL $	COST IF GENERATED		
MONTH	PURCHASE	TYPE & SCHED	TOTAL MWH PURCHASED	ENERGY COST C/KWH	TOTAL COST C/KWH	FOR FUEL ADJ (4) x (5)	(A) C/KWH	(B) $	FUEL SAVINGS (8)(B) - (7)
Jul-21	ECONPURCH	--	2,449	4.540	4.540	111,190	5.094	124,749	13,559
	SEPA	--	0	0.000	0.000	0	0.000	0	-
	TOTAL		2,449	4.540	4.540	111,190	5.094	124,749	13,559
Aug-21	ECONPURCH	--	2,195	4.486	4.486	98,450	5.033	110,455	12,005
	SEPA	--	0	0.000	0.000	0	0.000	0	-
	TOTAL		2,195	4.486	4.486	98,450	5.033	110,455	12,005
Sep-21	ECONPURCH	--	1,472	4.649	4.649	68,453	5.216	76,801	8,348
	SEPA	--	0	0.000	0.000	0	0.000	0	-
	TOTAL		1,472	4.649	4.649	68,453	5.216	76,801	8,348
Oct-21	ECONPURCH	--	2,213	4.087	4.087	90,445	4.585	101,478	11,033
	SEPA	--	0	0.000	0.000	0	0.000	0	-
	TOTAL		2,213	4.087	4.087	90,445	4.585	101,478	11,033
Nov-21	ECONPURCH	--	3,935	3.705	3.705	145,770	4.156	163,546	17,776
	SEPA	--	0	0.000	0.000	0	0.000	0	-
	TOTAL		3,935	3.705	3.705	145,770	4.156	163,546	17,776
Dec-21	ECONPURCH	--	4,111	3.563	3.563	146,484	3.998	164,351	17,867
	SEPA	--	0	0.000	0.000	0	0.000	0	-
	TOTAL		4,111	3.563	3.563	146,484	3.998	164,351	17,867
Jan-21	ECONPURCH	--	38,203	4.029	4.029	1,539,353	4.521	1,727,058	187,705
THRU	SEPA	--	0	0.000	0.000	0	0.000	0	-
Dec-21									
	TOTAL		38,203	4.029	4.029	1,539,353	4.521	1,727,058	187,705

Duke Energy Florida, LLC
Fuel and Purchased Power Cost Recovery Clause
Residential Bill Comparison

	Current Sep-Dec - 2020 ($/1000 kWh)	Requested Jan-2021 [1] ($/1000 kWh)	Difference from Current $	%
Base Rate [1]	$72.30	$74.11	$1.81	2.50%
Fuel Cost Recovery	30.67	28.11	(2.56)	-8.35%
Capacity Cost Recovery (CCR)	12.00	14.05	2.05	17.08%
Energy Conservation Cost Recovery (ECCR)	3.39	3.38	(0.01)	-0.29%
Environmental Cost Recovery (ECRC)	0.79	0.99	0.20	25.32%
Storm Protection Plan Cost Recovery Charge (SPPCRC)	0.00	0.31	0.31	100.00%
Interim Storm Charge [2]	5.34	0.00	(5.34)	-100.00%
Asset Securitization Charge (ASC)	2.51	2.51	0.00	0.00%
Subtotal	127.00	123.46	(3.54)	-2.79%
Gross Receipts Tax	3.26	3.17	(0.09)	-2.76%
Total	$130.26	$126.63	($3.63)	-2.79%

[1] The January 2021 Base Rate includes proposed adjustments for the Columbia Solar Power Plant Project True-Up (SoBRA I), DeBary, Lake Placid and Trenton Solar Power Plant Projects (SoBRA II), and Multi-Year Base Rate Increase filed in Docket No. 20190072 and 20180149.

[2] Per Order No. PSC-2020-0058-PCO-EI, DEF is authorized to collect Hurricane Dorian and TS Nestor costs through the Interim Storm Charge beginning in March 2020 and ending the earlier of full recovery or with the last billing cycle for February 2021. Based on current estimates, DEF expects to be able to stop the charge beginning in January 2021. This could change based on changes in sales over the remainder of 2020.

Duke Energy Florida, LLC
Fuel and Purchased Power Cost Recovery Clause
Calculation of Inverted Residential Fuel Factors

	Annual Units mWh	Levelized Fuel Rate Cents/kWh	Annual Fuel Revenues	Inverted Fuel Rates Cents/kWh	Annual Fuel Revenues
Residential Excluding TOU:					
0 - 1,000 kWh	15,161,530	3.094	$ 469,097,733	2.811	$ 426,212,683
Over 1,000 kWh	5,979,964	3.094	185,020,082	3.811	227,905,132
Total	21,141,494		$ 654,117,815		$ 654,117,815
Rate Differential by Tier - Cents per kWh				1.000	

Residential Sales:	
Total	21,141,521
Time of Use	27
Levelized	21,141,494

Duke Energy Florida, LLC
Fuel and Purchased Power Cost Recovery Clause
Generating System Comparative Data by Fuel Type

		2018 Actual	2019 Actual	2020 Actual/Estimated	2021 Projection	2019 vs. 2018	2020 vs. 2019	2021 vs. 2020
FUEL COST OF SYSTEM NET GENERATION ($)								
LIGHT OIL		22,609,544	14,226,223	10,339,922	10,891,937	-58.9%	-37.6%	5.3%
COAL		276,175,645	161,620,864	127,810,084	189,635,497	-70.9%	-26.5%	48.4%
GAS		1,023,687,201	1,055,035,576	886,739,700	994,465,901	3.0%	-19.0%	12.1%
OTHER		0	0	0	0	0.0%	0.0%	0.0%
TOTAL	$	1,322,472,390	1,230,882,664	1,024,889,706	1,194,993,335	-7.4%	-20.1%	16.6%
SYSTEM NET GENERATION (mWh)								
LIGHT OIL		90,434	52,512	27,842	45,777	-72.2%	-88.6%	64.4%
COAL		8,421,960	4,300,231	3,286,481	6,644,108	-95.8%	-30.8%	102.2%
GAS		28,686,945	35,165,359	35,955,476	32,962,583	18.4%	2.2%	-8.3%
SOLAR		25,744	214,679	760,622	1,270,597	88.0%	71.8%	67.0%
OTHER		0	0	0	0	0.0%	0.0%	0.0%
TOTAL	mWh	37,225,084	39,732,780	40,030,421	40,923,065	6.3%	0.7%	2.2%
UNITS OF FUEL BURNED								
LIGHT OIL	BBL	198,094	121,326	88,104	98,831	-63.3%	-37.7%	12.2%
COAL	TON	3,745,945	1,976,271	1,459,784	2,964,417	-89.5%	-35.4%	103.1%
GAS	MCF	222,082,583	262,546,275	264,606,132	234,613,566	15.4%	0.8%	-11.3%
OTHER		0	0	0	0	0.0%	0.0%	0.0%
BTUS BURNED (MMBTU)								
LIGHT OIL		1,141,753	698,679	465,281	575,748	-63.4%	-50.2%	23.7%
COAL		86,196,682	44,098,849	34,576,012	68,909,648	-95.5%	-27.5%	99.3%
GAS		226,705,787	268,325,594	267,832,635	234,613,566	15.5%	-0.2%	-12.4%
OTHER		0	0	0	0	0.0%	0.0%	0.0%
TOTAL	MMBTU	314,044,222	313,123,122	302,873,928	304,098,962	-0.3%	-3.4%	0.4%
GENERATION MIX (% mWh)								
LIGHT OIL		0.24%	0.13%	0.07%	0.11%	-75.8%	-142.9%	0.0%
COAL		22.62%	10.82%	8.21%	16.24%	-109.0%	-31.7%	97.4%
GAS		77.06%	88.51%	89.82%	80.55%	12.9%	1.4%	-10.4%
SOLAR		0.07%	0.54%	1.90%	3.11%	92.6%	73.7%	63.2%
OTHER		0.00%	0.00%	0.00%	0.00%	0.0%	0.0%	0.0%
TOTAL	%	100.00%	100.00%	100.00%	100.00%	0.0%	0.0%	0.0%
FUEL COST PER UNIT								
LIGHT OIL	$/BBL	114.14	117.26	117.36	110.21	2.7%	0.1%	-6.1%
COAL	$/TON	73.73	81.78	87.55	63.97	9.8%	6.6%	-26.9%
GAS	$/MCF	4.61	4.02	3.35	4.24	-14.7%	-19.9%	26.5%
OTHER		0.00	0.00	0.00	0.00	0.0%	0.0%	0.0%
FUEL COST PER MMBTU ($/MMBTU)								
LIGHT OIL		19.80	20.36	22.22	18.92	2.8%	8.4%	-14.9%
COAL		3.20	3.67	3.70	2.75	12.6%	0.8%	-25.5%
GAS		4.52	3.93	3.31	4.24	-14.8%	-18.8%	28.0%
OTHER		0.00	0.00	0.00	0.00	0.0%	0.0%	0.0%
TOTAL	$/MMBTU	4.21	3.93	3.38	3.93	-7.1%	-16.2%	16.1%
BTU BURNED PER kWh (BTU/kWh)								
LIGHT OIL		12,625	13,305	16,712	12,577	5.1%	20.4%	-24.7%
COAL		10,235	10,255	10,521	10,372	0.2%	2.5%	-1.4%
GAS		7,903	7,630	7,449	7,118	-3.6%	-2.4%	-4.4%
OTHER		0	0	0	0	0.0%	0.0%	0.0%
TOTAL	BTU/kWh	8,436	7,881	7,566	7,431	-7.1%	-4.2%	-1.8%
GENERATED FUEL COST PER kWh (C/kWh)								
LIGHT OIL		25.00	27.09	37.14	23.79	7.7%	27.1%	-35.9%
COAL		3.28	3.76	3.89	2.85	12.7%	3.4%	-26.6%
GAS		3.57	3.00	2.47	3.02	-18.9%	-21.7%	22.3%
OTHER		0.00	0.00	0.00	0.00	0.0%	0.0%	0.0%
TOTAL	C/kWh	3.55	3.10	2.56	2.92	-14.7%	-21.0%	14.1%

Duke Energy Florida, LLC
Fuel and Purchased Power Cost Recovery Clause
Capital Structure and Cost Rates Applied to Capital Projects
Estimated for the Period of : January 2021 through December 2021

	Adjusted Retail $000's	Ratio	Cost Rate	Weighted Cost	PreTax Weighted Cost Rate
Common Equity	$ 6,641,460	43.82%	10.50%	4.60%	6.10%
Long Term Debt	5,949,953	39.26%	4.37%	1.72%	1.72%
Short Term Debt	(71,620)	-0.47%	1.80%	-0.01%	-0.01%
Customer Deposits - Active	189,295	1.25%	2.37%	0.03%	0.03%
Customer Deposits - Inactive	1,593	0.01%	0.00%	0.00%	0.00%
Deferred Tax	2,265,754	14.95%	0.00%	0.00%	0.00%
Deferred Tax (FAS 109)	-	0.00%	0.00%	0.00%	0.00%
ITC	180,082	1.19%	7.60%	0.09%	0.09%
	15,156,516	100.00%		6.43%	7.92%
			Total Debt	1.83%	1.83%
			Total Equity	4.60%	6.10%

Note> 2021 WACC complies with the Amended Unopposed Joint Motion to Modify Order No. PSC-2012-0425-PAA-UE Regarding Weighted Average Cost of Capital Methodology approved May 20, 2020 in Docket No, 20200118-EU, Order No. PSC-2020-0165-PAA-EU.

DUKE ENERGY FLORIDA, LLC

Fuel and Capacity Cost Recovery Factor

January through December 2021

PART 3 – 2021 CAPACITY COST RECOVERY SCHEDULES

Schedule E12-A – Calculation of Projected Capacity Costs

Schedule E12-B – Calculation of Actual/Estimated True-up

Schedule E12-D – Calculation of Energy and Demand Percent by Rate Class

Schedule E12-E – Calculation of Capacity Cost Recovery Factors by Rate Class

		EST	EST	EST	EST	EST	EST	EST	EST	EST	EST	EST	EST	
		Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Nov-21	Dec-21	TOTAL
1	**Base Production Level Capacity Costs**													
2	Orange Cogen (ORANGECO)	6,188,877	6,188,877	6,188,877	6,188,877	6,188,877	6,188,877	6,188,877	6,188,877	6,188,877	6,188,877	6,188,877	6,188,877	74,266,522
3	Orlando Cogen Limited (ORLACOGL)	6,225,933	6,225,933	6,225,933	6,225,933	6,225,933	6,225,933	6,225,933	6,225,933	6,225,933	6,225,933	6,225,933	6,225,933	74,711,196
4	Pasco County Resource Recovery (PASCOUNT)	2,284,360	2,284,360	2,284,360	2,284,360	2,284,360	2,284,360	2,284,360	2,284,360	2,284,360	2,284,360	2,284,360	2,284,360	27,412,320
5	Pinellas County Resource Recovery (PINCOUNT)	5,437,770	5,437,770	5,437,770	5,437,770	5,437,770	5,437,770	5,437,770	5,437,770	5,437,770	5,437,770	5,437,770	5,437,770	65,253,240
6	Polk Power Partners, L.P. (MULBERRY/ROYSTER)	8,498,223	8,498,223	8,498,223	8,498,223	8,498,223	8,498,223	8,498,223	8,498,223	8,498,223	8,498,223	8,498,223	8,498,223	101,978,670
7	Subtotal - Base Level Capacity Costs	28,635,162	28,635,162	28,635,162	28,635,162	28,635,162	28,635,162	28,635,162	28,635,162	28,635,162	28,635,162	28,635,162	28,635,162	343,621,948
8	Base Production Jurisdictional Responsibility	92.885%	92.885%	92.885%	92.885%	92.885%	92.885%	92.885%	92.885%	92.885%	92.885%	92.885%	92.885%	
9	Base Level Jurisdictional Capacity Costs	26,597,771	26,597,770	26,597,770	26,597,770	26,597,770	26,597,771	26,597,771	26,597,771	26,597,771	26,597,771	26,597,771	26,597,771	319,173,244
10	**Intermediate Production Level Capacity Costs**													
11	Southern Franklin	4,950,486	4,950,486	2,951,482	2,951,482	3,237,054	-	-	-	-	-	-	-	19,040,989
12	Schedule H Capacity Sales	-	-	-	-	-	-	-	-	-	-	-	-	-
13	Subtotal - Intermediate Level Capacity Costs	4,950,486	4,950,486	2,951,482	2,951,482	3,237,054	-	-	-	-	-	-	-	19,040,989
14	Intermediate Production Jurisdict. Responsibility	72.703%	72.703%	72.703%	72.703%	72.703%	72.703%	72.703%	72.703%	72.703%	72.703%	72.703%	72.703%	
15	Intermediate Level Jurisdict. Capacity Costs	3,599,152	3,599,152	2,145,816	2,145,816	2,353,436	-	-	-	-	-	-	-	13,843,372
16	**Peaking Production Level Capacity Costs**													
17	Shady Hills	1,971,891	1,971,891	1,408,494	1,366,449	1,913,029	3,889,124	3,889,124	3,889,124	1,814,925	1,366,449	1,366,449	1,971,891	26,818,842
18	Vandolah (NSG)	2,811,161	2,826,948	2,025,934	2,003,380	2,732,224	5,634,444	5,617,529	5,572,423	2,666,444	1,963,912	2,009,019	2,826,948	38,690,366
19	Other	-	-	-	-	-	-	-	-	-	-	-	-	-
20	Subtotal - Peaking Level Capacity Costs	4,783,052	4,798,839	3,434,427	3,369,830	4,645,253	9,523,569	9,506,654	9,461,547	4,481,369	3,330,362	3,375,468	4,798,839	65,509,208
21	Peaking Production Jurisdictional Responsibility	95.924%	95.924%	95.924%	95.924%	95.924%	95.924%	95.924%	95.924%	95.924%	95.924%	95.924%	95.924%	
22	Peaking Level Jurisdictional Capacity Costs	4,588,095	4,603,238	3,294,440	3,232,475	4,455,913	9,135,388	9,119,162	9,075,895	4,298,708	3,194,616	3,237,884	4,603,238	62,839,052
23	**Other Capacity Costs**													
24	Retail Wheeling	(77,693)	(43,096)	(23,969)	(10,778)	(29,249)	(35,507)	(47,172)	(42,531)	(40,483)	(18,724)	(22,824)	(22,452)	(414,476)
25	Ridge Generating Station L.P. Termination [1]	666,245	662,777	659,309	655,842	652,374	648,906	645,438	641,971	638,503	635,035	631,568	628,100	7,766,067
26	State Corporate Income Tax Change [2]	(232,776)	(232,776)	(232,776)	(232,776)	(232,776)	(232,776)	(232,776)	(232,776)	(232,776)	(232,776)	(232,776)	(232,776)	(2,793,306)
27	CR1&2 NBV [3]	6,716,036	6,716,036	6,716,036	6,716,036	6,716,036	6,716,036	6,716,036	6,716,036	6,716,036	6,716,036	6,716,036	6,716,036	80,592,431
28	SoBRA True-Up - Columbia [4]	(133,589)	-	-	-	-	-	-	-	-	-	-	-	(133,589)
29	SoBRA True-Up - DeBary [4]	(77,810)	-	-	-	-	-	-	-	-	-	-	-	(77,810)
30	SoBRA True-Up - Lake Placid [4]	(213,688)	-	-	-	-	-	-	-	-	-	-	-	(213,688)
31	SoBRA True-Up - Trenton [4]	(597,927)	-	-	-	-	-	-	-	-	-	-	-	(597,927)
32	Total Other Capacity Costs	6,048,797	7,102,942	7,118,601	7,128,324	7,106,385	7,096,660	7,081,527	7,082,701	7,081,280	7,099,572	7,092,004	7,088,909	84,127,702
33	**Total Capacity Costs (line 9+15+22+32)**	40,833,814	41,903,102	39,156,627	39,104,385	40,513,504	42,829,818	42,798,460	42,756,366	37,977,759	36,891,958	36,927,658	38,289,918	479,983,370
34	Actual/Estimated True-Up Provision - Jan - Dec 2020													463,084
35	**Total Capacity Costs w/ True-Up**													480,446,455
36	Revenue Tax Multiplier													1.00072
37	**Total Recoverable Capacity Costs**													480,792,376
38	**ISFSI Revenue Requirement [3]**													6,879,837
39	Revenue Tax Multiplier													1.00072
40	**Total Recoverable ISFSI Costs**													6,884,791
41	**Total Recoverable Capacity & ISFSI Costs (line 33+40)**													487,677,167

[1] Approved in Commission Order No. PSC-2018-0532-PAA-EQ.

[2] See Unopposed Motion for Approval of a Third Implementation Stipulation filed in Docket No. 20200001.

[3] As set forth in DEF's 2017 Settlement, approved in Commission Order No. PSC-2017-0451-AS-EU.

[4] True-up of solar project costs as filed in Docket No. 20190072 and 20180149 (Columbia) in accordance with paragraph 15g of the 2017 Settlement.

Contract Data:

	Name	Start Date	Expiration Date	Type	Purchase/Sale	MW
1	Orlando Cogen Limited (ORLACOGL)	Sep-93	Dec-23	QF	Purch	115.00
2	Orange Cogen (ORANGECO)	Jul-95	Dec-25	QF	Purch	104.00
3	Pasco County Resource Recovery (PASCOUNT)	Jan-95	Dec-24	QF	Purch	23.00
4	Pinellas County Resource Recovery (PINCOUNT)	Jan-95	Dec-24	QF	Purch	54.75
5	Polk Power Partners, L. P. (MULBERY/ROYSTER)	Aug-94	Aug-24	QF	Purch	115.00
6	Southern - Franklin	Jun-16	May-21	Other	Purch	424.00
7	Schedule H Capacity - New Smyrna Beach	Nov-85	see note (1)	Other	Sale	1.00
8	Vandolah (NSG)	Jun-12	May-27	Other	Purch	655.00
9	Shady Hills Tolling Agreement	Apr-07	Apr-24	Other	Purch	515.00

(1) The New Smyrna Beach (NSB) Schedule H contract is in effect until cancelled by either Duke Energy Florida or NSB upon 1 year's written notice.

Duke Energy Florida, LLC
Calculation of Projected Capacity Costs
For the Year 2020

Docket No. 20200001-EI
Exhibit__CAM-3, Part 3
Schedule E12-B
Page 1 of 1

		ACT Jan-20	ACT Feb-20	ACT Mar-20	ACT Apr-20	ACT May-20	ACT Jun-20	EST Jul-20	EST Aug-20	EST Sep-20	EST Oct-20	EST Nov-20	EST Dec-20	TOTAL
1	**Base Production Level Capacity Costs**													
2	Orange Cogen (ORANGECO)	5,880,980	5,893,358	5,887,169	5,887,169	5,887,169	5,887,169	5,887,169	5,887,169	5,887,169	5,887,169	5,887,169	5,887,169	70,646,031
3	Orlando Cogen Limited (ORLACOGL)	5,923,355	5,923,355	5,923,355	5,923,355	5,923,355	5,923,355	5,923,355	5,923,355	5,923,355	5,923,355	5,923,355	5,923,355	71,080,258
4	Pasco County Resource Recovery (PASCOUNT)	2,147,740	2,147,740	2,147,740	2,147,740	2,147,740	2,147,740	2,147,740	2,147,740	2,147,740	2,147,740	2,147,740	2,147,740	25,772,880
5	Pinellas County Resource Recovery (PINCOUNT)	5,112,555	5,112,555	5,112,555	5,112,555	5,112,555	5,112,555	5,112,555	5,112,555	5,112,555	5,112,555	5,112,555	5,112,555	61,350,660
6	Polk Power Partners, L.P. (MULBERRY/ROYSTER)	8,086,717	8,086,717	8,086,717	8,086,717	8,086,717	8,086,717	8,086,717	8,086,717	8,086,717	8,086,717	8,086,717	8,086,717	97,040,600
7	Subtotal - Base Level Capacity Costs	27,151,347	27,163,725	27,157,536	27,157,536	27,157,536	27,157,536	27,157,535	27,157,535	27,157,535	27,157,535	27,157,535	27,157,535	325,890,428
8	Base Production Jurisdictional Responsibility	92.885%	92.885%	92.885%	92.885%	92.885%	92.885%	92.885%	92.885%	92.885%	92.885%	92.885%	92.885%	
9	Base Level Jurisdictional Capacity Costs	25,219,529	25,231,025	25,225,276	25,225,276	25,225,276	25,225,277	25,225,277	25,225,277	25,225,277	25,225,277	25,225,277	25,225,277	302,703,319
10	**Intermediate Production Level Capacity Costs**													
11	Southern Franklin	4,016,449	5,550,785	2,815,069	2,816,679	1,738,090	4,096,953	6,653,118	6,653,118	4,939,686	2,940,682	2,940,682	3,797,398	48,958,709
12	Schedule H Capacity Sales	-	-	(32,469)	-	-	-	-	-	-	-	-	-	(32,469)
13	Subtotal - Intermediate Level Capacity Costs	4,016,449	5,550,785	2,782,600	2,816,679	1,738,090	4,096,953	6,653,118	6,653,118	4,939,686	2,940,682	2,940,682	3,797,398	48,926,240
14	Intermediate Production Jurisdict. Responsibility	72.703%	72.703%	72.703%	72.703%	72.703%	72.703%	72.703%	72.703%	72.703%	72.703%	72.703%	72.703%	
15	Intermediate Level Jurisdict. Capacity Costs	2,920,079	4,035,587	2,023,034	2,047,810	1,263,645	2,978,608	4,837,016	4,837,016	3,591,300	2,137,964	2,137,964	2,760,822	35,570,845
16	**Peaking Production Level Capacity Costs**													
17	Shady Hills	1,973,160	1,973,160	1,973,160	802,440	1,912,680	3,911,760	3,889,124	3,889,124	1,814,925	1,366,449	1,366,449	1,971,891	26,844,323
18	Vandolah (NSG)	2,939,299	2,876,217	1,958,481	1,943,807	2,807,348	5,839,892	5,617,529	5,572,423	2,666,444	1,963,912	2,009,019	2,826,948	39,021,320
19	Other	-	-	-	-	-	-	-	-	-	-	-	-	-
20	Subtotal - Peaking Level Capacity Costs	4,912,459	4,849,377	3,931,641	2,746,247	4,720,028	9,751,652	9,506,654	9,461,547	4,481,369	3,330,362	3,375,468	4,798,839	65,865,643
21	Peaking Production Jurisdictional Responsibility	95.924%	95.924%	95.924%	95.924%	95.924%	95.924%	95.924%	95.924%	95.924%	95.924%	95.924%	95.924%	
22	Peaking Level Jurisdictional Capacity Costs	4,712,227	4,651,717	3,771,387	2,634,310	4,527,640	9,354,175	9,119,162	9,075,895	4,298,708	3,194,616	3,237,884	4,603,238	63,180,959
23	**Other Capacity Costs**													
24	Retail Wheeling	(10,726)	(9,947)	-	(17,012)	(2,126)	(837)	(40,983)	(45,545)	(38,603)	(15,942)	(15,280)	(41,558)	(238,559)
25	Ridge Generating Station L.P. Termination [1]	708,094	704,621	701,149	697,676	694,203	690,731	687,051	683,583	680,115	676,648	673,180	669,712	8,266,764
26	State Corporate Income Tax Change [2]	-	-	(3,491,633)	(232,776)	(232,776)	(232,776)	(232,776)	(232,776)	(232,776)	(232,776)	(232,776)	(232,776)	(5,586,612)
27	Total Other Capacity Costs	697,369	694,674	(2,790,484)	447,888	459,301	457,118	413,292	405,262	408,737	427,930	425,124	395,379	2,441,593
28	**Total Capacity Costs (line 9+15+22+27)**	33,549,204	34,613,003	28,229,213	30,355,284	31,475,861	38,015,179	39,594,748	39,543,450	33,524,022	30,985,786	31,026,249	32,984,716	403,896,715
29	**ISFSI Revenue Requirement** [3]	573,320	573,320	573,320	573,320	573,320	573,320	573,320	573,320	573,320	573,320	573,320	573,320	6,879,837
30	**Total Recoverable Capacity & ISFSI Costs (line 28+29)**	34,122,523	35,186,323	28,802,534	30,928,605	32,049,181	38,588,498	40,168,068	40,116,770	34,097,342	31,559,106	31,599,569	33,558,036	410,776,553
31	**Capacity Revenues**													
32	Capacity Cost Recovery Revenues (net of tax)	27,694,435	28,661,108	29,875,620	34,161,020	32,020,716	36,912,727	41,235,583	41,983,900	40,977,417	37,057,076	29,549,322	29,176,204	409,305,128
33	Prior Period True-Up Provision Over/(Under) Recovery	154,042	154,042	154,042	154,042	154,042	154,042	154,042	154,042	154,042	154,042	154,042	154,042	1,848,509
34	**Current Period Revenues (net of tax)**	27,848,477	28,815,151	30,029,662	34,315,063	32,174,759	37,066,769	41,389,626	42,137,943	41,131,459	37,211,119	29,703,365	29,330,246	411,153,637
35	**True-Up Provision**													
36	True-Up Provision - Over/(Under) Recov (Line 34-30)	(6,274,046)	(6,371,172)	1,227,128	3,386,458	125,578	(1,521,729)	1,221,558	2,021,173	7,034,117	5,652,012	(1,896,204)	(4,227,790)	377,083
37	Interest Provision for the Month	(2,912)	(11,495)	(17,867)	(8,783)	(459)	(680)	(331)	(256)	19	239	157	(19)	(42,389)
38	Current Cycle Balance - Over/(Under)	(6,276,958)	(12,659,626)	(11,450,367)	(8,072,693)	(7,947,575)	(9,469,984)	(8,248,757)	(6,227,840)	806,295	6,458,546	4,562,499	334,694	334,694
39	Prior Period Balance - Over/(Under) Recovered	1,050,730	1,050,730	1,050,730	1,050,730	1,050,730	1,050,730	1,050,730	1,050,730	1,050,730	1,050,730	1,050,730	1,050,730	1,050,730
40	Prior Period Cumulative True-Up Collected/(Refunded)	(154,042)	(308,085)	(462,127)	(616,170)	(770,212)	(924,255)	(1,078,297)	(1,232,339)	(1,386,382)	(1,540,424)	(1,694,467)	(1,848,509)	(1,848,509)
41	Prior Period True-up Balance - Over/(Under)	896,686	742,643	588,601	434,559	280,516	126,474	(27,567)	(181,609)	(335,651)	(489,694)	(643,736)	(797,779)	(797,779)
42	**Net Capacity True-up Over/(Under) (Line 38+41)**	($5,380,272)	($11,916,982)	($10,861,764)	($7,638,133)	($7,667,056)	($9,343,508)	($8,276,324)	($6,409,449)	$470,644	$5,968,852	$3,918,763	($463,084)	($463,084)

[1] Approved in Commission Order No. PSC-2018-0532-PAA-EQ.

[2] See Third Implementation Stipulation attached as Appendix A to the Petition for the 2020 Actual/Estimated TU in Docket 20200001.

[3] Approved in Commission Order No. PSC-2016-0425-PAA-EI.

Duke Energy Florida, LLC
Calculation of Energy and Demand Percent by Rate Class
Using 12 CP & 1/13th AD Allocation Method for Production Demand
For the Year 2021

Docket No. 20200001-EI
Exhibit__CAM-3, Part 3
Schedule E12-D

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
Rate Class	Average 12CP Load Factor at Meter (%)	Sales at Meter (MWh)	Avg 12 CP at Meter (MW)	Delivery Efficiency Factor	Sales at Source (Generation) (MWh)	Avg 12 CP at Source (MW)	Annual Average Demand (MWh)	Annual Average Demand Allocator (%)	12CP Allocator (%)	12CP 1/13 AD Demand Allocator (%)	Base Energy & Demand Revenues ($000s)	ISFSI Uniform Percent Allocation ($000s)
Residential												**0.31%**
RS-1, RST-1, RSL-1, RSL-2, RSS-1												
Secondary	0.548	21,141,521	4,405.75	0.9307248	22,715,115	4,733.68	2,593.05	53.677%	61.440%	60.843%	1,428,419	4,418
General Service Non-Demand												
GS-1, GST-1												
Secondary	0.576	2,057,599	408.02	0.9307248	2,210,749	438.39	252.37	5.224%	5.690%	5.654%		
Primary	0.576	14,043	2.78	0.9736607	14,423	2.86	1.65	0.034%	0.037%	0.037%		
Transmission	0.576	2,593	0.51	0.9836607	2,636	0.52	0.30	0.006%	0.007%	0.007%		
								5.264%	5.734%	5.698%	143,143	443
General Service												
GS-2 Secondary	1.000	194,563	22.21	0.9307248	209,044	23.86	23.86	0.494%	0.310%	0.324%	5,240	16
General Service Demand												
GSD-1, GSDT-1												
Secondary	0.742	10,950,999	1,683.92	0.9307248	11,766,098	1,809.26	1,343.16	27.804%	23.483%	23.815%		
Transm Del/ Primary Mtr	0.742	0	0.00	0.9736607	0	0.00	0.00	0.000%	0.000%	0.000%		
Sec Del/Primary Mtr	0.742	28,262	4.35	0.9736607	29,027	4.46	3.31	0.069%	0.058%	0.059%		
Primary	0.742	2,001,891	307.83	0.9736607	2,056,046	316.16	234.71	4.859%	4.104%	4.162%		
Transmission	0.742	103,104	15.85	0.9836607	104,817	16.12	11.97	0.248%	0.209%	0.212%		
SS-1 Primary	0.796	36,645	5.26	0.9736607	37,636	5.40	4.30	0.089%	0.070%	0.072%		
Transm Del/ Primary Mtr	0.796	1,821	0.26	0.9736607	1,870	0.27	0.21	0.004%	0.003%	0.004%		
Transmission	0.796	5,412	0.78	0.9836607	5,502	0.79	0.63	0.013%	0.010%	0.010%		
								33.085%	27.938%	28.334%	564,272	1,745
Curtailable												
CS-1, CST-1, CS-2, CST-2, SS-3												
Primary	1.082	61,840	6.52	0.9736607	63,513	6.70	7.25	0.150%	0.087%	0.092%		
SS-3 Primary	1.248	68,295	6.25	0.9736607	70,142	6.42	8.01	0.166%	0.083%	0.090%		
								0.316%	0.170%	0.181%	5,729	18
Interruptible												
IS-1, IST-1, IS-2, IST-2												
Secondary	0.911	445,099	55.76	0.9307248	478,228	59.91	54.59	1.130%	0.778%	0.805%		
Sec Del/Primary Mtr	0.911	5,866	0.73	0.9736607	6,025	0.75	0.69	0.014%	0.010%	0.010%		
Primary Del / Primary Mtr	0.911	1,226,102	153.60	0.9736607	1,259,270	157.75	143.75	2.976%	2.048%	2.119%		
Primary Del / Transm Mtr	0.911	301	0.04	0.9836607	306	0.04	0.03	0.001%	0.000%	0.001%		
Transm Del/ Primary Mtr	0.911	369,971	46.35	0.9736607	379,979	47.60	43.38	0.898%	0.618%	0.639%		
Transm Del/ Transm Mtr	0.911	459,412	57.55	0.9836607	467,043	58.51	53.32	1.104%	0.759%	0.786%		
SS-2 Primary	0.686	14,726	2.45	0.9736607	15,124	2.52	1.73	0.036%	0.033%	0.033%		
Transm Del/ Primary Mtr	0.686	45,318	7.54	0.9736607	46,544	7.75	5.31	0.110%	0.101%	0.101%		
Transmission	0.686	3,450	0.57	0.9836607	3,507	0.58	0.40	0.008%	0.008%	0.008%		
								6.276%	4.353%	4.501%	69,192	214
Lighting												
LS-1 (Secondary)	10.191	349,344	3.91	0.9307248	375,347	4.20	42.85	0.887%	0.055%	0.119%	9,970	31
Total		39,588,176	7,198.81		42,317,991	7,704.50	4,830.82	100.000%	100.000%	100.000%	2,225,967	6,885

Notes:

(1) Average 12CP load factor based on load research study filed July 31, 2018 (FPSC rule 25-6.0437 (7))
(2) Projected mWh sales for the period Jan-Dec 2021
(3) Calculated: Column 2 / (8,760 hours x Column 1)
(4) Based on system average line loss analysis for 2019
(5) Calculated: Column 2 / Column 4
(6) Calculated: Column 3 / Column 4
(7) Calculated: Column 5 / 8,760 hours
(8) Calculated: Column 7 / Total Column 7
(9) Calculated: Column 6 / Total Column 6
(10) Calculated: Column 8 x 1/13 + Column 9 x 12/13
(11) Projected Base Energy & Demand Revenues for Jan-Dec 2021
(12) Uniform Percent Calculated: Column 12 Total / Column 11 Total
Calculated: Column 11 x Uniform Percent

Duke Energy Florida, LLC
Calculation of Capacity Cost Recovery Factors by Rate Class
For the Year 2021

Docket No. 20200001-EI
Exhibit__CAM-3, Part 3
Schedule E12-E
Page 1 of 1

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
Rate Class	12CP 1/13 AD Demand Allocator (%)	Effective mWh at Secondary Level (MWh)	Capacity Production Demand Costs ($)	ISFSI Dry Cask Storage Costs ($)	Capacity + ISFSI Production Demand Costs ($)	Capacity CCR Factor (c/kWh)	ISFSI CCR Factor (c/kWh)	Capacity + ISFSI CCR Factor (c/kWh)	Billing KW Load Factor (%)	Projected Effective KW at Meter Level (kW)	Capacity CCR Factor ($/kW-mo)	ISFSI CCR Factor ($/kW-mo)	Capacity + ISFSI CCR Factor ($/kW-mo)
Residential													
RS-1, RST-1, RSL-1, RSL-2, RSS-1													
Secondary	60.843%	21,141,521	$292,529,807	$4,418,021	$296,947,828	**1.384**	**0.021**	**1.405**					
General Service Non-Demand													
GS-1, GST-1													
Secondary		2,057,599				**1.321**	**0.021**	**1.342**					
Primary		13,903				**1.308**	**0.021**	**1.329**					
Transmission		2,541				**1.295**	**0.021**	**1.315**					
TOTAL GS	5.698%	2,074,042	27,394,899	442,734	27,837,634								
General Service													
GS-2 Secondary	0.324%	194,563	1,557,324	16,208	1,573,532	**0.800**	**0.008**	**0.808**					
General Service Demand													
GSD-1, GSDT-1, SS-1													
Secondary		10,950,999									**4.15**	**0.05**	**4.20**
Primary		2,047,933									**4.11**	**0.05**	**4.16**
Transmission		106,346									**4.07**	**0.05**	**4.12**
TOTAL GSD	28.334%	13,105,277	136,225,441	1,745,262	137,970,703				54.71%	32,811,189			
Curtailable													
CS-1, CST-1, CS-2, CST-2, CS-3, CST-3, SS-3													
Secondary		-									**1.19**	**0.02**	**1.22**
Primary		128,834									**1.18**	**0.02**	**1.21**
Transmission		-									**1.17**	**0.02**	**1.20**
TOTAL CS	0.181%	128,834	872,348	17,719	890,067				24.10%	732,258			
Interruptible													
IS-1, IST-1, IS-2, IST-2, SS-2													
Secondary		445,099									**3.47**	**0.03**	**3.50**
Primary		1,645,363									**3.44**	**0.03**	**3.47**
Transmission		453,900									**3.40**	**0.03**	**3.43**
TOTAL IS	4.501%	2,544,362	21,642,327	214,008	21,856,336				55.84%	6,242,183			
Lighting													
LS-1 Secondary	0.119%	349,344	570,230	30,838	601,068	**0.163**	**0.009**	**0.172**					
Total	100.000%	39,537,943	$480,792,376	$6,884,791	$487,677,167	**1.216**	**0.017**	**1.233**					

Notes:
(1) From Schedule E12-D, Column 10
(2) Projected mWh sales at effective voltage level for Jan-Dec 2021
(3) Column 1 x Total Recoverable Capacity Costs (Schedule E12-A)
(4) From Schedule E12-D, Column 12
(5) Column 3 + Column 4
(6) (Column 3 / Column 2) / 10
(7) (Column 4 / Column 2) / 10
(8) Column 6 + Column 7
(9) Class Billing kW Load Factor
(10) Column 2 x 1000 / 8,760 / Column 9 x 12
(11) Column 3 / Column 10
(12) Column 4 / Column 10
(13) Column 5 / Column 10

***Calculation of Standby Service kW Charges:**			
	Capacity + Ridge + ISFSI Cost	Effective kW	$/kW
Total GSD, CS, IS	$160,717,105	39,785,630	4.04
SS-1, 2, 3 - $/kW-mo	Secondary	Primary	Trans
Monthly - $4.04/kW * 10%	0.404	0.400	0.396
Daily - $4.04/kW / 21	0.192	0.190	0.188

GPIF REWARD/PENALTY SCHEDULES

Description	Sheet
Index	1
Reward/Penalty Table (Actual)	2
Calculation of Maximum Incentive Dollars (Actual)	3
Calculation of System Actual GPIF Points	4
GPIF Unit Performance Summary	5
Actual Unit Performance Data	6
Adjustments to EAF Actual	7
Adjustments to ANOHR Actual	8
Generating Performance Incentive Points Table	9-15
Actual Unit Performance Data	16-22
Planned Outage Schedules (Actual)	23-24

Original Sheet No. 6.101.1

GENERATING PERFORMANCE INCENTIVE FACTOR

REWARD/PENALTY TABLE

ACTUAL

Duke Energy Florida
January 2019 - December 2019

	Generating Performance Incentive Points (GPIF)	Fuel Savings/Loss ($)	Generating Performance Incentive Factor ($)
	10	$ 35,646,676	$ 17,823,338
	9	$ 32,082,009	$ 16,041,004
	8	$ 28,517,341	$ 14,258,671
	7	$ 24,952,673	$ 12,476,337
	6	$ 21,388,006	$ 10,694,003
	5	$ 17,823,338	$ 8,911,669
	4	$ 14,258,671	$ 7,129,335
	3	$ 10,694,003	$ 5,347,001
****	2.473	$ 8,815,423	$ 4,407,712
	2	$ 7,129,335	$ 3,564,668
	1	$ 3,564,668	$ 1,782,334
	0	$ -	$ -
	-1	$ (3,883,621)	$ (1,782,334)
	-2	$ (7,767,241)	$ (3,564,668)
	-3	$ (11,650,862)	$ (5,347,001)
	-4	$ (15,534,483)	$ (7,129,335)
	-5	$ (19,418,103)	$ (8,911,669)
	-6	$ (23,301,724)	$ (10,694,003)
	-7	$ (27,185,345)	$ (12,476,337)
	-8	$ (31,068,965)	$ (14,258,671)
	-9	$ (34,952,586)	$ (16,041,004)
	-10	$ (38,836,207)	$ (17,823,338)

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GENERATION PERFORMANCE INCENTIVE FACTOR

CALCULATION OF MAXIMUM ALLOWED INCENTIVE DOLLARS

Duke Energy Florida
January 2019 - December 2019

1	Beginning of period balance of common equity	$ 6,098,448,855	
	END OF MONTH BALANCE OF COMMON EQUITY:		
2	Month of JANUARY 2019	$ 6,146,604,577	
3	Month of FEBRUARY 2019	$ 6,161,844,335	
4	Month of MARCH 2019	$ 6,200,654,141	
5	Month of APRIL 2019	$ 6,260,679,827	
6	Month of MAY 2019	$ 6,322,800,639	
7	Month of JUNE 2019	$ 6,399,801,391	
8	Month of JULY 2019	$ 6,479,842,500	
9	Month of AUGUST 2019	$ 6,581,911,481	
10	Month of SEPTEMBER 2019	$ 6,677,651,726	
11	Month of OCTOBER 2019	$ 6,724,733,894	
12	Month of NOVEMBER 2019	$ 6,773,097,968	
13	Month of DECEMBER 2019	$ 6,789,687,410	
14	Average common equity for the period	$ 6,432,135,288	
15	25 Basis Points	0.0025	
16	Revenue Expansion Factor	75.2739%	
17	Maximum allowed incentive dollars	$ 21,362,441	
18	Jurisdictional Sales *	39,187,343	MWH
19	Total Sales *	39,425,343	MWH
20	Jurisdictional Separation Factor	99.4000%	
21	Maximum allowed jurisdictional incentive dollars	$ 21,234,267	
22	Incentive Cap (50% of Projected Fuel Savings at 10 GPIF Point Level) From Sheet No. 6.101.1	$ 17,823,338	
23	Maximum Allowed GPIF Reward (Lesser of Line 21 and Line 22)	$ 17,823,338	

* Net sales (Sales - Interruptible)

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GENERATION PERFORMANCE INCENTIVE FACTOR

CALCULATION OF SYSTEM ACTUAL GPIF POINTS

Duke Energy Florida
January 2019 - December 2019

Plant/Unit	Performance Indicator EAF or ANOHR	Weighting Factor %	Unit Points	Weighted Unit Points
Bartow CC	EAF	1.92	10.000	0.192
	ANOHR	28.83	0.000	0.000
Crystal River 4	EAF	3.93	1.621	0.064
	ANOHR	18.92	6.135	1.160
Crystal River 5	EAF	2.08	-10.000	-0.208
	ANOHR	16.66	5.945	0.991
Hines 1	EAF	0.78	-10.000	-0.078
	ANOHR	7.71	-0.094	-0.007
Hines 2	EAF	0.23	10.000	0.023
	ANOHR	5.08	-1.093	-0.056
Hines 3	EAF	1.04	10.000	0.104
	ANOHR	5.02	0.000	0.000
Hines 4	EAF	2.88	10.000	0.288
	ANOHR	4.93	0.000	0.000
GPIF System		100.00		2.473

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GENERATION PERFORMANCE INCENTIVE FACTOR
GPIF UNIT PERFORMANCE SUMMARY

Duke Energy Florida
January 2019 - December 2019

Plant/Unit	Weighting Factor (%)	EAF Target (%)	EAF RANGE Max. (%)	EAF RANGE Min. (%)	Max. Fuel Savings ($000)	Max. Fuel Loss ($000)	EAF Adjusted Actual (%)	Estimated Fuel Savings/ Loss ($000)
Bartow CC	1.92	77.28	81.18	69.39	$684	($849)	83.68	$684
Crystal River 4	3.93	88.12	92.48	79.53	$1,399	($2,543)	88.82	$227
Crystal River 5	2.08	78.10	80.15	73.88	$741	($1,040)	67.45	($1,040)
Hines 1	0.78	91.96	92.78	90.26	$279	($253)	87.08	($253)
Hines 2	0.23	92.15	92.88	90.64	$82	($347)	93.49	$82
Hines 3	1.04	88.09	89.19	85.82	$370	($169)	89.59	$370
Hines 4	2.88	81.17	85.53	72.14	$1,026	($2,569)	87.03	$1,026
GPIF System	12.85				$4,580.5	($7,770.0)		$1,095.6

Plant/Unit	Weighting Factor (%)	ANOHR Target (BTU/KWH)	NOF	ANOHR RANGE Min. (Btu/kwh)	ANOHR RANGE Max. (Btu/kwh)	Max. Fuel Savings ($000)	Max. Fuel Loss ($000)	ANOHR Adjusted Actual (Btu/kwh)	Estimated Fuel Savings/ Loss ($000)
Bartow CC	28.83	8,075	65.8	7,426	8,724	$10,278	($10,278)	8,099	$0
Crystal River 4	18.92	10,237	74.9	9,700	10,773	$6,743	($6,743)	9,879	$4,137
Crystal River 5	16.66	10,206	71.0	9,648	10,764	$5,939	($5,939)	9,844	$3,531
Hines 1	7.71	7,337	82.6	6,921	7,754	$2,750	($2,750)	7,415	($26)
Hines 2	5.08	7,501	75.5	7,226	7,777	$1,811	($1,811)	7,598	($198)
Hines 3	5.02	7,354	76.1	7,110	7,599	$1,789	($1,789)	7,359	$0
Hines 4	4.93	7,050	85.3	6,838	7,262	$1,756	($1,756)	7,008	$0
GPIF System	87.15					$31,066.2	($31,066.2)		$7,443.8

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GENERATION PERFORMANCE INCENTIVE FACTOR
ACTUAL UNIT PERFORMANCE DATA

Duke Energy Florida
January 2019 - December 2019

Plant/Unit	ACTUAL EAF %	ADJUSTMENTS (1) TO EAF %	ADJUSTED ACTUAL EAF %
Bartow CC	81.69	1.99	83.68
Crystal River 4	85.75	3.08	88.82
Crystal River 5	59.14	8.31	67.45
Hines 1	87.05	0.03	87.08
Hines 2	95.95	-2.46	93.49
Hines 3	92.78	-3.18	89.59
Hines 4	87.18	-0.14	87.03

Plant/Unit	ACTUAL ANOHR BTU/KWH	ADJUSTMENTS (2) TO ANOHR BTU/KWH	ADJUSTED ACTUAL ANOHR BTU/KWH
Bartow CC	7,697.7	401.8	8,099.4
Crystal River 4	10,319.3	-440.8	9,878.6
Crystal River 5	10,167.2	-323.3	9,843.9
Hines 1	7,413.8	1.6	7,415.4
Hines 2	7,431.7	166.3	7,598.0
Hines 3	7,204.9	154.2	7,359.1
Hines 4	6,997.5	10.5	7,008.0

(1) For documentation of adjustments to actual EAF, see sheet 7 of 24.
(2) For documentation of adjustments to actual ANOHR, see sheet 8 of 24.

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GENERATION PERFORMANCE INCENTIVE FACTOR
ADJUSTMENTS TO EAF ACTUAL

Duke Energy Florida
January 2019 - December 2019

EAF adjustments for Planned Outage Hours			Bartow CC BA4	Crystal River 4 CR4	Crystal River 5 CR5	Hines 1 HN1	Hines 2 HN2	Hines 3 HN3	Hines 4 HN4
1	Actual POH	Hrs.	1,438.53	511.98	2,426.43	554.96	335.81	558.49	826.89
2	Target POH	Hrs.	1,260.00	216.00	1,536.00	552.00	552.00	840.00	840.00
3	Adj. Factor (PH-POHT/PH-POHA)		1.02	1.04	1.14	1.00	0.97	0.97	1.00
4	Actual EUOH	Hrs.	165.84	736.63	1,153.22	579.85	19.17	74.12	296.44
5	Adj. EUOH (3*4)	Hrs.	169.89	763.07	1,315.35	580.06	18.68	71.58	295.95
6	Actual EAF	%	81.69	85.75	59.14	87.05	95.95	92.78	87.18
7	Adjusted EAF (using 2 & 5)	%	83.68	88.82	67.45	87.08	93.49	89.59	87.03
8	Difference (7-6)	%	1.99	3.08	8.31	0.03	-2.46	-3.18	-0.14
9	Total adj. to EAF	%	1.99	3.08	8.31	0.03	-2.46	-3.18	-0.14

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GENERATION PERFORMANCE INCENTIVE FACTOR
ADJUSTMENTS TO ANOHR ACTUAL

Duke Energy Florida
January 2019 - December 2019

ANOHR adjustments for Target NOF			Bartow CC BA4	Crystal River 4 CR4	Crystal River 5 CR5	Hines 1 HN1	Hines 2 HN2	Hines 3 HN3	Hines 4 HN4
1	Target NOF	%	65.8	74.9	71.0	82.6	75.5	76.1	85.3
2	Target ANOHR	Btu/kwh	8075.1	10236.6	10205.9	7337.2	7501.1	7354.3	7050.3
3	Actual NOF	%	81.3	60.9	58.0	82.9	85.8	84.0	86.6
4	Calc. ANOHR (using 3)	Btu/kwh	7,673.3	10,677.3	10,529.2	7,335.6	7,334.8	7,200.1	7,039.8
5	Total adj. to ANOHR (2-4)	Btu/kwh	401.8	-440.8	-323.3	1.6	166.3	154.2	10.5

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GENERATING PERFORMANCE INCENTIVE POINTS TABLE

Duke Energy Florida
January 2019 - December 2019

Unit: Bartow CC

	Equivalent Availability (Points)	Fuel Savings/Loss ($)	Equivalent Availability (%)	Average Heat Rate (Points)	Fuel Savings/Loss ($)	Average Heat Rate (BTU/KWH)	
****	10	$684,246	81.18	10	$10,277,850	7,425.7	
	10	$684,246	81.18	9	$9,250,065	7,483.1	
	9	$615,821	80.79	8	$8,222,280	7,540.5	
	8	$547,397	80.40	7	$7,194,495	7,598.0	
	7	$478,972	80.01	6	$6,166,710	7,655.4	
	6	$410,548	79.62	5	$5,138,925	7,712.9	
	5	$342,123	79.23	4	$4,111,140	7,770.3	
	4	$273,698	78.84	3	$3,083,355	7,827.7	
	3	$205,274	78.45	2	$2,055,570	7,885.2	
	2	$136,849	78.06	1	$1,027,785	7,942.6	
	1	$68,425	77.67	0	$0	8,000.1	
		$0	77.28	0.000	$0	8,099.4	****
	0	$0	77.28	0	$0	8,075.1	
		$0	77.28	0	$0	8,150.1	
	-1	($84,906)	76.49	-1	($1,027,785)	8,207.5	
	-2	($169,813)	75.70	-2	($2,055,570)	8,265.0	
	-3	($254,719)	74.92	-3	($3,083,355)	8,322.4	
	-4	($339,626)	74.13	-4	($4,111,140)	8,379.8	
	-5	($424,532)	73.34	-5	($5,138,925)	8,437.3	
	-6	($509,439)	72.55	-6	($6,166,710)	8,494.7	
	-7	($594,345)	71.76	-7	($7,194,495)	8,552.2	
	-8	($679,252)	70.97	-8	($8,222,280)	8,609.6	
	-9	($764,158)	70.18	-9	($9,250,065)	8,667.0	
	-10	($849,065)	69.39	-10	($10,277,850)	8,724.5	

Equivalent Availability Weighting Factor:	Heat Rate Weighting Factor:
1.92%	28.83%

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GENERATING PERFORMANCE INCENTIVE POINTS TABLE

Duke Energy Florida
January 2019 - December 2019

Unit: Crystal River 4

	Equivalent Availability (Points)	Fuel Savings/Loss ($)	Equivalent Availability (%)	Average Heat Rate (Points)	Fuel Savings/Loss ($)	Average Heat Rate (BTU/KWH)	
	10	$1,399,411	92.48	10	$6,742,841	9,700.3	
	9	$1,259,470	92.04	9	$6,068,557	9,746.5	
	8	$1,119,529	91.61	8	$5,394,273	9,792.6	
	7	$979,588	91.17	7	$4,719,989	9,838.7	
	6	$839,647	90.73	6.135	$4,136,733	9,878.6	****
	5	$699,706	90.30	6	$4,045,705	9,884.8	
	4	$559,764	89.86	5	$3,371,421	9,930.9	
	3	$419,823	89.43	4	$2,697,136	9,977.1	
	2	$279,882	88.99	3	$2,022,852	10,023.2	
****	1.621	$226,845	88.82	2	$1,348,568	10,069.3	
	1	$139,941	88.55	1	$674,284	10,115.4	
		$0	88.12	0	$0	10,161.6	
	0	$0	88.12	0	$0	10,236.6	
		$0	88.12	0	$0	10,311.6	
	-1	($254,256)	87.26	-1	($674,284)	10,357.7	
	-2	($508,511)	86.40	-2	($1,348,568)	10,403.8	
	-3	($762,767)	85.54	-3	($2,022,852)	10,449.9	
	-4	($1,017,022)	84.68	-4	($2,697,136)	10,496.0	
	-5	($1,271,278)	83.82	-5	($3,371,421)	10,542.2	
	-6	($1,525,534)	82.96	-6	($4,045,705)	10,588.3	
	-7	($1,779,789)	82.10	-7	($4,719,989)	10,634.4	
	-8	($2,034,045)	81.25	-8	($5,394,273)	10,680.5	
	-9	($2,288,300)	80.39	-9	($6,068,557)	10,726.7	
	-10	($2,542,556)	79.53	-10	($6,742,841)	10,772.8	

Equivalent Availability Weighting Factor:	Heat Rate Weighting Factor:
3.93%	18.92%

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GENERATING PERFORMANCE INCENTIVE POINTS TABLE

Duke Energy Florida
January 2019 - December 2019

Unit: Crystal River 5

	Equivalent Availability (Points)	Fuel Savings/Loss ($)	Equivalent Availability (%)	Average Heat Rate (Points)	Fuel Savings/Loss ($)	Average Heat Rate (BTU/KWH)	
	-------------	-----------------	-------------	-------------	---------------	-----------	
	10	$740,646	80.15	10	$5,939,197	9,648.1	
	9	$666,582	79.95	9	$5,345,278	9,696.3	
	8	$592,517	79.74	8	$4,751,358	9,744.6	
	7	$518,452	79.54	7	$4,157,438	9,792.9	
	6	$444,388	79.33	6	$3,563,518	9,841.2	
	5	$370,323	79.12	5.945	$3,530,853	9,843.9	****
	4	$296,259	78.92	5	$2,969,599	9,889.5	
	3	$222,194	78.71	4	$2,375,679	9,937.8	
	2	$148,129	78.51	3	$1,781,759	9,986.1	
	1	$74,065	78.30	2	$1,187,839	10,034.4	
		$0	78.10	1	$593,920	10,082.7	
	0	$0	78.10	0	$0	10,130.9	
		$0	78.10	0	$0	10,205.9	
	-1	($103,982)	77.68	0	$0	10,280.9	
	-2	($207,963)	77.25	-1	($593,920)	10,329.2	
	-3	($311,945)	76.83	-2	($1,187,839)	10,377.5	
	-4	($415,927)	76.41	-3	($1,781,759)	10,425.8	
	-5	($519,909)	75.99	-4	($2,375,679)	10,474.1	
	-6	($623,890)	75.57	-5	($2,969,599)	10,522.4	
	-7	($727,872)	75.15	-6	($3,563,518)	10,570.7	
	-8	($831,854)	74.73	-7	($4,157,438)	10,619.0	
	-9	($935,835)	74.31	-8	($4,751,358)	10,667.3	
	-10	($1,039,817)	73.88	-9	($5,345,278)	10,715.5	
****	-10	($1,039,817)	73.88	-10	($5,939,197)	10,763.8	

Equivalent Availability Weighting Factor:	Heat Rate Weighting Factor:
--------------------	--------------------
2.08%	16.66%

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GENERATING PERFORMANCE INCENTIVE POINTS TABLE

Duke Energy Florida
January 2019 - December 2019

Unit: Hines 1

	Equivalent Availability (Points)	Fuel Savings/Loss ($)	Equivalent Availability (%)	Average Heat Rate (Points)	Fuel Savings/Loss ($)	Average Heat Rate (BTU/KWH)	
	10	$278,783	92.78	10	$2,750,000	6,920.6	
	9	$250,905	92.70	9	$2,475,000	6,954.8	
	8	$223,027	92.62	8	$2,200,000	6,988.9	
	7	$195,148	92.54	7	$1,925,000	7,023.1	
	6	$167,270	92.46	6	$1,650,000	7,057.3	
	5	$139,392	92.37	5	$1,375,000	7,091.4	
	4	$111,513	92.29	4	$1,100,000	7,125.6	
	3	$83,635	92.21	3	$825,000	7,159.7	
	2	$55,757	92.13	2	$550,000	7,193.9	
	1	$27,878	92.05	1	$275,000	7,228.1	
		$0	91.96	0	$0	7,262.2	
	0	$0	91.96	0	$0	7,337.2	
		$0	91.96	0	$0	7,412.2	
	-1	($25,305)	91.79	-0.094	($25,850)	7,415.4	****
	-2	($50,610)	91.62	-1	($275,000)	7,446.4	
	-3	($75,915)	91.45	-2	($550,000)	7,480.5	
	-4	($101,220)	91.28	-3	($825,000)	7,514.7	
	-5	($126,525)	91.11	-4	($1,100,000)	7,548.8	
	-6	($151,830)	90.94	-5	($1,375,000)	7,583.0	
	-7	($177,135)	90.77	-6	($1,650,000)	7,617.2	
	-8	($202,440)	90.60	-7	($1,925,000)	7,651.3	
	-9	($227,745)	90.43	-8	($2,200,000)	7,685.5	
	-10	($253,049)	90.26	-9	($2,475,000)	7,719.6	
****	-10	($253,049)	90.26	-10	($2,750,000)	7,753.8	

Equivalent Availability Weighting Factor:	Heat Rate Weighting Factor:
0.78%	7.71%

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GENERATING PERFORMANCE INCENTIVE POINTS TABLE

Duke Energy Florida
January 2019 - December 2019

Unit: Hines 2

	Equivalent Availability (Points)	Fuel Savings/Loss ($)	Equivalent Availability (%)	Average Heat Rate (Points)	Fuel Savings/Loss ($)	Average Heat Rate (BTU/KWH)	
****	10	$81,517	92.88	10	$1,811,231	7,225.7	
	10	$81,517	92.88	9	$1,630,108	7,245.7	
	9	$73,366	92.81	8	$1,448,985	7,265.7	
	8	$65,214	92.74	7	$1,267,862	7,285.8	
	7	$57,062	92.66	6	$1,086,738	7,305.8	
	6	$48,910	92.59	5	$905,615	7,325.9	
	5	$40,759	92.52	4	$724,492	7,345.9	
	4	$32,607	92.45	3	$543,369	7,366.0	
	3	$24,455	92.37	2	$362,246	7,386.0	
	2	$16,303	92.30	1	$181,123	7,406.1	
	1	$8,152	92.23	0	$0	7,426.1	
		$0	92.15	0	$0	7,501.1	
	0	$0	92.15	0	$0	7,576.1	
		$0	92.15	-1	($181,123)	7,596.1	
	-1	($34,725)	92.00	-1.093	($197,968)	7,598.0	****
	-2	($69,450)	91.85	-2	($362,246)	7,616.2	
	-3	($104,175)	91.70	-3	($543,369)	7,636.2	
	-4	($138,900)	91.55	-4	($724,492)	7,656.3	
	-5	($173,625)	91.40	-5	($905,615)	7,676.3	
	-6	($208,350)	91.24	-6	($1,086,738)	7,696.4	
	-7	($243,075)	91.09	-7	($1,267,862)	7,716.4	
	-8	($277,800)	90.94	-8	($1,448,985)	7,736.4	
	-9	($312,525)	90.79	-9	($1,630,108)	7,756.5	
	-10	($347,250)	90.64	-10	($1,811,231)	7,776.5	

Equivalent Availability Weighting Factor:	Heat Rate Weighting Factor:
0.23%	5.08%

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GENERATING PERFORMANCE INCENTIVE POINTS TABLE

Duke Energy Florida
January 2019 - December 2019

Unit: Hines 3

	Equivalent Availability (Points)	Fuel Savings/Loss ($)	Equivalent Availability (%)	Average Heat Rate (Points)	Fuel Savings/Loss ($)	Average Heat Rate (BTU/KWH)	
****	10	$369,550	89.19	10	$1,788,615	7,109.8	
	10	$369,550	89.19	9	$1,609,754	7,126.8	
	9	$332,595	89.08	8	$1,430,892	7,143.7	
	8	$295,640	88.97	7	$1,252,031	7,160.7	
	7	$258,685	88.86	6	$1,073,169	7,177.6	
	6	$221,730	88.75	5	$894,308	7,194.6	
	5	$184,775	88.64	4	$715,446	7,211.5	
	4	$147,820	88.53	3	$536,585	7,228.5	
	3	$110,865	88.42	2	$357,723	7,245.4	
	2	$73,910	88.31	1	$178,862	7,262.4	
	1	$36,955	88.20	0	$0	7,279.3	
		$0	88.09	0.000	$0	7,359.1	****
	0	$0	88.09	0	$0	7,354.3	
		$0	88.09	0	$0	7,429.3	
	-1	($16,937)	87.86	-1	($178,862)	7,446.2	
	-2	($33,873)	87.64	-2	($357,723)	7,463.2	
	-3	($50,810)	87.41	-3	($536,585)	7,480.1	
	-4	($67,746)	87.18	-4	($715,446)	7,497.1	
	-5	($84,683)	86.96	-5	($894,308)	7,514.0	
	-6	($101,619)	86.73	-6	($1,073,169)	7,531.0	
	-7	($118,556)	86.50	-7	($1,252,031)	7,547.9	
	-8	($135,492)	86.28	-8	($1,430,892)	7,564.9	
	-9	($152,429)	86.05	-9	($1,609,754)	7,581.8	
	-10	($169,365)	85.82	-10	($1,788,615)	7,598.8	

Equivalent Availability Weighting Factor:	Heat Rate Weighting Factor:
1.04%	5.02%

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GENERATING PERFORMANCE INCENTIVE POINTS TABLE

Duke Energy Florida
January 2019 - December 2019

Unit: Hines 4

	Equivalent Availability (Points)	Fuel Savings/Loss ($)	Equivalent Availability (%)	Average Heat Rate (Points)	Fuel Savings/Loss ($)	Average Heat Rate (BTU/KWH)	
	-------------	-----------------	-------------	-------------	---------------	-----------	
****	10	$1,026,341	85.53	10	$1,756,447	6,838.4	
	10	$1,026,341	85.53	9	$1,580,802	6,852.1	
	9	$923,707	85.09	8	$1,405,157	6,865.8	
	8	$821,073	84.66	7	$1,229,513	6,879.5	
	7	$718,439	84.22	6	$1,053,868	6,893.2	
	6	$615,805	83.78	5	$878,223	6,906.8	
	5	$513,170	83.35	4	$702,579	6,920.5	
	4	$410,536	82.91	3	$526,934	6,934.2	
	3	$307,902	82.48	2	$351,289	6,947.9	
	2	$205,268	82.04	1	$175,645	6,961.6	
	1	$102,634	81.60	0	$0	6,975.3	
		$0	81.17	0.000	$0	7,008.0	****
	0	$0	81.17	0	$0	7,050.3	
		$0	81.17	0	$0	7,125.3	
	-1	($256,892)	80.27	-1	($175,645)	7,139.0	
	-2	($513,784)	79.36	-2	($351,289)	7,152.7	
	-3	($770,677)	78.46	-3	($526,934)	7,166.4	
	-4	($1,027,569)	77.56	-4	($702,579)	7,180.1	
	-5	($1,284,461)	76.66	-5	($878,223)	7,193.8	
	-6	($1,541,353)	75.75	-6	($1,053,868)	7,207.5	
	-7	($1,798,246)	74.85	-7	($1,229,513)	7,221.2	
	-8	($2,055,138)	73.95	-8	($1,405,157)	7,234.9	
	-9	($2,312,030)	73.04	-9	($1,580,802)	7,248.5	
	-10	($2,568,922)	72.14	-10	($1,756,447)	7,262.2	

Equivalent Availability Weighting Factor:	Heat Rate Weighting Factor:
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2.88%	4.93%

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ACTUAL UNIT PERFORMANCE DATA

Duke Energy Florida

Bartow CC	Jan-19	Feb-19	Mar-19	Apr-19	May-19	Jun-19	Jul-19	Aug-19	Sep-19	Oct-19	Nov-19	Dec-19	Jan-Dec Period
1. EAF	98.52	97.86	62.26	85.22	96.58	99.14	99.54	99.71	96.37	38.49	33.06	74.66	81.69
2. PH	744	672	743	720	744	720	744	744	720	744	721	744	8,760
3. SH	603.9	593.9	485.5	612.3	712.0	695.1	737.1	740.6	670.4	278.8	189.6	483.5	6,802.7
4. RSH	129.0	65.0	8.7	1.3	12.3	20.2	4.2	1.8	23.8	7.6	48.8	71.9	394.7
5. UH	11.0	13.1	248.8	106.4	19.7	4.7	2.7	1.7	25.8	457.6	482.6	188.6	1,562.6
6. POH	0.0	0.0	234.0	70.6	0.0	0.0	0.0	0.0	24.6	457.6	482.5	169.2	1,438.5
7. FOH	8.5	13.1	0.0	14.1	9.2	4.7	1.2	0.7	1.2	0.0	0.1	0.0	52.7
8. MOH	2.5	0.0	14.8	21.7	10.6	0.0	1.5	0.9	0.0	0.0	0.0	19.4	71.4
9. PPOH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
10. LR PP (MW)	0.0	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. PFOH	0.0	21.6	0.0	0.0	15.4	24.8	1.9	1.2	1.8	0.0	0.0	0.0	66.7
12. LR PF (MW)	0.0	67.0	0.0	0.0	187.0	67.0	186.8	187.1	187.6	0.0	0.0	0.0	103.5
13. PMOH	0.0	0.0	182.7	0.0	17.8	0.0	2.3	1.5	0.0	0.0	0.0	0.0	204.4
14. LR PM (MW)	0.0	0.0	187.0	0.0	187.0	0.0	187.2	187.3	0.0	0.0	0.0	0.0	187.0
15. NSC (MW)	1,080	1,080	1,080	1,080	1,080	1,080	1,080	1,080	1,080	1,080	1,080	1,080	1,080
16. OPER MBTU	3,968,623	3,524,794	2,757,930	3,820,788	4,860,440	4,828,905	5,080,089	5,207,503	4,502,703	0	0	2,877,618	41,429,394
17. NET GEN (MWH)	519,987	458,412	365,538	483,493	640,960	630,820	650,624	679,421	574,195	0	0	378,620	5,382,070
18. ANOHR (BTU/KWH)	7,632.2	7,689.1	7,544.9	7,902.5	7,583.1	7,655.0	7,808.0	7,664.6	7,841.8	0.0	0.0	7,600.3	7,697.7
19. NOF (%)	79.72	71.47	69.72	73.11	83.36	84.03	81.73	84.95	73.11	0.00	0.00	81.73	81.34
20. NPC (MW)	1,080	1,080	1,080	1,080	1,080	1,080	1,080	1,080	1,080	1,080	1,080	1,080	1,080
ANOHR EQUATION:	ANOHR=	-25.878	x NOF +	9,778.34									

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ACTUAL UNIT PERFORMANCE DATA

Duke Energy Florida

Crystal River 4	Jan-19	Feb-19	Mar-19	Apr-19	May-19	Jun-19	Jul-19	Aug-19	Sep-19	Oct-19	Nov-19	Dec-19	Jan-Dec Period
1. EAF	95.90	98.58	99.85	99.10	99.94	98.66	98.20	57.66	71.51	81.08	94.93	35.48	85.75
2. PH	744	672	743	720	744	720	744	744	720	744	721	744	8,760
3. SH	249.0	85.3	743.0	720.0	744.0	720.0	742.2	263.4	545.9	606.4	627.6	0.0	6,046.6
4. RSH	465.5	582.4	0.0	0.0	0.0	0.0	0.0	169.8	79.1	0.0	69.4	264.0	1,630.2
5. UH	29.6	4.2	0.0	0.0	0.0	0.0	1.9	310.8	95.1	137.6	24.0	480.0	1,083.2
6. POH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	24.0	480.0	504.0
7. FOH	29.6	4.2	0.0	0.0	0.0	0.0	0.0	310.8	95.1	137.6	0.0	0.0	577.3
8. MOH	0.0	0.0	0.0	0.0	0.0	0.0	1.9	0.0	0.0	0.0	0.0	0.0	1.9
9. PPOH	0.0	6.7	8.5	39.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	54.7
10. LR PP (MW)	0.0	93.0	93.0	108.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	104.1
11. PFOH	2.2	2.9	0.0	1.7	0.0	70.0	71.5	17.6	525.6	9.7	38.8	0.0	740.0
12. LR PF (MW)	284.4	93.0	0.0	188.0	0.0	98.2	115.2	171.0	149.1	231.9	231.1	0.0	147.2
13. PMOH	0.0	31.0	0.0	0.0	3.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	34.3
14. LR PM (MW)	0.0	93.0	0.0	0.0	93.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	93.0
15. NSC (MW)	712	712	712	712	712	712	712	712	712	712	712	712	712
16. OPER MBTU	917,440	391,844	3,216,166	3,273,475	3,558,000	3,435,077	3,020,101	1,170,419	1,954,665	2,891,216	3,214,753	0	27,043,156
17. NET GEN (MWH)	82,152	31,051	323,578	318,328	344,212	326,986	288,033	104,856	181,143	294,269	326,021	0	2,620,629
18. ANOHR (BTU/KWH)	11,167.6	12,619.4	9,939.4	10,283.3	10,336.7	10,505.3	10,485.3	11,162.2	10,790.7	9,825.1	9,860.6	0.0	10,319.3
19. NOF (%)	46.35	51.11	61.17	62.10	64.98	63.78	54.51	55.92	46.61	68.16	72.96	0.00	60.87
20. NPC (MW)	712	712	712	712	712	712	712	712	712	712	712	712	712
ANOHR EQUATION:	ANOHR=	-31.322	x NOF +	12,583.90									

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ACTUAL UNIT PERFORMANCE DATA

Duke Energy Florida

Crystal River 5	Jan-19	Feb-19	Mar-19	Apr-19	May-19	Jun-19	Jul-19	Aug-19	Sep-19	Oct-19	Nov-19	Dec-19	Jan-Dec Period
1. EAF	99.93	78.57	0.00	0.00	0.05	55.99	77.95	92.04	96.29	99.37	75.45	35.48	59.14
2. PH	744	672	743	720	744	720	744	744	720	744	721	744	8,760
3. SH	547.7	0.0	0.0	0.0	0.0	453.3	598.3	551.6	711.6	744.0	527.6	0.0	4,134.0
4. RSH	196.3	528.0	0.0	0.0	0.0	0.0	22.1	192.4	8.4	0.0	25.9	264.0	1,237.1
5. UH	0.0	144.0	743.0	720.0	743.6	266.7	123.7	0.0	0.0	0.0	167.6	480.0	3,388.5
6. POH	0.0	144.0	743.0	720.0	311.0	0.0	0.0	0.0	0.0	0.0	24.0	480.0	2,422.0
7. FOH	0.0	0.0	0.0	0.0	432.6	266.7	0.0	0.0	0.0	0.0	143.6	0.0	842.8
8. MOH	0.0	0.0	0.0	0.0	0.0	0.0	123.7	0.0	0.0	0.0	0.0	0.0	123.7
9. PPOH	0.0	0.0	0.0	0.0	0.0	0.0	4.9	4.5	0.0	0.0	32.5	0.0	41.9
10. LR PP (MW)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	29.0	0.0	0.0	92.8	0.0	75.1
11. PFOH	1.0	0.0	0.0	0.0	0.0	585.3	402.5	435.0	67.7	8.0	40.5	0.0	1,540.0
12. LR PF (MW)	377.0	0.0	0.0	0.0	0.0	60.9	71.2	96.3	280.4	282.0	91.0	0.0	85.4
13. PMOH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	9.0	0.0	0.0	9.0
14. LR PM (MW)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	120.0	0.0	0.0	120.0
15. NSC (MW)	710	710	710	710	710	710	710	710	710	710	710	710	710
16. OPER MBTU	2,006,569	0	0	0	13,291	1,663,716	2,298,627	2,289,894	2,963,269	3,539,459	2,519,396	0	17,294,221
17. NET GEN (MWH)	185,022	0	0	0	0	148,500	226,349	214,475	293,804	365,817	267,021	0	1,700,988
18. ANOHR (BTU/KWH)	10,845.0	0.0	0.0	0.0	0.0	11,203.5	10,155.2	10,676.7	10,085.9	9,675.5	9,435.2	0.0	10,167.2
19. NOF (%)	47.58	0.00	0.00	0.00	0.00	46.14	53.29	54.77	58.15	69.25	71.29	0.00	57.95
20. NPC (MW)	710	710	710	710	710	710	710	710	710	710	710	710	710
ANOHR EQUATION:	ANOHR=	-24.714	x NOF +	11,961.49									

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ACTUAL UNIT PERFORMANCE DATA

Duke Energy Florida

Hines 1	Jan-19	Feb-19	Mar-19	Apr-19	May-19	Jun-19	Jul-19	Aug-19	Sep-19	Oct-19	Nov-19	Dec-19	Jan-Dec Period
1. EAF	47.59	89.85	98.58	39.42	76.09	95.54	98.28	99.88	99.22	100.00	99.91	100.00	87.05
2. PH	744	672	743	720	744	720	744	744	720	744	721	744	8,760
3. SH	356.2	588.3	669.0	260.0	562.9	555.8	705.6	744.0	676.3	726.6	721.0	265.0	6,830.6
4. RSH	25.7	17.4	66.4	28.5	5.0	138.1	25.8	0.0	38.8	17.4	0.0	479.0	842.2
5. UH	362.1	66.2	7.6	431.5	176.1	26.1	12.6	0.0	4.9	0.0	0.0	0.0	1,087.3
6. POH	0.0	0.0	0.0	391.9	158.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	550.6
7. FOH	6.7	0.0	7.6	39.6	5.8	26.1	12.6	0.0	4.9	0.0	0.0	0.0	103.4
8. MOH	355.4	66.2	0.0	0.0	11.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	433.3
9. PPOH	0.0	0.0	12.1	0.0	11.3	0.0	0.0	6.2	5.3	0.0	0.0	0.0	34.9
10. LR PP (MW)	0.0	0.0	68.1	0.0	50.3	0.0	0.0	68.1	63.7	0.0	0.0	0.0	61.7
11. PFOH	166.5	12.0	7.3	26.3	5.4	69.3	12.3	0.0	0.0	0.0	4.0	0.0	303.1
12. LR PF (MW)	82.0	82.0	85.1	78.4	51.3	42.4	8.0	0.0	0.0	0.0	74.5	0.0	69.1
13. PMOH	0.0	0.0	0.0	2.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2.7
14. LR PM (MW)	0.0	0.0	0.0	78.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	78.1
15. NSC (MW)	490	490	490	490	490	490	490	490	490	490	490	490	490
16. OPER MBTU	872,136	1,738,925	1,939,335	666,151	1,699,555	1,636,821	2,139,685	2,310,949	2,006,923	2,318,967	2,438,084	802,632	20,570,163
17. NET GEN (MWH)	114,118	234,944	260,779	88,049	226,948	220,581	284,517	314,211	269,663	315,031	336,111	109,638	2,774,590
18. ANOHR (BTU/KWH)	7,642.4	7,401.4	7,436.7	7,565.7	7,488.7	7,420.5	7,520.4	7,354.8	7,442.3	7,361.1	7,253.8	7,320.7	7,413.8
19. NOF (%)	65.39	81.50	79.55	69.13	82.29	80.99	82.29	86.19	81.38	88.48	95.14	84.44	82.90
20. NPC (MW)	490	490	490	490	490	490	490	490	490	490	490	490	490
ANOHR EQUATION:	ANOHR=	-6.116	x NOF +	7,842.57									

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ACTUAL UNIT PERFORMANCE DATA

Duke Energy Florida

Hines 2	Jan-19	Feb-19	Mar-19	Apr-19	May-19	Jun-19	Jul-19	Aug-19	Sep-19	Oct-19	Nov-19	Dec-19	Jan-Dec Period
1. EAF	99.35	99.93	54.47	100.00	99.98	99.86	99.90	99.83	99.41	99.46	100.00	100.00	95.95
2. PH	744	672	743	720	744	720	744	744	720	744	721	744	8,760
3. SH	522.1	594.2	262.4	703.8	741.6	693.4	743.0	738.0	651.3	669.5	721.0	744.0	7,784.3
4. RSH	217.0	77.8	142.3	16.2	2.4	26.6	1.0	6.0	64.4	71.4	0.0	0.0	625.3
5. UH	4.8	0.0	338.3	0.0	0.0	0.0	0.0	0.0	4.3	3.1	0.0	0.0	350.5
6. POH	0.0	0.0	331.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	331.3
7. FOH	4.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3.6	3.1	0.0	0.0	11.5
8. MOH	0.0	0.0	7.0	0.0	0.0	0.0	0.0	0.0	0.7	0.0	0.0	0.0	7.7
9. PPOH	0.0	4.5	0.0	0.0	1.5	4.0	6.3	10.3	0.0	8.0	0.0	0.0	34.6
10. LR PP (MW)	0.0	51.1	0.0	0.0	56.4	126.0	59.5	62.2	0.0	60.8	0.0	0.0	67.1
11. PFOH	0.0	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. LR PF (MW)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
13. PMOH	0.0	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. LR PM (MW)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
15. NSC (MW)	512	512	512	512	512	512	512	512	512	512	512	512	512
16. OPER MBTU	1,575,600	1,841,414	767,331	2,404,824	2,515,630	2,265,725	2,430,450	2,416,542	2,033,709	2,288,147	2,548,196	2,314,478	25,402,044
17. NET GEN (MWH)	216,465	250,392	94,594	326,935	338,507	305,167	325,431	323,493	271,218	308,402	345,625	311,830	3,418,059
18. ANOHR (BTU/KWH)	7,278.8	7,354.1	8,111.8	7,355.7	7,431.5	7,424.5	7,468.4	7,470.2	7,498.4	7,419.4	7,372.7	7,422.2	7,431.7
19. NOF (%)	80.97	82.31	70.40	90.73	89.15	85.96	85.55	85.61	81.33	89.97	93.63	81.86	85.76
20. NPC (MW)	512	512	512	512	512	512	512	512	512	512	512	512	512
ANOHR EQUATION:	ANOHR=	-16.213	x NOF +	8,725.21									

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ACTUAL UNIT PERFORMANCE DATA

Duke Energy Florida

Hines 3	Jan-19	Feb-19	Mar-19	Apr-19	May-19	Jun-19	Jul-19	Aug-19	Sep-19	Oct-19	Nov-19	Dec-19	Jan-Dec Period
1. EAF	99.51	100.00	99.99	95.45	99.92	99.20	99.54	99.07	97.60	25.65	98.77	99.99	92.78
2. PH	744	672	743	720	744	720	744	744	720	744	721	744	8,760
3. SH	700.1	638.3	343.6	606.6	744.0	604.2	726.7	702.2	640.5	190.9	658.5	395.4	6,950.9
4. RSH	40.7	33.7	399.4	86.5	0.0	112.4	13.9	34.8	63.4	0.0	55.0	348.6	1,188.3
5. UH	3.2	0.0	0.0	26.9	0.0	3.4	3.4	7.0	16.1	553.1	7.6	0.0	620.8
6. POH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	553.1	0.0	0.0	553.1
7. FOH	3.2	0.0	0.0	23.9	0.0	3.4	3.4	0.0	16.1	0.0	7.6	0.0	57.7
8. MOH	0.0	0.0	0.0	3.0	0.0	0.0	0.0	7.0	0.0	0.0	0.0	0.0	10.0
9. PPOH	0.0	0.0	1.0	18.8	5.8	8.0	0.0	0.0	8.0	0.0	0.0	0.7	42.4
10. LR PP (MW)	0.0	0.0	52.2	54.8	55.0	127.3	0.0	0.0	40.2	0.0	0.0	33.5	65.3
11. PFOH	3.3	0.0	0.0	24.5	0.0	3.7	0.0	0.0	3.2	0.0	7.8	0.0	42.4
12. LR PF (MW)	75.3	0.0	0.0	80.4	0.0	49.6	0.0	0.0	83.3	0.0	87.3	0.0	78.8
13. PMOH	0.0	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. LR PM (MW)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
15. NSC (MW)	516	516	516	516	516	516	516	516	516	516	516	516	516
16. OPER MBTU	2,287,431	1,840,031	1,054,849	1,858,493	2,424,687	1,893,691	2,266,552	2,205,309	1,947,286	649,818	2,122,817	1,146,754	21,697,718
17. NET GEN (MWH)	308,437	251,190	147,150	263,134	337,696	262,628	316,781	307,592	266,440	91,572	304,172	154,744	3,011,536
18. ANOHR (BTU/KWH)	7,416.2	7,325.3	7,168.5	7,062.9	7,180.1	7,210.5	7,155.0	7,169.6	7,308.5	7,096.3	6,979.0	7,410.7	7,204.9
19. NOF (%)	85.38	76.26	82.99	84.07	87.96	84.25	84.48	84.89	80.62	92.98	89.52	75.85	83.96
20. NPC (MW)	516	516	516	516	516	516	516	516	516	516	516	516	516
ANOHR EQUATION:	ANOHR=	-19.597	x NOF +	8,845.53									

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ACTUAL UNIT PERFORMANCE DATA

Duke Energy Florida

Hines 4	Jan-19	Feb-19	Mar-19	Apr-19	May-19	Jun-19	Jul-19	Aug-19	Sep-19	Oct-19	Nov-19	Dec-19	Jan-Dec Period
1. EAF	99.64	99.74	98.79	99.78	99.60	93.95	69.25	98.66	99.73	80.44	7.39	98.96	87.18
2. PH	744	672	743	720	744	720	744	744	720	744	721	744	8,760
3. SH	677.2	637.2	680.2	678.2	738.9	603.6	509.8	702.4	685.3	543.0	53.3	734.8	7,243.8
4. RSH	64.8	33.4	62.8	41.8	2.9	72.8	5.4	31.7	32.8	55.8	0.0	1.5	405.7
5. UH	2.0	1.4	0.0	0.0	2.2	43.6	228.8	10.0	2.0	145.2	667.7	7.7	1,110.5
6. POH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	142.8	665.6	6.9	815.3
7. FOH	2.0	1.4	0.0	0.0	2.2	43.6	228.8	0.0	2.0	2.4	2.1	0.8	285.2
8. MOH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	10.0	0.0	0.0	0.0	0.0	10.0
9. PPOH	5.5	0.0	202.9	39.8	5.1	0.0	0.0	0.0	0.0	3.5	0.0	0.0	256.8
10. LR PP (MW)	66.1	0.0	21.2	21.0	59.3	0.0	0.0	0.0	0.0	54.4	0.0	0.0	23.3
11. PFOH	0.0	0.0	8.5	0.0	2.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	10.6
12. LR PF (MW)	0.0	0.0	38.7	0.0	55.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	42.0
13. PMOH	0.0	2.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2.6
14. LR PM (MW)	0.0	78.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	78.1
15. NSC (MW)	516	516	516	516	516	516	516	516	516	516	516	516	516
16. OPER MBTU	2,212,083	1,913,058	2,029,918	2,065,703	2,421,807	1,882,729	1,630,498	2,256,821	2,142,692	1,703,035	122,325	2,268,485	22,649,155
17. NET GEN (MWH)	319,434	276,729	292,615	303,025	342,323	266,653	226,841	313,995	303,106	239,878	17,330	334,807	3,236,736
18. ANOHR (BTU/KWH)	6,925.0	6,913.1	6,937.2	6,816.9	7,074.6	7,060.6	7,187.8	7,187.4	7,069.1	7,099.6	7,058.6	6,775.5	6,997.5
19. NOF (%)	91.42	84.16	83.37	86.59	89.78	85.61	86.24	86.64	85.72	85.61	63.00	88.30	86.59
20. NPC (MW)	516	516	516	516	516	516	516	516	516	516	516	516	516
ANOHR EQUATION:	ANOHR=	-7.869	x NOF +	7,721.26									

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PLANNED OUTAGE SCHEDULES
ACTUAL

Duke Energy Florida
January 2019 - December 2019

Plant/Unit	Planned Outage Dates	Reason for Outage
Bartow CC	03/01 (0000) - 03/25 (2100)	4C: HGP, 4C HRSG & BOP, A&B Exciters
Bartow CC	03/01 (0000) - 04/17 (0856)	4A: Gen Major, 4A HGP, 4A HRSG & BOP, A&B Exciters
Bartow CC	09/28 (0300) - 12/06 (1836)	4S: NERC PRC-025, ST-V, ST-Major HP/IP, DFLP, ST-Gen Minor, BOP
Bartow CC	09/29 (1833) - 01/28/20 (2043)	4B: HGP & Gen Major Rotor Out, Exciters, BOP, ST-V, ST-Major HP/IP, DFLP, ST-Gen Minor
Bartow CC	10/04 (2029) - 11/20 (1111)	4D: HGP & Gen Major Rotor Out, Exciters, BOP, ST-V, ST-Major HP/IP, DFLP, ST-Gen Minor
Bartow CC	11/03 (0707) - 11/12 (0122)	4A: General Gas Turbine Unit Inspection
Bartow CC	11/03 (2345) - 11/10 (2251)	4C: General Gas Turbine Unit Inspection
Crystal River 4	11/30 (0001) - 12/21 (0000)	Control room conversion, flex- clean air work, absorber work
Crystal River 5	02/23 (0000) - 05/13 (2301)	Super heat panels, tube replacement, VFD's, Gen Major, Gen field rewind
Crystal River 5	11/30 (0001) - 12/21 (0000)	Control room conversion, flex- clean air work, absorber work
Hines 1	04/13 (0009) - 05/06 (0000)	CI and CT Gen Minors(A&B), BOP, ST-V
Hines 2	03/02 (0000) - 03/15 (2017)	Balance of Plant Maintenance
Hines 3	10/01 (0100) - 10/24 (2130)	BOP, CT Gen Med Robotic(A&B), L-0 inspection
Hines 4	10/26 (0144) - 12/01 (2033)	BOP, HGP(A), (A) Gen Minor

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Planned Outage Schedule - Actual

Duke Energy Florida

January 2019 - December 2019

	January	February	March	April	May	June	July	August	September	October	November	December
Bartow CC			Major Gas Turbine Overhaull 3/1 – 4/17 47 days						Major Steam Turbine Overhaul 9/28 – 12/6 70 days			
Crystal River 4											Control Room Conversion 11/30 – 12/21 21 days	
Crystal River 5		Major Generator Overhaul 2/23 – 5/13 80 days									Control Room Conversion 11/30 – 12/21 21 days	
Hines 1				Balance of Plant and Minor Generator Maintenance 4/13 – 5/6 23 days								
Hines 2			Balane of Plant Maintenance 3/2 – 3/15 13 days									
Hines 3										Balance of Plant Maintenance, Turbine and Steamer Inspection 10/1 – 10/24 24 days		
Hines 4										Balance of Plant and Minor Generator Maintenance 10/26 – 12/01 37 days		

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GPIF Targets and Ranges for
January through December 2021

STANDARD FORM GPIF SCHEDULES

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FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20200001-EI EXHIBIT: 9
PARTY: DUKE ENERGY FLORIDA – DIRECT
DESCRIPTION: Mary Ingle Lewter MIL-1P

GENERATING PERFORMANCE INCENTIVE FACTOR

REWARD/PENALTY TABLE

ESTIMATED

Duke Energy Florida
Period of: January 2021 - December 2021

Generating Performance Incentive Points (GPIF)	Fuel Saving/Loss ($)	Generating Performance Incentive Factor ($)
10	$25,025,874	$12,512,937
9	$22,523,286	$11,261,643
8	$20,020,699	$10,010,350
7	$17,518,112	$8,759,056
6	$15,015,524	$7,507,762
5	$12,512,937	$6,256,468
4	$10,010,350	$5,005,175
3	$7,507,762	$3,753,881
2	$5,005,175	$2,502,587
1	$2,502,587	$1,251,294
0	$0	$0
-1	($2,867,156)	($1,251,294)
-2	($5,734,311)	($2,502,587)
-3	($8,601,467)	($3,753,881)
-4	($11,468,622)	($5,005,175)
-5	($14,335,778)	($6,256,468)
-6	($17,202,933)	($7,507,762)
-7	($20,070,089)	($8,759,056)
-8	($22,937,244)	($10,010,350)
-9	($25,804,400)	($11,261,643)
-10	($28,671,556)	($12,512,937)

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GENERATION PERFORMANCE INCENTIVE FACTOR

CALCULATION OF MAXIMUM ALLOWED INCENTIVE DOLLARS

ESTIMATED

Duke Energy Florida
Period of: January 2021 - December 2021

1	Beginning of period balance of common equity	$7,519,034,859	
	END OF MONTH BALANCE OF COMMON EQUITY:		
2	Month of JANUARY 2021	$7,567,768,220	
3	Month of FEBRUARY 2021	$7,606,722,199	
4	Month of MARCH 2021	$7,651,606,938	
5	Month of APRIL 2021	$7,692,681,425	
6	Month of MAY 2021	$7,762,480,446	
7	Month of JUNE 2021	$7,871,904,478	
8	Month of JULY 2021	$7,968,310,785	
9	Month of AUGUST 2021	$8,064,213,392	
10	Month of SEPTEMBER 2021	$8,148,549,358	
11	Month of OCTOBER 2021	$8,210,138,862	
12	Month of NOVEMBER 2021	$8,243,678,659	
13	Month of DECEMBER 2021	$8,279,568,269	
14	Average common equity for the period (Summation of LINE 1 through LINE 13 divided by 13)	$7,891,281,376	
15	25 Basis Points	0.0025	
16	Revenue Expansion Factor	75.2740%	
17	Maximum allowed incentive dollars (LINE 14 times LINE 15 divided by LINE 16)	$26,208,523	
18	Jurisdictional Sales	39,588,176	MWH
19	Total Sales	39,605,188	MWH
20	Jurisdictional Separation Factor (LINE 18 divided by LINE 19)	99.96%	
21	Maximum allowed jurisdictional incentive dollars (LINE 17 times LINE 20)	$26,198,039	
22	Incentive Cap (50% of Projected Fuel Savings at 10 GPIF Point Level) From Sheet No. 7.101.1	$12,512,937	
23	Maximum Allowed GPIF Reward (Lesser of Line 21 and Line 22)	$12,512,937	

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GPIF TARGET AND RANGE SUMMARY

Duke Energy Florida
Period of: January 2021 - December 2021

Plant/Unit	Weighting Factor (%)	EAF Target (%)	EAF RANGE Max. (%)	EAF RANGE Min. (%)	Max. Fuel Savings ($000)	Max. Fuel Loss ($000)
Bartow 4	2.09	91.05	93.10	86.85	523	(656)
Crystal River 4	8.74	86.11	92.55	73.41	2,187	(3,743)
Crystal River 5	6.50	81.01	86.28	70.54	1,626	(2,954)
Hines 1	0.77	84.13	85.91	80.55	193	(643)
Hines 2	0.16	94.71	95.40	93.30	41	(222)
Hines 3	0.80	73.66	74.45	72.02	201	(148)
Hines 4	1.27	93.68	94.85	91.21	317	(367)
GPIF System	20.33				5,087	(8,733)

Plant/Unit	Weighting Factor (%)	ANOHR Target (BTU/KWH)	NOF	ANOHR RANGE Min. (BTU/KWH)	ANOHR RANGE Max. (BTU/KWH)	Max. Fuel Savings ($000)	Max. Fuel Loss ($000)
Bartow 4	17.65	7,705	75.1	7,461	7,950	4,418	(4,418)
Crystal River 4	23.32	10,299	69.3	9,714	10,885	5,836	(5,836)
Crystal River 5	20.20	10,434	60.5	9,810	11,058	5,056	(5,056)
Hines 1	2.48	7,470	80.8	7,341	7,599	621	(621)
Hines 2	4.69	7,402	86.3	7,204	7,599	1,173	(1,173)
Hines 3	4.84	7,174	85.9	6,974	7,373	1,210	(1,210)
Hines 4	6.49	6,999	89.1	6,824	7,173	1,625	(1,625)
GPIF System	79.67					19,938	(19,938)

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COMPARISON OF GPIF TARGETS VS. PRIOR PERIODS' ACTUAL PERFORMANCE AVAILABILITY

Duke Energy Florida
Period of: January 2021 - December 2021

Plant/Unit	Target Wt. Factor	Norm. Wt. Factor	Target POF	Target EUOF	Target EUOR	Actual Performance 1st Prior Period Jan-Jun 2020 POF	EUOF	EUOR	Actual Performance 2nd Prior Period Jan-Dec 2019 POF	EUOF	EUOR
Bartow 4	2.09	10.28	4.59	4.36	4.36	2.73	2.15	2.42	16.42	1.89	2.39
Crystal River 4	8.74	42.99	0.00	13.89	14.50	46.27	4.04	23.08	5.75	8.41	11.12
Crystal River 5	6.50	31.95	7.67	11.32	12.65	0.00	5.74	12.02	27.65	13.16	22.61
Hines 1	0.77	3.79	12.05	3.82	6.57	0.00	10.99	12.97	6.29	6.62	7.87
Hines 2	0.16	0.80	3.84	1.45	2.39	27.70	7.10	10.52	3.78	0.22	0.25
Hines 3	0.80	3.96	24.66	1.68	2.80	0.00	4.03	4.74	6.31	0.85	1.06
Hines 4	1.27	6.23	3.84	2.49	2.77	0.00	2.14	2.28	9.31	3.38	3.93
GPIF System Wghtd. Avg.	20.33	100.00	4.63	10.41	11.27	20.39	4.56	14.91	14.09	8.51	12.84

Plant/Unit	Actual Performance 3rd Prior Period Jan-Dec 2018 POF	EUOF	EUOR	Actual Performance 4th Prior Period Jan-Dec 2017 POF	EUOF	EUOR	Actual Performance 5th Prior Period Jan-Dec 2016 POF	EUOF	EUOR
Bartow 4	1.86	6.00	6.33	1.43	10.97	11.43	10.34	8.02	9.11
Crystal River 4	12.23	6.20	7.73	0.00	16.97	16.97	8.44	5.70	6.23
Crystal River 5	4.01	8.92	9.30	19.56	5.13	6.37	2.07	5.56	5.76
Hines 1	6.68	3.56	4.23	7.71	3.08	3.57	10.11	1.78	2.02
Hines 2	5.03	1.52	1.78	7.93	0.61	0.74	8.73	3.81	4.43
Hines 3	8.59	0.90	1.10	7.18	4.93	5.68	15.10	1.79	2.17
Hines 4	6.71	1.28	1.51	9.04	2.01	2.34	7.75	26.15	28.61
GPIF System Wghtd. Avg.	7.78	6.40	7.26	7.60	10.50	11.02	6.89	6.85	7.44

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COMPARISON OF GPIF TARGETS VS. PRIOR PERIODS' ACTUAL PERFORMANCE
AVERAGE NET OPERATING HEAT RATE

Duke Energy Florida
Period of: January 2021 - December 2021

Plant/Unit	Target Wt. Factor	Norm. Wt. Factor	Average Heat Rate Target	1st Prior HR Jan 2019 - Dec 2019	2nd Prior HR Jan 2018 - Dec 2018	3rd Prior HR Jan 2017 - Dec 2017
Bartow 4	17.65	22.16	7,705	7,724	7,698	7,792
Crystal River 4	23.32	29.27	10,299	10,160	10,234	10,456
Crystal River 5	20.20	25.36	10,434	10,206	10,445	10,505
Hines 1	2.48	3.11	7,470	7,445	7,488	7,368
Hines 2	4.69	5.88	7,402	7,406	7,377	7,396
Hines 3	4.84	6.07	7,174	7,179	7,232	7,094
Hines 4	6.49	8.15	6,999	6,986	6,985	7,028
			-	-	-	-
			-	-	-	-
			-	-	-	-
			-	-	-	-
			-	-	-	-
GPIF System Weighted Avg.	79.67	100.00	9,041	8,946	9,025	9,119

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DERIVATION OF WEIGHTING FACTORS

Duke Energy Florida
Period of: January 2021 - December 2021

Unit Performance Indicator	Production Costing Simulation Fuel Cost ($000) At Target (1)	At Maximum Improvement (2)	Savings (3)	Weighting Factor (% of Savings)
Bartow 4 EAF	1,742,756	1,742,233	523	2.09
Bartow 4 HR	1,742,756	1,738,338	4,418	17.65
Crystal River 4 EAF	1,742,756	1,740,569	2,187	8.74
Crystal River 4 HR	1,742,756	1,736,920	5,836	23.32
Crystal River 5 EAF	1,742,756	1,741,131	1,626	6.50
Crystal River 5 HR	1,742,756	1,737,700	5,056	20.20
Hines 1 EAF	1,742,756	1,742,563	193	0.77
Hines 1 HR	1,742,756	1,742,135	621	2.48
Hines 2 EAF	1,742,756	1,742,716	41	0.16
Hines 2 HR	1,742,756	1,741,583	1,173	4.69
Hines 3 EAF	1,742,756	1,742,555	201	0.80
Hines 3 HR	1,742,756	1,741,546	1,210	4.84
Hines 4 EAF	1,742,756	1,742,439	317	1.27
Hines 4 HR	1,742,756	1,741,131	1,625	6.49

1. Fuel Adjustment Base Case - all unit performance indicators at Target.
2. All other unit performance indicators at Target.
3. Expressed in replacement costs.

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INCENTIVE POINTS TABLES

GENERATING PERFORMANCE INCENTIVE POINTS TABLE

Duke Energy Florida
Period of: January 2021 - December 2021

Bartow 4

Equivalent Availability (Points)	Fuel Savings/Loss ($)	Equivalent Availability (%)	Average Heat Rate (Points)	Fuel Savings/Loss ($)	Average Heat Rate (BTU/KWH)
10	$522,961	93.10	10	$4,417,564	7,460.6
9	$470,665	92.90	9	$3,975,807	7,477.6
8	$418,369	92.69	8	$3,534,051	7,494.5
7	$366,073	92.49	7	$3,092,294	7,511.5
6	$313,777	92.28	6	$2,650,538	7,528.5
5	$261,481	92.08	5	$2,208,782	7,545.5
4	$209,184	91.87	4	$1,767,025	7,562.5
3	$156,888	91.67	3	$1,325,269	7,579.5
2	$104,592	91.46	2	$883,513	7,596.5
1	$52,296	91.26	1	$441,756	7,613.5
					7,630.5
0	$0	91.05	0	$0	7,705.5
					7,780.5
-1	($65,645)	90.63	-1	($441,756)	7,797.5
-2	($131,290)	90.21	-2	($883,513)	7,814.5
-3	($196,935)	89.79	-3	($1,325,269)	7,831.5
-4	($262,580)	89.37	-4	($1,767,025)	7,848.5
-5	($328,225)	88.95	-5	($2,208,782)	7,865.4
-6	($393,870)	88.53	-6	($2,650,538)	7,882.4
-7	($459,515)	88.11	-7	($3,092,294)	7,899.4
-8	($525,160)	87.69	-8	($3,534,051)	7,916.4
-9	($590,805)	87.27	-9	($3,975,807)	7,933.4
-10	($656,450)	86.85	-10	($4,417,564)	7,950.4

Equivalent Availability Weighting Factor:	Heat Rate Weighting Factor:
2.09%	17.65%

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GENERATING PERFORMANCE INCENTIVE POINTS TABLE

Duke Energy Florida
Period of: January 2021 - December 2021

Crystal River 4

Equivalent Availability (Points)	Fuel Savings/Loss ($)	Equivalent Availability (%)	Average Heat Rate (Points)	Fuel Savings/Loss ($)	Average Heat Rate (BTU/KWH)
10	$2,187,129	92.55	10	$5,835,797	9,714.1
9	$1,968,416	91.90	9	$5,252,217	9,765.1
8	$1,749,703	91.26	8	$4,668,638	9,816.1
7	$1,530,990	90.62	7	$4,085,058	9,867.1
6	$1,312,277	89.97	6	$3,501,478	9,918.2
5	$1,093,564	89.33	5	$2,917,899	9,969.2
4	$874,851	88.69	4	$2,334,319	10,020.2
3	$656,139	88.04	3	$1,750,739	10,071.2
2	$437,426	87.40	2	$1,167,159	10,122.3
1	$218,713	86.76	1	$583,580	10,173.3
					10,224.3
0	$0	86.11	0	$0	10,299.3
					10,374.3
-1	($374,281)	84.84	-1	($583,580)	10,425.4
-2	($748,561)	83.57	-2	($1,167,159)	10,476.4
-3	($1,122,842)	82.30	-3	($1,750,739)	10,527.4
-4	($1,497,122)	81.03	-4	($2,334,319)	10,578.4
-5	($1,871,403)	79.76	-5	($2,917,899)	10,629.5
-6	($2,245,684)	78.49	-6	($3,501,478)	10,680.5
-7	($2,619,964)	77.22	-7	($4,085,058)	10,731.5
-8	($2,994,245)	75.95	-8	($4,668,638)	10,782.5
-9	($3,368,525)	74.68	-9	($5,252,217)	10,833.6
-10	($3,742,806)	73.41	-10	($5,835,797)	10,884.6

Equivalent Availability Weighting Factor:	Heat Rate Weighting Factor:
8.74%	23.32%

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GENERATING PERFORMANCE INCENTIVE POINTS TABLE

Duke Energy Florida
Period of: January 2021 - December 2021

Crystal River 5

Equivalent Availability (Points)	Fuel Savings/Loss ($)	Equivalent Availability (%)	Average Heat Rate (Points)	Fuel Savings/Loss ($)	Average Heat Rate (BTU/KWH)
10	$1,625,520	86.28	10	$5,055,932	9,810.2
9	$1,462,968	85.75	9	$4,550,339	9,865.1
8	$1,300,416	85.22	8	$4,044,746	9,919.9
7	$1,137,864	84.70	7	$3,539,152	9,974.8
6	$975,312	84.17	6	$3,033,559	10,029.7
5	$812,760	83.64	5	$2,527,966	10,084.5
4	$650,208	83.12	4	$2,022,373	10,139.4
3	$487,656	82.59	3	$1,516,780	10,194.3
2	$325,104	82.07	2	$1,011,186	10,249.1
1	$162,552	81.54	1	$505,593	10,304.0
					10,358.9
0	$0	81.01	0	$0	10,433.9
					10,508.9
-1	($295,406)	79.97	-1	($505,593)	10,563.7
-2	($590,812)	78.92	-2	($1,011,186)	10,618.6
-3	($886,217)	77.87	-3	($1,516,780)	10,673.5
-4	($1,181,623)	76.82	-4	($2,022,373)	10,728.3
-5	($1,477,029)	75.77	-5	($2,527,966)	10,783.2
-6	($1,772,435)	74.73	-6	($3,033,559)	10,838.1
-7	($2,067,841)	73.68	-7	($3,539,152)	10,892.9
-8	($2,363,246)	72.63	-8	($4,044,746)	10,947.8
-9	($2,658,652)	71.58	-9	($4,550,339)	11,002.7
-10	($2,954,058)	70.54	-10	($5,055,932)	11,057.5

Equivalent Availability Weighting Factor:	Heat Rate Weighting Factor:
6.50%	20.20%

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GENERATING PERFORMANCE INCENTIVE POINTS TABLE

Duke Energy Florida
Period of: January 2021 - December 2021

Hines 1

Equivalent Availability (Points)	Fuel Savings/Loss ($)	Equivalent Availability (%)	Average Heat Rate (Points)	Fuel Savings/Loss ($)	Average Heat Rate (BTU/KWH)
10	$192,952	85.91	10	$620,607	7,340.5
9	$173,657	85.73	9	$558,547	7,346.0
8	$154,362	85.55	8	$496,486	7,351.4
7	$135,066	85.38	7	$434,425	7,356.9
6	$115,771	85.20	6	$372,364	7,362.3
5	$96,476	85.02	5	$310,304	7,367.8
4	$77,181	84.84	4	$248,243	7,373.2
3	$57,886	84.66	3	$186,182	7,378.6
2	$38,590	84.48	2	$124,121	7,384.1
1	$19,295	84.31	1	$62,061	7,389.5
					7,395.0
0	$0	84.13	0	$0	7,470.0
					7,545.0
-1	($64,260)	83.77	-1	($62,061)	7,550.4
-2	($128,520)	83.41	-2	($124,121)	7,555.9
-3	($192,780)	83.05	-3	($186,182)	7,561.3
-4	($257,040)	82.70	-4	($248,243)	7,566.8
-5	($321,300)	82.34	-5	($310,304)	7,572.2
-6	($385,560)	81.98	-6	($372,364)	7,577.7
-7	($449,820)	81.62	-7	($434,425)	7,583.1
-8	($514,080)	81.26	-8	($496,486)	7,588.5
-9	($578,340)	80.91	-9	($558,547)	7,594.0
-10	($642,600)	80.55	-10	($620,607)	7,599.4

Equivalent Availability Weighting Factor:	Heat Rate Weighting Factor:
0.77%	2.48%

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GENERATING PERFORMANCE INCENTIVE POINTS TABLE

Duke Energy Florida
Period of: January 2021 - December 2021

Hines 2

Equivalent Availability (Points)	Fuel Savings/Loss ($)	Equivalent Availability (%)	Average Heat Rate (Points)	Fuel Savings/Loss ($)	Average Heat Rate (BTU/KWH)
10	$40,503	95.40	10	$1,173,063	7,204.5
9	$36,452	95.33	9	$1,055,757	7,216.7
8	$32,402	95.26	8	$938,451	7,228.9
7	$28,352	95.19	7	$821,144	7,241.2
6	$24,302	95.13	6	$703,838	7,253.4
5	$20,251	95.06	5	$586,532	7,265.6
4	$16,201	94.99	4	$469,225	7,277.9
3	$12,151	94.92	3	$351,919	7,290.1
2	$8,101	94.85	2	$234,613	7,302.3
1	$4,050	94.78	1	$117,306	7,314.6
					7,326.8
0	$0	94.71	0	$0	7,401.8
					7,476.8
-1	($22,203)	94.57	-1	($117,306)	7,489.1
-2	($44,406)	94.43	-2	($234,613)	7,501.3
-3	($66,609)	94.29	-3	($351,919)	7,513.5
-4	($88,812)	94.15	-4	($469,225)	7,525.8
-5	($111,015)	94.01	-5	($586,532)	7,538.0
-6	($133,218)	93.86	-6	($703,838)	7,550.2
-7	($155,421)	93.72	-7	($821,144)	7,562.5
-8	($177,624)	93.58	-8	($938,451)	7,574.7
-9	($199,827)	93.44	-9	($1,055,757)	7,586.9
-10	($222,030)	93.30	-10	($1,173,063)	7,599.2

Equivalent Availability Weighting Factor:	Heat Rate Weighting Factor:
0.16%	4.69%

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GENERATING PERFORMANCE INCENTIVE POINTS TABLE

Duke Energy Florida
Period of: January 2021 - December 2021

Hines 3

Equivalent Availability (Points)	Fuel Savings/Loss ($)	Equivalent Availability (%)	Average Heat Rate (Points)	Fuel Savings/Loss ($)	Average Heat Rate (BTU/KWH)
10	$201,411	74.45	10	$1,210,451	6,974.4
9	$181,270	74.37	9	$1,089,406	6,986.9
8	$161,129	74.29	8	$968,361	6,999.3
7	$140,988	74.21	7	$847,316	7,011.7
6	$120,847	74.13	6	$726,271	7,024.1
5	$100,706	74.06	5	$605,226	7,036.5
4	$80,564	73.98	4	$484,180	7,049.0
3	$60,423	73.90	3	$363,135	7,061.4
2	$40,282	73.82	2	$242,090	7,073.8
1	$20,141	73.74	1	$121,045	7,086.2
					7,098.6
0	$0	73.66	0	$0	7,173.6
					7,248.6
-1	($14,830)	73.49	-1	($121,045)	7,261.0
-2	($29,660)	73.33	-2	($242,090)	7,273.5
-3	($44,490)	73.17	-3	($363,135)	7,285.9
-4	($59,320)	73.00	-4	($484,180)	7,298.3
-5	($74,149)	72.84	-5	($605,226)	7,310.7
-6	($88,979)	72.67	-6	($726,271)	7,323.1
-7	($103,809)	72.51	-7	($847,316)	7,335.6
-8	($118,639)	72.35	-8	($968,361)	7,348.0
-9	($133,469)	72.18	-9	($1,089,406)	7,360.4
-10	($148,299)	72.02	-10	($1,210,451)	7,372.8

Equivalent Availability Weighting Factor:	Heat Rate Weighting Factor:
0.80%	4.84%

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GENERATING PERFORMANCE INCENTIVE POINTS TABLE

Duke Energy Florida
Period of: January 2021 - December 2021

Hines 4

Equivalent Availability (Points)	Fuel Savings/Loss ($)	Equivalent Availability (%)	Average Heat Rate (Points)	Fuel Savings/Loss ($)	Average Heat Rate (BTU/KWH)
10	$316,970	94.85	10	$1,625,014	6,824.3
9	$285,273	94.74	9	$1,462,513	6,834.3
8	$253,576	94.62	8	$1,300,011	6,844.2
7	$221,879	94.50	7	$1,137,510	6,854.1
6	$190,182	94.38	6	$975,008	6,864.0
5	$158,485	94.26	5	$812,507	6,873.9
4	$126,788	94.15	4	$650,006	6,883.8
3	$95,091	94.03	3	$487,504	6,893.8
2	$63,394	93.91	2	$325,003	6,903.7
1	$31,697	93.79	1	$162,501	6,913.6
					6,923.5
0	$0	93.68	0	$0	6,998.5
					7,073.5
-1	($36,688)	93.43	-1	($162,501)	7,083.4
-2	($73,377)	93.18	-2	($325,003)	7,093.4
-3	($110,065)	92.94	-3	($487,504)	7,103.3
-4	($146,753)	92.69	-4	($650,006)	7,113.2
-5	($183,442)	92.44	-5	($812,507)	7,123.1
-6	($220,130)	92.20	-6	($975,008)	7,133.0
-7	($256,819)	91.95	-7	($1,137,510)	7,142.9
-8	($293,507)	91.70	-8	($1,300,011)	7,152.9
-9	($330,195)	91.46	-9	($1,462,513)	7,162.8
-10	($366,884)	91.21	-10	($1,625,014)	7,172.7

Equivalent Availability Weighting Factor:	Heat Rate Weighting Factor:
1.27%	6.49%

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UNIT PERFORMANCE DATA

ESTIMATED UNIT PERFORMANCE DATA

Duke Energy Florida
Period of: January 2021 - December 2021

PLANT/UNIT **Bartow 4**	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Year
1. EAF	95.64	95.64	90.00	95.64	95.64	95.64	95.64	95.64	95.64	81.12	60.64	95.64	91.05
2. POF	0.00	0.00	5.65	0.00	0.00	0.00	0.00	0.00	0.00	14.52	35.00	0.00	4.59
3. EUOF	4.36	4.36	4.36	4.36	4.36	4.36	4.36	4.36	4.36	4.36	4.36	4.36	4.36
4. EUOR	4.36	4.36	4.36	4.36	4.36	4.36	4.36	4.36	4.36	4.36	4.36	4.36	4.36
5. PH	744	672	744	720	744	720	744	744	720	744	720	744	8,760
6. SH	718.2	648.7	718.2	695.1	718.2	695.1	718.2	718.2	695.1	718.2	695.1	718.2	8,456.6
7. RSH	0.0	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. UH	25.8	23.3	25.8	24.9	25.8	24.9	25.8	25.8	24.9	25.8	24.9	25.8	303.4
9. POH & PPOH	0.0	0.0	42.0	0.0	0.0	0.0	0.0	0.0	0.0	108.0	252.0	0.0	402.0
10. FOH & PFOH	23.9	21.6	23.9	23.2	23.9	23.2	23.9	23.9	23.2	23.9	23.2	23.9	281.8
11. MOH & PMOH	8.5	7.7	8.5	8.2	8.5	8.2	8.5	8.5	8.2	8.5	8.2	8.5	100.0
12. Oper. Btu(MBtu)	4,622,994	4,446,396	4,759,862	4,980,988	5,277,762	5,071,417	5,209,114	5,197,972	5,038,740	4,411,974	3,331,083	4,797,808	57,169,311
13. Net Gen. (MWH)	598,899.0	577,340.0	617,273.0	647,868.0	687,161.0	660,105.0	677,864.0	676,356.0	655,681.0	570,648.0	427,730.0	622,374.0	7,419,299.0
14. ANOHR (Btu/KWH)	7,719	7,702	7,711	7,688	7,681	7,683	7,685	7,685	7,685	7,732	7,788	7,709	7,705
15. NOF (%)	71.3	76.1	73.5	79.7	81.8	81.2	80.7	80.6	80.7	68.0	52.6	74.1	75.1
16. NSC (MW)	1169	1169	1169	1169	1169	1169	1169	1169	1169	1169	1169	1169	1169
17. ANOHR Equation	ANOHR=	-3.674 x NOF +		7,981.2									

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ESTIMATED UNIT PERFORMANCE DATA

Duke Energy Florida
Period of: January 2021 - December 2021

PLANT/UNIT **Crystal River 4**	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Year
1. EAF	86.11	85.99	85.50	85.50	85.50	85.50	85.50	86.12	86.10	87.15	86.77	87.55	86.11
2. POF	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
3. EUOF	13.89	14.01	14.50	14.50	14.50	14.50	14.50	13.88	13.90	12.85	13.23	12.45	13.89
4. EUOR	14.50	14.50	14.50	14.50	14.50	14.50	14.50	14.50	14.50	14.50	14.50	14.50	14.50
5. PH	744	672	744	720	744	720	744	744	720	744	720	744	8,760
6. SH	622.3	566.9	649.7	628.7	649.7	628.7	649.7	621.9	602.5	575.7	573.9	557.7	7,327.5
7. RSH	31.4	22.8	0.0	0.0	0.0	0.0	0.0	31.8	30.0	84.8	62.8	105.4	369.0
8. UH	90.3	82.3	94.3	91.3	94.3	91.3	94.3	90.3	87.5	83.5	83.3	80.9	1063.5
9. POH & PPOH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
10. FOH & PFOH	89.5	81.6	93.5	90.5	93.5	90.5	93.5	89.5	86.7	82.8	82.6	80.2	1054.4
11. MOH & PMOH	13.8	12.6	14.4	13.9	14.4	13.9	14.4	13.8	13.3	12.7	12.7	12.3	162.2
12. Oper. Btu(MBtu)	3,215,751	2,828,950	3,372,503	2,817,665	3,240,145	3,254,350	3,553,366	3,377,493	3,134,027	2,916,779	2,912,723	2,577,037	37,232,316
13. Net Gen. (MWH)	313,507.0	273,511.0	329,152.0	266,333.0	313,224.0	317,395.0	351,556.0	333,513.0	306,030.0	283,012.0	282,729.0	245,063.0	3,615,025.0
14. ANOHR (Btu/KWH)	10,257	10,343	10,246	10,579	10,344	10,253	10,108	10,127	10,241	10,306	10,302	10,516	10,299
15. NOF (%)	70.8	67.8	71.2	59.5	67.7	70.9	76.0	75.3	71.3	69.1	69.2	61.7	69.3
16. NSC (MW)	712	712	712	712	712	712	712	712	712	712	712	712	712
17. ANOHR Equation	ANOHR=	-28.596 x NOF +		12,280.8									

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ESTIMATED UNIT PERFORMANCE DATA

Duke Energy Florida
Period of: January 2021 - December 2021

PLANT/UNIT **Crystal River 5**	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Year
1. EAF	87.71	87.71	87.55	6.09	88.83	88.59	87.35	87.35	87.35	87.35	87.35	87.80	81.01
2. POF	0.00	0.00	0.00	93.33	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	7.67
3. EUOF	12.29	12.29	12.45	0.57	11.17	11.41	12.65	12.65	12.65	12.65	12.65	12.20	11.32
4. EUOR	12.65	12.65	12.65	12.65	12.65	12.65	12.65	12.65	12.65	12.65	12.65	12.65	12.65
5. PH	744	672	744	720	744	720	744	744	720	744	720	744	8,760
6. SH	643.3	581.4	652.0	29.0	584.8	578.3	662.2	662.2	640.8	662.2	640.8	638.5	6,975.6
7. RSH	21.2	18.8	11.4	15.4	87.0	70.2	0.0	0.0	0.0	0.0	0.0	26.6	250.6
8. UH	79.5	71.8	80.6	675.6	72.2	71.5	81.8	81.8	79.2	81.8	79.2	78.9	1533.8
9. POH & PPOH	0.0	0.0	0.0	672.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	672.0
10. FOH & PFOH	79.4	71.8	80.5	3.6	72.2	71.4	81.7	81.7	79.1	81.7	79.1	78.8	861.1
11. MOH & PMOH	12.0	10.8	12.2	0.5	10.9	10.8	12.4	12.4	12.0	12.4	12.0	11.9	130.1
12. Oper. Btu(MBtu)	2,958,617	2,509,458	2,951,833	95,143	2,430,036	2,580,728	3,014,657	3,152,939	2,739,745	3,250,598	2,985,280	2,581,381	31,274,120
13. Net Gen. (MWH)	284,959.0	238,840.0	283,433.0	8,700.0	229,768.0	247,121.0	289,780.0	305,827.0	260,317.0	317,376.0	288,266.0	242,977.0	2,997,364.0
14. ANOHR (Btu/KWH)	10,383	10,507	10,415	10,936	10,576	10,443	10,403	10,310	10,525	10,242	10,356	10,624	10,434
15. NOF (%)	62.4	57.9	61.2	42.2	55.3	60.2	61.6	65.0	57.2	67.5	63.4	53.6	60.5
16. NSC (MW)	710	710	710	710	710	710	710	710	710	710	710	710	710
17. ANOHR Equation	ANOHR=	-27.456	x NOF +	12,095.5									

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ESTIMATED UNIT PERFORMANCE DATA

Duke Energy Florida
Period of: January 2021 - December 2021

PLANT/UNIT **Hines 1**	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Year
1. EAF	98.99	99.29	95.51	41.97	12.15	93.65	93.64	93.55	93.60	93.59	95.35	99.33	84.13
2. POF	0.00	0.00	0.00	56.67	87.10	0.00	0.00	0.00	0.00	0.00	0.00	0.00	12.05
3. EUOF	1.01	0.71	4.49	1.37	0.75	6.35	6.36	6.45	6.40	6.41	4.65	0.67	3.82
4. EUOR	6.57	6.57	6.57	6.57	6.57	6.57	6.57	6.57	6.57	6.57	6.57	6.57	6.57
5. PH	744	672	744	720	744	720	744	744	720	744	720	744	8,760
6. SH	107.6	68.1	476.4	140.4	79.7	652.0	675.3	685.2	657.5	680.3	478.2	71.1	4,771.8
7. RSH	629.2	599.4	235.8	162.2	11.0	24.4	23.6	13.0	18.6	18.2	209.8	668.2	2613.4
8. UH	7.2	4.5	31.8	417.4	653.3	43.6	45.1	45.8	43.9	45.5	32.0	4.7	1374.8
9. POH & PPOH	0.0	0.0	0.0	408.0	648.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1056.0
10. FOH & PFOH	3.3	2.1	14.6	4.3	2.4	20.0	20.7	21.1	20.2	20.9	14.7	2.2	146.6
11. MOH & PMOH	4.2	2.7	18.7	5.5	3.1	25.7	26.6	27.0	25.9	26.8	18.8	2.8	187.8
12. Oper. Btu(MBtu)	332,636	196,469	1,171,283	329,049	224,335	1,924,779	2,080,700	2,019,397	1,955,542	2,145,381	1,467,363	239,397	14,105,825
13. Net Gen. (MWH)	44,982.0	26,169.0	151,484.0	42,240.0	29,728.0	257,590.0	281,159.0	270,156.0	262,139.0	291,508.0	198,085.0	33,094.0	1,888,334.0
14. ANOHR (Btu/KWH)	7,395	7,508	7,732	7,790	7,546	7,472	7,400	7,475	7,460	7,360	7,408	7,234	7,470
15. NOF (%)	85.3	78.5	64.9	61.4	76.1	80.6	85.0	80.5	81.4	87.4	84.5	95.1	80.8
16. NSC (MW)	490	490	490	490	490	490	490	490	490	490	490	490	490
17. ANOHR Equation	ANOHR=	-16.520	x NOF +	8,804.1									

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ESTIMATED UNIT PERFORMANCE DATA

Duke Energy Florida
Period of: January 2021 - December 2021

PLANT/UNIT **Hines 2**	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Year
1. EAF	99.78	99.73	99.52	98.11	97.69	97.75	97.73	97.67	97.66	97.63	52.92	99.83	94.71
2. POF	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	46.67	0.00	3.84
3. EUOF	0.22	0.27	0.48	1.89	2.31	2.25	2.27	2.33	2.34	2.37	0.42	0.17	1.45
4. EUOR	2.39	2.39	2.39	2.39	2.39	2.39	2.39	2.39	2.39	2.39	2.39	2.39	2.39
5. PH	744	672	744	720	744	720	744	744	720	744	720	744	8,760
6. SH	68.4	74.7	145.3	557.8	703.2	663.3	691.3	711.3	688.7	723.4	122.7	52.2	5,202.3
7. RSH	674.2	595.8	595.8	151.0	26.6	43.4	38.8	18.4	17.4	6.0	258.8	690.8	3117.0
8. UH	1.4	1.5	2.9	11.2	14.2	13.3	13.9	14.3	13.9	14.6	338.5	1.0	440.7
9. POH & PPOH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	336.0	0.0	336.0
10. FOH & PFOH	1.0	1.1	2.2	8.3	10.5	9.9	10.3	10.6	10.3	10.8	1.8	0.8	77.5
11. MOH & PMOH	0.7	0.7	1.4	5.3	6.7	6.3	6.6	6.8	6.6	6.9	1.2	0.5	49.5
12. Oper. Btu(MBtu)	221,389	202,532	409,030	1,853,766	2,343,750	2,254,524	2,338,377	2,418,085	2,356,813	2,472,954	389,106	143,187	17,410,295
13. Net Gen. (MWH)	29,725.0	26,451.0	53,704.0	250,121.0	316,397.0	305,500.0	316,564.0	327,671.0	319,776.0	335,465.0	52,057.0	18,733.0	2,352,164.0
14. ANOHR (Btu/KWH)	7,448	7,657	7,616	7,411	7,408	7,380	7,387	7,380	7,370	7,372	7,475	7,644	7,402
15. NOF (%)	82.9	67.6	70.5	85.6	85.9	87.9	87.4	87.9	88.6	88.5	80.9	68.6	86.3
16. NSC (MW)	524	524	524	524	524	524	524	524	524	524	524	524	524
17. ANOHR Equation	ANOHR=	-13.633 x NOF +		8,578.2									

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ESTIMATED UNIT PERFORMANCE DATA

Duke Energy Florida
Period of: January 2021 - December 2021

PLANT/UNIT **Hines 3**	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Year
1. EAF	99.06	42.42	0.00	0.00	56.47	97.21	97.21	97.22	97.21	97.21	97.87	98.91	73.66
2. POF	0.00	57.14	100.00	100.00	41.94	0.00	0.00	0.00	0.00	0.00	0.00	0.00	24.66
3. EUOF	0.94	0.44	0.00	0.00	1.59	2.79	2.79	2.78	2.79	2.79	2.13	1.09	1.68
4. EUOR	2.80	2.80	0.00	0.00	2.80	2.80	2.80	2.80	2.80	2.80	2.80	2.80	2.80
5. PH	744	672	744	720	744	720	744	744	720	744	720	744	8,760
6. SH	242.7	101.9	0.0	0.0	411.4	697.9	721.6	719.2	697.9	720.5	533.5	282.0	5,128.7
7. RSH	494.9	183.4	0.0	0.0	9.8	3.7	3.4	5.9	3.7	4.6	172.5	454.6	1336.5
8. UH	6.4	386.7	744.0	720.0	322.8	18.4	19.0	18.9	18.4	18.9	14.0	7.4	2294.8
9. POH & PPOH	0.0	384.0	744.0	720.0	312.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2160.0
10. FOH & PFOH	4.0	1.7	0.0	0.0	6.8	11.6	12.0	11.9	11.6	12.0	8.9	4.7	85.1
11. MOH & PMOH	3.0	1.2	0.0	0.0	5.0	8.5	8.8	8.8	8.5	8.8	6.5	3.4	62.4
12. Oper. Btu(MBtu)	707,267	306,750	-	-	1,287,912	2,266,566	2,388,344	2,321,876	2,277,816	2,382,573	1,749,619	758,702	16,457,804
13. Net Gen. (MWH)	96,585.0	42,164.0	-	-	178,531.0	316,842.0	335,396.0	324,125.0	318,790.0	334,520.0	245,156.0	102,100.0	2,294,209.0
14. ANOHR (Btu/KWH)	7,323	7,275	-	-	7,214	7,154	7,121	7,164	7,145	7,122	7,137	7,431	7,174
15. NOF (%)	76.4	79.4	0.0	0.0	83.3	87.1	89.2	86.5	87.7	89.1	88.2	69.5	85.9
16. NSC (MW)	521	521	521	521	521	521	521	521	521	521	521	521	521
17. ANOHR Equation	ANOHR=	-15.726 x NOF +		8,523.9									

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ESTIMATED UNIT PERFORMANCE DATA

Duke Energy Florida
Period of: January 2021 - December 2021

PLANT/UNIT **Hines 4**	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Year
1. EAF	98.11	98.06	97.31	97.25	97.24	97.24	97.23	97.25	97.24	69.01	81.05	97.49	93.68
2. POF	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	29.03	16.67	0.00	3.84
3. EUOF	1.89	1.94	2.69	2.75	2.76	2.76	2.77	2.75	2.76	1.96	2.29	2.51	2.49
4. EUOR	2.77	2.77	2.77	2.77	2.77	2.77	2.77	2.77	2.77	2.77	2.77	2.77	2.77
5. PH	744	672	744	720	744	720	744	744	720	744	720	744	8,760
6. SH	495.1	457.1	703.9	696.9	722.8	699.6	724.2	718.3	698.9	512.6	578.6	655.8	7,663.9
7. RSH	235.8	202.8	21.4	4.6	2.0	1.8	0.6	6.6	2.6	1.8	6.0	70.8	556.8
8. UH	13.1	12.1	18.7	18.5	19.2	18.6	19.2	19.1	18.5	229.6	135.4	17.4	539.3
9. POH & PPOH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	216.0	120.0	0.0	336.0
10. FOH & PFOH	13.1	12.1	18.6	18.4	19.1	18.5	19.1	19.0	18.5	13.5	15.3	17.3	202.4
11. MOH & PMOH	1.0	0.9	1.4	1.4	1.5	1.4	1.5	1.5	1.4	1.1	1.2	1.3	15.7
12. Oper. Btu(MBtu)	1,484,584	1,376,774	2,244,733	2,231,648	2,361,648	2,329,356	2,437,059	2,280,410	2,280,981	1,719,630	1,922,530	2,128,354	24,800,941
13. Net Gen. (MWH)	210,455.0	195,258.0	320,234.0	318,510.0	337,806.0	333,892.0	349,759.0	325,167.0	326,230.0	246,707.0	275,512.0	304,211.0	3,543,741.0
14. ANOHR (Btu/KWH)	7,054	7,051	7,010	7,007	6,991	6,976	6,968	7,013	6,992	6,970	6,978	6,996	6,999
15. NOF (%)	81.9	82.3	87.7	88.1	90.0	92.0	93.1	87.2	89.9	92.7	91.7	89.4	89.1
16. NSC (MW)	519	519	519	519	519	519	519	519	519	519	519	519	519
17. ANOHR Equation	ANOHR=	-7.744	x NOF +	7,688.5									

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PLANNED OUTAGE SCHEDULES

Duke Energy Florida
Period of: January 2021 - December 2021

Plant/Unit	Planned Outage Dates	Reason for Outage
Bartow 4	03/06 (0001) - 03/12 (2400)	3x1, Boroscopes A&C, Gen Minor (A&C)
Bartow 4	10/23 (0001) - 11/21 (2400)	3 x 0, L-0 inspection, replace F91 delam valves, boroscopes B&D, CW pipe coating, BOP
Crystal River 5	04/03 (0001) - 04/30 (2400)	BOP, potential cooling tower work
Hines 1	04/14 (0001) - 05/27 (2400)	Full Block, MI (A&B), BOP, repl. Exhaust, ST1 Gen Med. Robotic
Hines 2	11/06 (0001) - 11/19 (2400)	Full Block, BOP, L-0 inspection, ST-Gen Med (8days)
Hines 3	02/13 (0001) - 05/13 (2400)	Full Block, BOP, ST-3 Major (HP, IP/LP), ST-V, CT Rotor EOL & CT Major (A&B), Gen Major (A&B&ST), Exciter major (A&B)
Hines 4	10/23 (0001) - 11/05 (2400)	Full Block, BOP

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AVERAGE NET OPERATING HEAT RATE CURVES

DUKE ENERGY FLORIDA

Bartow Unit 4

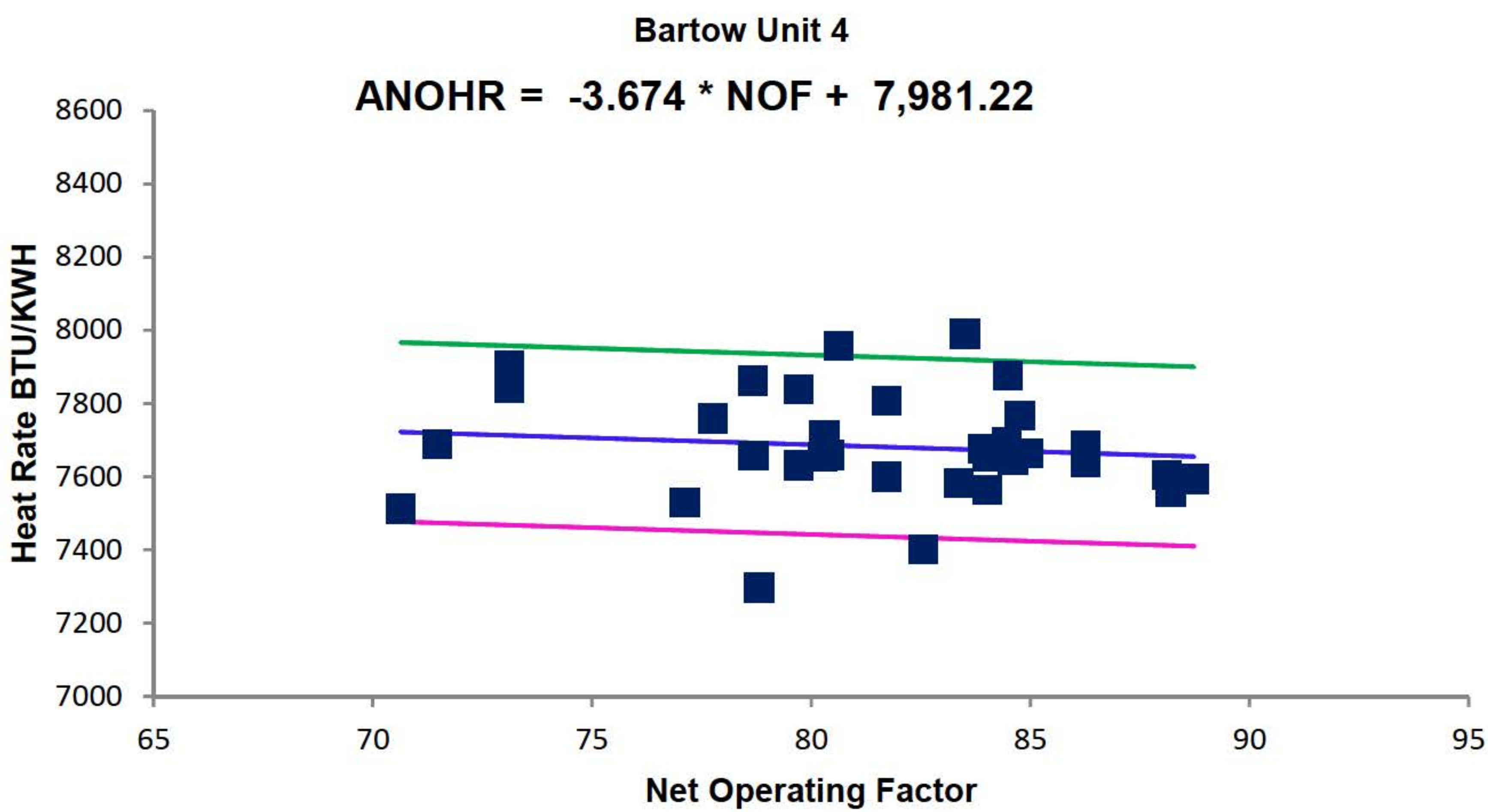
ANOHR = -3.674 * NOF + 7,981.22

TABLE OF RESIDUALS

DATE	OUTPUT FACTOR	ACT MONTHLY HEATRATE	PROJECTED HEATRATE	DIFFERENCE (ACT-PROJ)	HEAT RATE RANGE @90% CONFID
Jul-17	86.3	7,685	7,664	20.9	244.9
Aug-17	88.1	7,604	7,657	-53.4	244.9
Sep-17	84.5	7,877	7,671	206.0	244.9
Oct-17	84.8	7,767	7,670	97.5	244.9
Nov-17	78.7	7,862	7,692	169.6	244.9
Dec-17	83.5	7,990	7,674	315.5	244.9
Jan-18	80.4	7,658	7,686	-27.4	244.9
Feb-18	80.3	7,655	7,686	-31.7	244.9
Mar-18	80.3	7,715	7,686	28.3	244.9
Apr-18	88.7	7,593	7,655	-61.9	244.9
May-18	80.6	7,958	7,685	273.1	244.9
Jun-18	84.0	7,563	7,672	-109.6	244.9
Jul-18	84.5	7,694	7,671	22.7	244.9
Aug-18	83.9	7,677	7,673	4.2	244.9
Sep-18	86.3	7,638	7,664	-26.3	244.9
Oct-18	88.2	7,558	7,657	-99.4	244.9
Nov-18	84.6	7,647	7,670	-23.6	244.9
Dec-18	78.7	7,657	7,692	-34.7	244.9
Jan-19	79.7	7,632	7,688	-56.2	244.9
Feb-19	71.5	7,689	7,719	-29.5	244.9
Apr-19	73.1	7,902	7,713	189.9	244.9
May-19	83.4	7,583	7,675	-91.9	244.9
Jun-19	84.0	7,655	7,672	-17.5	244.9
Jul-19	81.7	7,808	7,681	127.1	244.9
Aug-19	85.0	7,665	7,669	-4.5	244.9
Sep-19	73.1	7,842	7,713	129.2	244.9
Dec-19	81.7	7,600	7,681	-80.6	244.9
Jan-20	78.8	7,296	7,692	-395.4	244.9
Feb-20	77.8	7,759	7,696	63.3	244.9
Mar-20	79.7	7,838	7,688	150.0	244.9
Apr-20	70.6	7,513	7,722	-208.8	244.9
May-20	77.1	7,529	7,698	-169.4	244.9
Jun-20	82.6	7,402	7,678	-275.6	244.9

Regression Output:

Constant	7981.22
Std Err of Y Est	151.1989349
R Squared	0.012982032
No. of Observations	33
Degrees of Freedom	31
X Coefficient	-3.67401753
Std Err of Coef.	5.753757801


Bartow Unit 4
ANOHR = -3.674 * NOF + 7,981.22
Heat Rate BTU/KWH
8600
8400
8200
8000
7800
7600
7400
7200
7000
65
70
75
80
85
90
95
Net Operating Factor

DUKE ENERGY FLORIDA

Crystal River Unit 4

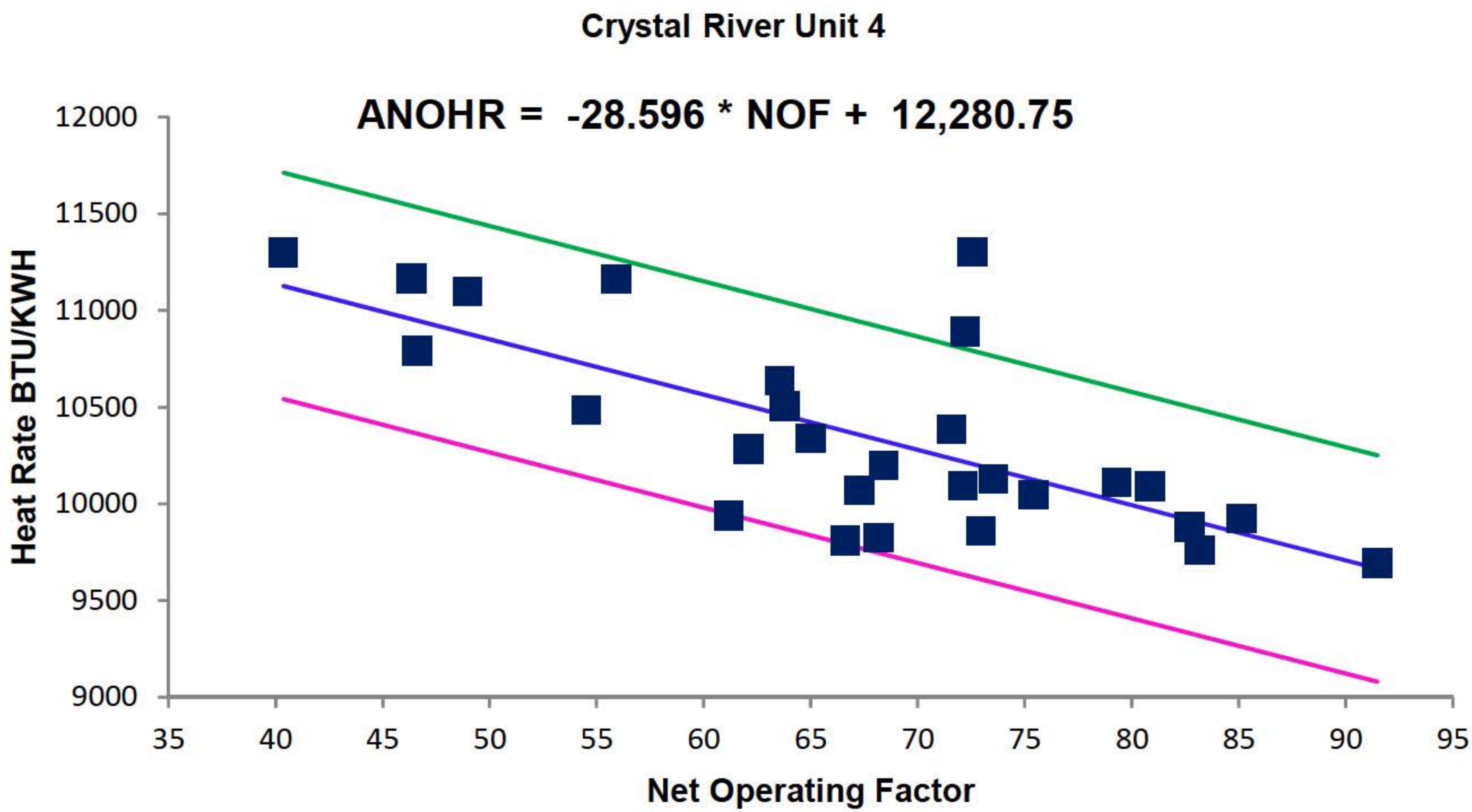
ANOHR = -28.596 * NOF + 12,280.75

TABLE OF RESIDUALS

DATE	OUTPUT FACTOR	ACT MONTHLY HEATRATE	PROJECTED HEATRATE	DIFFERENCE (ACT-PROJ)	HEAT RATE RANGE @90% CONFID
Jul-17	71.6	10,383	10,234	149.0	585.3
Aug-17	75.4	10,047	10,124	-77.6	585.3
Sep-17	72.2	10,890	10,216	673.8	585.3
Oct-17	72.6	11,302	10,206	1095.8	585.3
Dec-17	72.1	10,094	10,218	-124.5	585.3
Feb-18	67.3	10,068	10,357	-288.6	585.3
Mar-18	66.6	9,811	10,376	-565.8	585.3
Apr-18	63.5	10,637	10,464	172.6	585.3
May-18	68.4	10,198	10,325	-126.9	585.3
Jun-18	73.5	10,130	10,178	-48.1	585.3
Jul-18	82.7	9,880	9,916	-36.5	585.3
Aug-18	85.1	9,922	9,847	74.9	585.3
Sep-18	79.3	10,111	10,013	98.0	585.3
Oct-18	83.2	9,762	9,903	-140.6	585.3
Nov-18	80.8	10,090	9,969	121.1	585.3
Dec-18	91.5	9,691	9,665	26.5	585.3
Jan-19	46.4	11,168	10,955	212.3	585.3
Mar-19	61.2	9,939	10,532	-592.2	585.3
Apr-19	62.1	10,283	10,505	-221.6	585.3
May-19	65.0	10,337	10,423	-85.9	585.3
Jun-19	63.8	10,505	10,457	48.4	585.3
Jul-19	54.5	10,485	10,722	-236.7	585.3
Aug-19	55.9	11,162	10,682	480.5	585.3
Sep-19	46.6	10,791	10,948	-157.2	585.3
Oct-19	68.2	9,825	10,332	-506.6	585.3
Nov-19	73.0	9,861	10,194	-333.8	585.3
May-20	40.4	11,299	11,127	172.2	585.3
Jun-20	49.0	11,098	10,881	217.6	585.3

Regression Output:

Constant	12280.75
Std Err of Y Est	362.3176774
R Squared	0.50549982
No. of Observations	28
Degrees of Freedom	26
X Coefficient	-28.59577776
Std Err of Coef.	5.546741973


Crystal River Unit 4
ANOHR = -28.596 * NOF + 12,280.75
Heat Rate BTU/KWH
12000
11500
11000
10500
10000
9500
9000
35
40
45
50
55
60
65
70
75
80
85
90
95
Net Operating Factor

DUKE ENERGY FLORIDA

Crystal River Unit 5

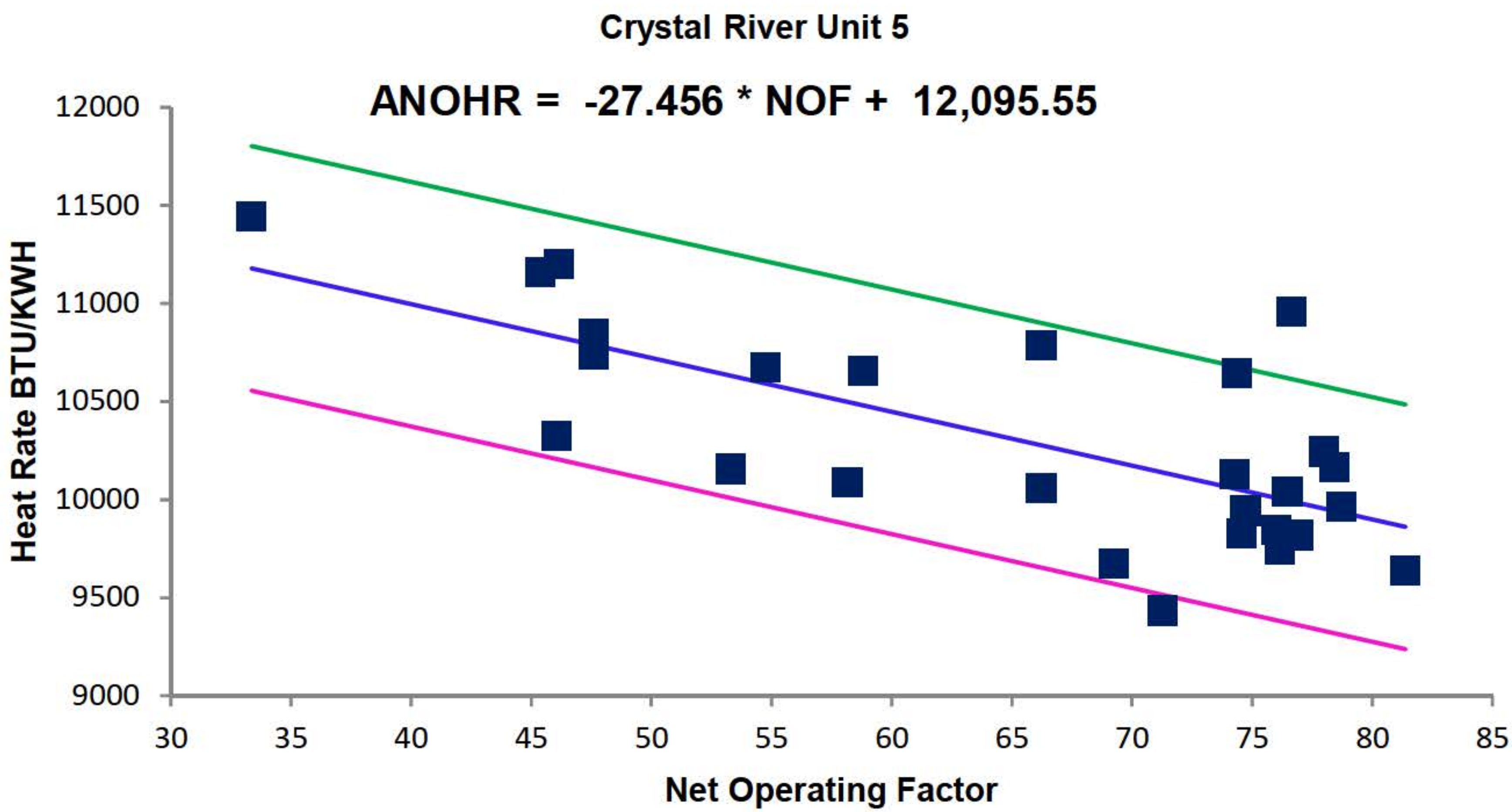
ANOHR = -27.456 * NOF + 12,095.55

TABLE OF RESIDUALS

DATE	OUTPUT FACTOR	ACT MONTHLY HEATRATE	PROJECTED HEATRATE	DIFFERENCE (ACT-PROJ)	HEAT RATE RANGE @90% CONFID
Jul-17	78.7	9,965	9,934	30.9	623.7
Aug-17	76.0	9,848	10,008	-159.8	623.7
Sep-17	74.4	10,648	10,054	593.4	623.7
Oct-17	76.7	10,960	9,991	968.9	623.7
Jan-18	81.4	9,640	9,861	-220.7	623.7
Feb-18	66.2	10,058	10,277	-219.7	623.7
Mar-18	74.6	9,831	10,048	-217.8	623.7
Apr-18	66.2	10,787	10,277	510.0	623.7
May-18	58.8	10,656	10,481	175.8	623.7
Jun-18	74.3	10,128	10,056	71.6	623.7
Jul-18	78.0	10,246	9,954	292.0	623.7
Aug-18	77.0	9,820	9,983	-162.3	623.7
Sep-18	76.5	10,040	9,996	44.5	623.7
Oct-18	74.7	9,944	10,044	-100.2	623.7
Nov-18	78.4	10,164	9,942	221.6	623.7
Dec-18	76.2	9,749	10,005	-255.4	623.7
Jan-19	47.6	10,845	10,789	55.9	623.7
Jun-19	46.1	11,203	10,829	374.8	623.7
Jul-19	53.3	10,155	10,632	-477.2	623.7
Aug-19	54.8	10,677	10,592	85.0	623.7
Sep-19	58.2	10,086	10,499	-413.1	623.7
Oct-19	69.3	9,675	10,194	-518.7	623.7
Nov-19	71.3	9,435	10,138	-703.0	623.7
Mar-20	33.4	11,447	11,180	267.4	623.7
Apr-20	46.1	10,327	10,831	-504.5	623.7
May-20	47.6	10,742	10,789	-47.7	623.7
Jun-20	45.4	11,158	10,850	308.3	623.7

Regression Output:

Constant	12095.55
Std Err of Y Est	386.3474897
R Squared	0.498313744
No. of Observations	27
Degrees of Freedom	25
X Coefficient	-27.45646286
Std Err of Coef.	5.509843359


Crystal River Unit 5
ANOHR = -27.456 * NOF + 12,095.55
Heat Rate BTU/KWH
12000
11500
11000
10500
10000
9500
9000
30
35
40
45
50
55
60
65
70
75
80
85
Net Operating Factor

DUKE ENERGY FLORIDA

Hines Unit 1

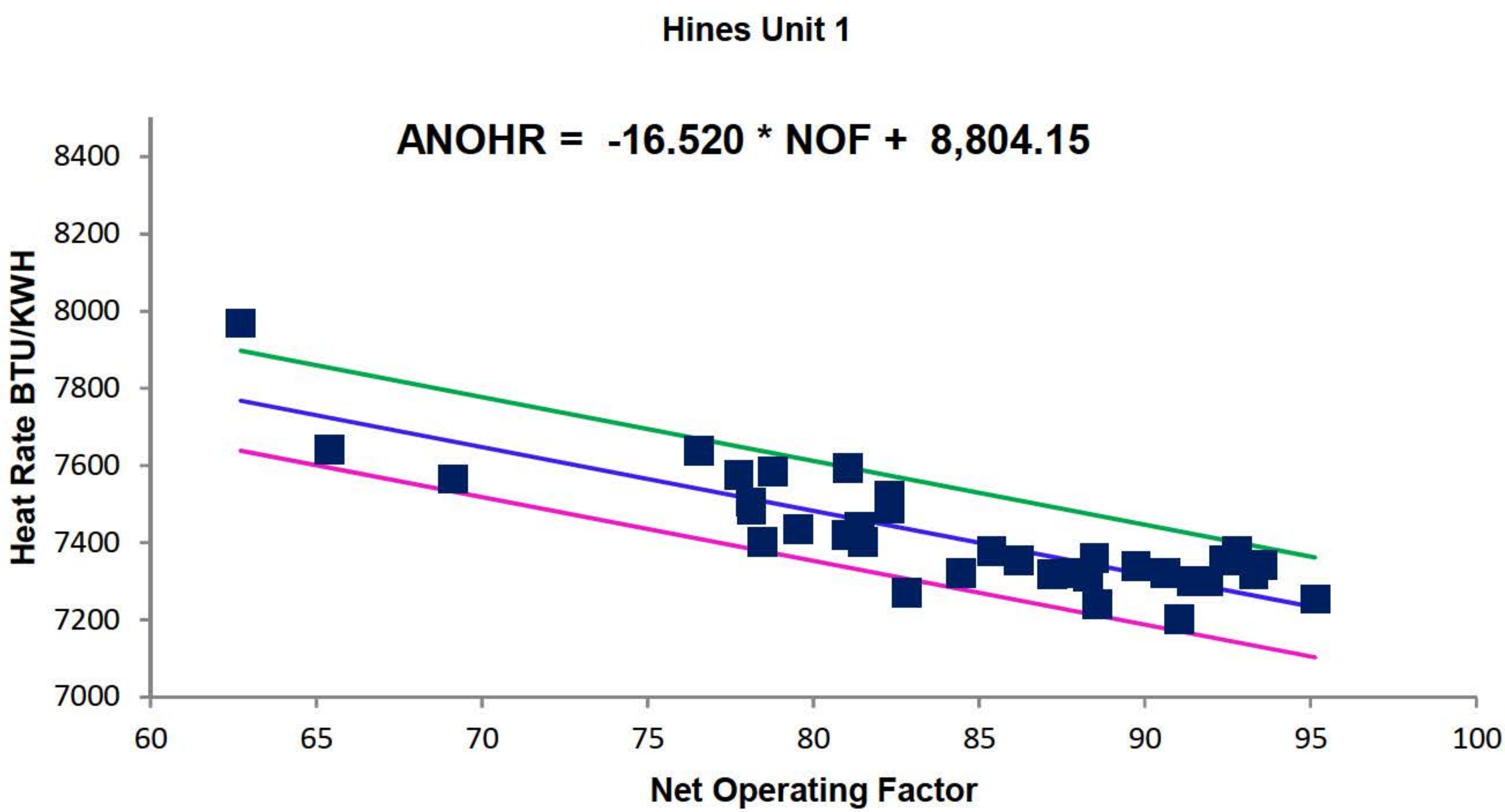
ANOHR = -16.520 * NOF + 8,804.15

TABLE OF RESIDUALS

DATE	OUTPUT FACTOR	ACT MONTHLY HEATRATE	PROJECTED HEATRATE	DIFFERENCE (ACT-PROJ)	HEAT RATE RANGE @90% CONFID
Jul-17	85.4	7,377	7,394	-16.8	129.5
Aug-17	88.3	7,310	7,345	-35.3	129.5
Sep-17	88.6	7,240	7,341	-100.9	129.5
Oct-17	89.7	7,338	7,322	16.3	129.5
Dec-17	78.5	7,403	7,508	-105.2	129.5
Jan-18	91.0	7,201	7,300	-99.5	129.5
Feb-18	91.4	7,301	7,294	6.6	129.5
Mar-18	92.4	7,354	7,278	75.9	129.5
Apr-18	91.9	7,300	7,286	14.4	129.5
May-18	87.8	7,323	7,354	-30.9	129.5
Jun-18	92.8	7,379	7,271	107.4	129.5
Jul-18	93.6	7,343	7,259	84.0	129.5
Aug-18	90.6	7,321	7,307	13.5	129.5
Sep-18	93.3	7,319	7,263	56.1	129.5
Oct-18	87.2	7,318	7,364	-45.6	129.5
Nov-18	82.8	7,270	7,436	-166.4	129.5
Dec-18	62.7	7,969	7,768	200.3	129.5
Jan-19	65.4	7,642	7,724	-81.5	129.5
Feb-19	81.5	7,401	7,458	-56.3	129.5
Mar-19	79.6	7,437	7,490	-53.3	129.5
Apr-19	69.1	7,566	7,662	-96.4	129.5
May-19	82.3	7,489	7,445	44.0	129.5
Jun-19	81.0	7,420	7,466	-45.7	129.5
Jul-19	82.3	7,520	7,445	75.7	129.5
Aug-19	86.2	7,355	7,380	-25.5	129.5
Sep-19	81.4	7,442	7,460	-17.4	129.5
Oct-19	88.5	7,361	7,342	18.6	129.5
Nov-19	95.1	7,254	7,232	21.4	129.5
Dec-19	84.4	7,321	7,409	-88.5	129.5
Jan-20	81.0	7,594	7,466	128.4	129.5
Feb-20	76.6	7,640	7,540	100.5	129.5
Mar-20	78.1	7,506	7,514	-7.7	129.5
Apr-20	78.1	7,485	7,513	-28.3	129.5
May-20	77.7	7,576	7,520	56.1	129.5
Jun-20	78.8	7,585	7,503	82.0	129.5

Regression Output:

Constant	8804.15
Std Err of Y Est	79.84423844
R Squared	0.729897341
No. of Observations	35
Degrees of Freedom	33
X Coefficient	-16.51989691
Std Err of Coef.	1.749378975


Hines Unit 1
ANOHR = -16.520 * NOF + 8,804.15
Heat Rate BTU/KWH
8400
8200
8000
7800
7600
7400
7200
7000
60
65
70
75
80
85
90
95
100
Net Operating Factor

DUKE ENERGY FLORIDA

Hines Unit 2

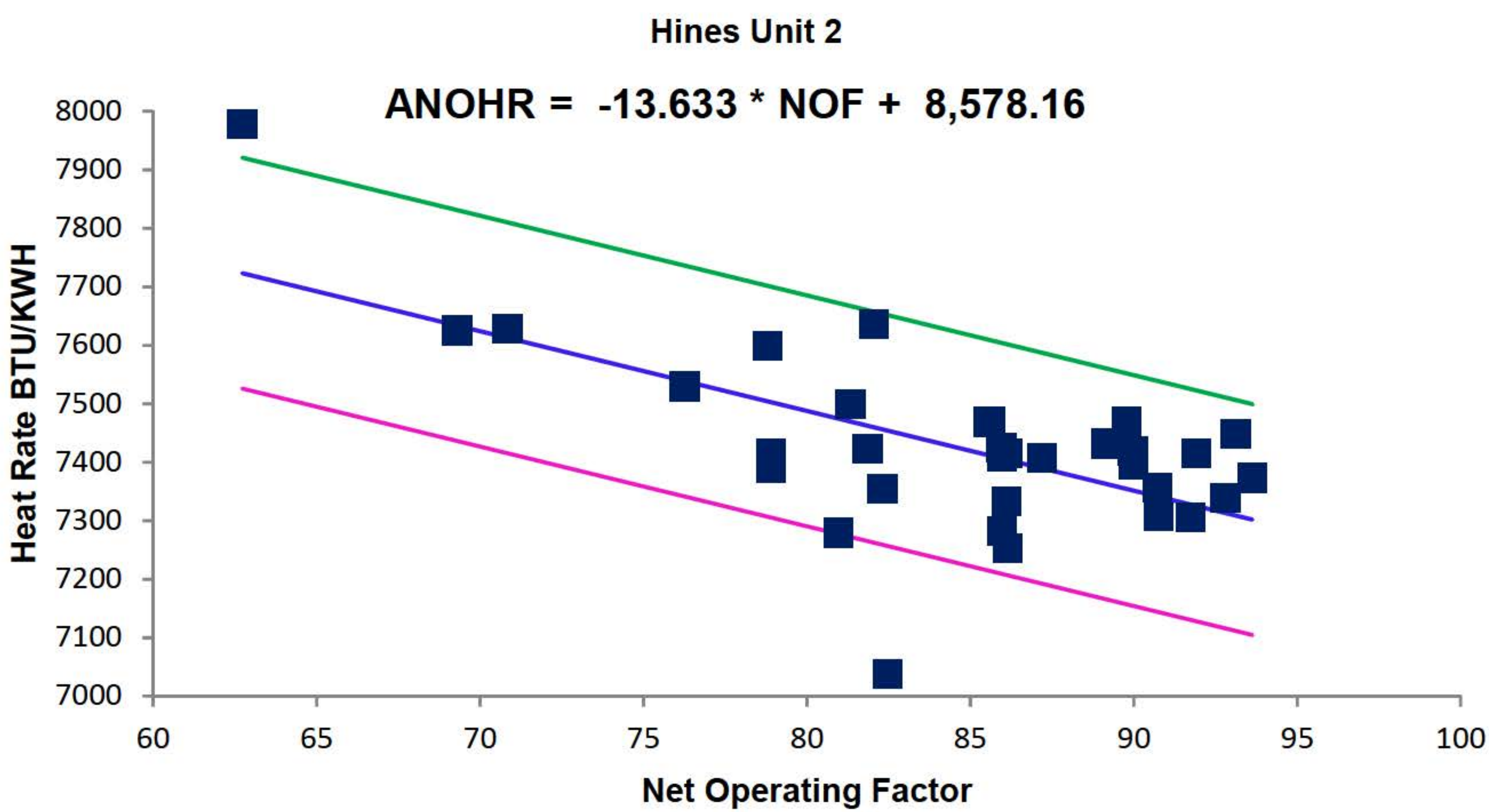
ANOHR = -13.633 * NOF + 8,578.16

TABLE OF RESIDUALS

DATE	OUTPUT FACTOR	ACT MONTHLY HEATRATE	PROJECTED HEATRATE	DIFFERENCE (ACT-PROJ)	HEAT RATE RANGE @90% CONFID
Jul-17	87.2	7,407	7,389	17.6	197.4
Aug-17	86.0	7,283	7,406	-123.2	197.4
Sep-17	82.1	7,636	7,459	176.4	197.4
Oct-17	62.7	7,978	7,723	255.5	197.4
Dec-17	86.1	7,332	7,404	-72.3	197.4
Jan-18	86.2	7,253	7,404	-151.1	197.4
Feb-18	82.5	7,038	7,454	-415.7	197.4
Mar-18	91.7	7,306	7,328	-22.0	197.4
Apr-18	90.0	7,396	7,351	44.8	197.4
May-18	86.0	7,410	7,406	3.5	197.4
Jun-18	89.8	7,470	7,354	115.9	197.4
Jul-18	93.1	7,447	7,309	138.8	197.4
Aug-18	92.8	7,339	7,313	25.9	197.4
Sep-18	91.9	7,414	7,325	88.8	197.4
Oct-18	90.8	7,307	7,341	-33.5	197.4
Nov-18	78.9	7,415	7,503	-87.5	197.4
Dec-18	76.3	7,529	7,539	-9.0	197.4
Jan-19	81.0	7,279	7,474	-195.5	197.4
Feb-19	82.3	7,354	7,456	-101.9	197.4
Apr-19	90.7	7,356	7,341	14.4	197.4
May-19	89.2	7,432	7,363	68.8	197.4
Jun-19	86.0	7,425	7,406	18.3	197.4
Jul-19	85.6	7,468	7,412	56.5	197.4
Aug-19	85.6	7,470	7,411	59.1	197.4
Sep-19	81.3	7,498	7,469	29.0	197.4
Oct-19	90.0	7,419	7,352	67.8	197.4
Nov-19	93.6	7,373	7,302	71.0	197.4
Dec-19	81.9	7,422	7,462	-39.9	197.4
Jan-20	78.9	7,390	7,503	-112.6	197.4
Feb-20	86.2	7,414	7,404	10.4	197.4
Apr-20	69.3	7,625	7,633	-8.5	197.4
May-20	70.8	7,628	7,612	15.6	197.4
Jun-20	78.8	7,599	7,504	94.7	197.4

Regression Output:

Constant	8578.16
Std Err of Y Est	121.830277
R Squared	0.399107581
No. of Observations	33
Degrees of Freedom	31
X Coefficient	-13.63304066
Std Err of Coef.	3.004451911


Hines Unit 2
ANOHR = -13.633 * NOF + 8,578.16
Heat Rate BTU/KWH
8000
7900
7800
7700
7600
7500
7400
7300
7200
7100
7000
60
65
70
75
80
85
90
95
100
Net Operating Factor

DUKE ENERGY FLORIDA

Hines Unit 3

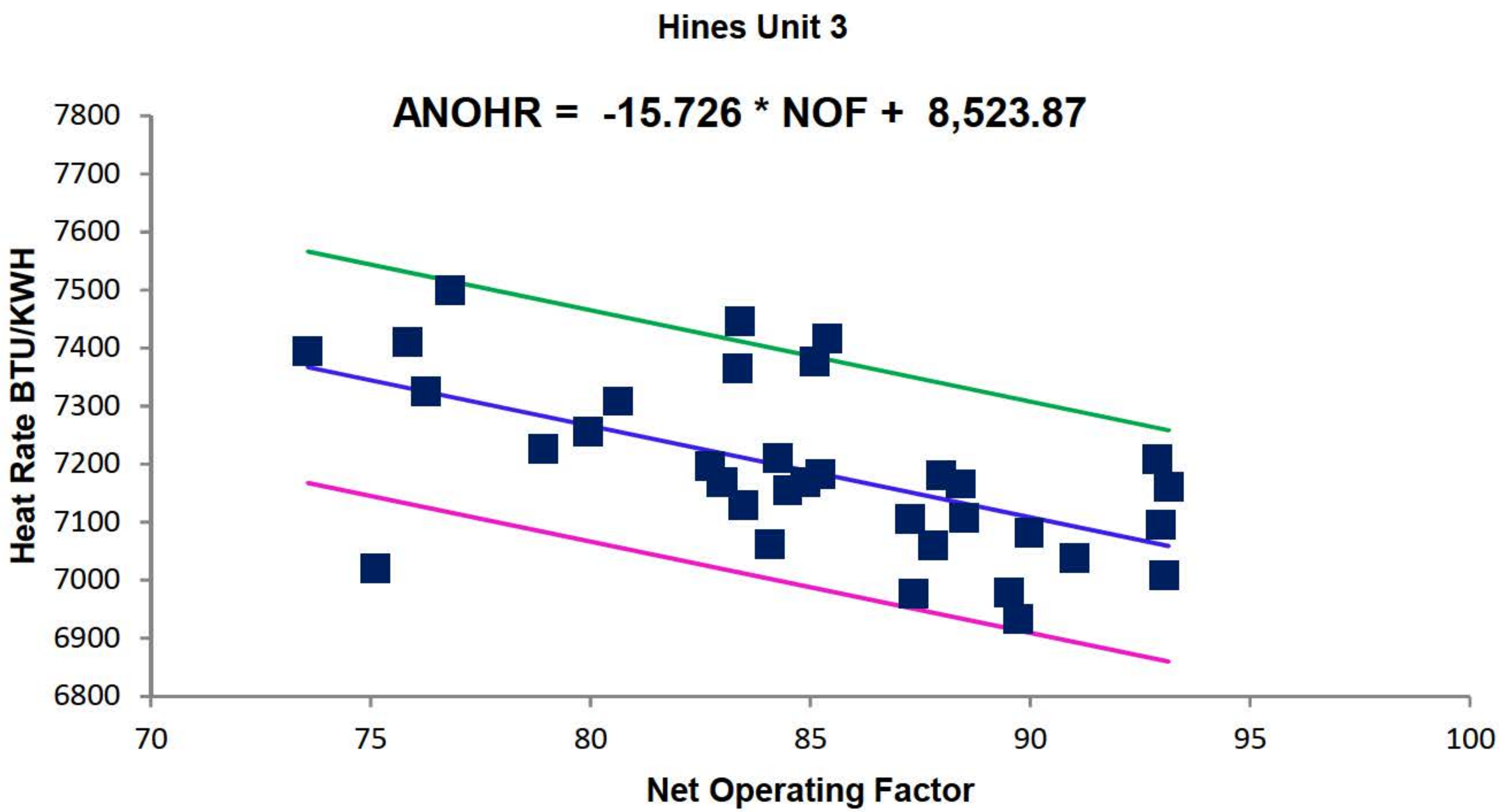
ANOHR = -15.726 * NOF + 8,523.87

TABLE OF RESIDUALS

DATE	OUTPUT FACTOR	ACT MONTHLY HEATRATE	PROJECTED HEATRATE	DIFFERENCE (ACT-PROJ)	HEAT RATE RANGE @90% CONFID
Jul-17	87.3	7,106	7,151	-45.9	199.2
Aug-17	90.0	7,082	7,109	-26.6	199.2
Sep-17	75.1	7,020	7,343	-322.2	199.2
Oct-17	89.7	6,934	7,113	-179.0	199.2
Dec-17	87.3	6,978	7,150	-172.4	199.2
Jan-18	83.4	7,447	7,212	234.5	199.2
Feb-18	83.3	7,365	7,213	152.2	199.2
Mar-18	87.8	7,060	7,143	-83.0	199.2
Apr-18	88.4	7,166	7,134	32.0	199.2
May-18	88.5	7,107	7,132	-25.4	199.2
Jun-18	91.0	7,038	7,093	-54.3	199.2
Jul-18	93.0	7,009	7,061	-52.1	199.2
Aug-18	92.9	7,209	7,063	145.7	199.2
Sep-18	93.2	7,161	7,059	101.5	199.2
Nov-18	85.2	7,182	7,183	-1.6	199.2
Dec-18	85.1	7,376	7,186	190.1	199.2
Jan-19	85.4	7,416	7,181	235.0	199.2
Feb-19	76.3	7,325	7,325	0.7	199.2
Mar-19	83.0	7,169	7,219	-50.2	199.2
Apr-19	84.1	7,063	7,202	-138.9	199.2
May-19	88.0	7,180	7,141	39.5	199.2
Jun-19	84.3	7,211	7,199	11.6	199.2
Jul-19	84.5	7,155	7,195	-40.4	199.2
Aug-19	84.9	7,170	7,189	-19.3	199.2
Sep-19	80.6	7,309	7,256	52.5	199.2
Oct-19	93.0	7,096	7,062	34.6	199.2
Nov-19	89.5	6,979	7,116	-137.1	199.2
Dec-19	75.9	7,411	7,331	79.6	199.2
Jan-20	76.8	7,500	7,316	184.0	199.2
Feb-20	82.7	7,197	7,223	-25.6	199.2
Mar-20	80.0	7,256	7,267	-10.4	199.2
Apr-20	78.9	7,228	7,283	-55.0	199.2
May-20	73.6	7,395	7,367	27.6	199.2
Jun-20	83.5	7,129	7,211	-81.8	199.2

Regression Output:

Constant	8523.87
Std Err of Y Est	122.9033713
R Squared	0.330979873
No. of Observations	34
Degrees of Freedom	32
X Coefficient	-15.72599201
Std Err of Coef.	3.952408826


Hines Unit 3
ANOHR = -15.726 * NOF + 8,523.87
Heat Rate BTU/KWH
7800
7700
7600
7500
7400
7300
7200
7100
7000
6900
6800
70
75
80
85
90
95
100
Net Operating Factor

DUKE ENERGY FLORIDA

Hines Unit 4

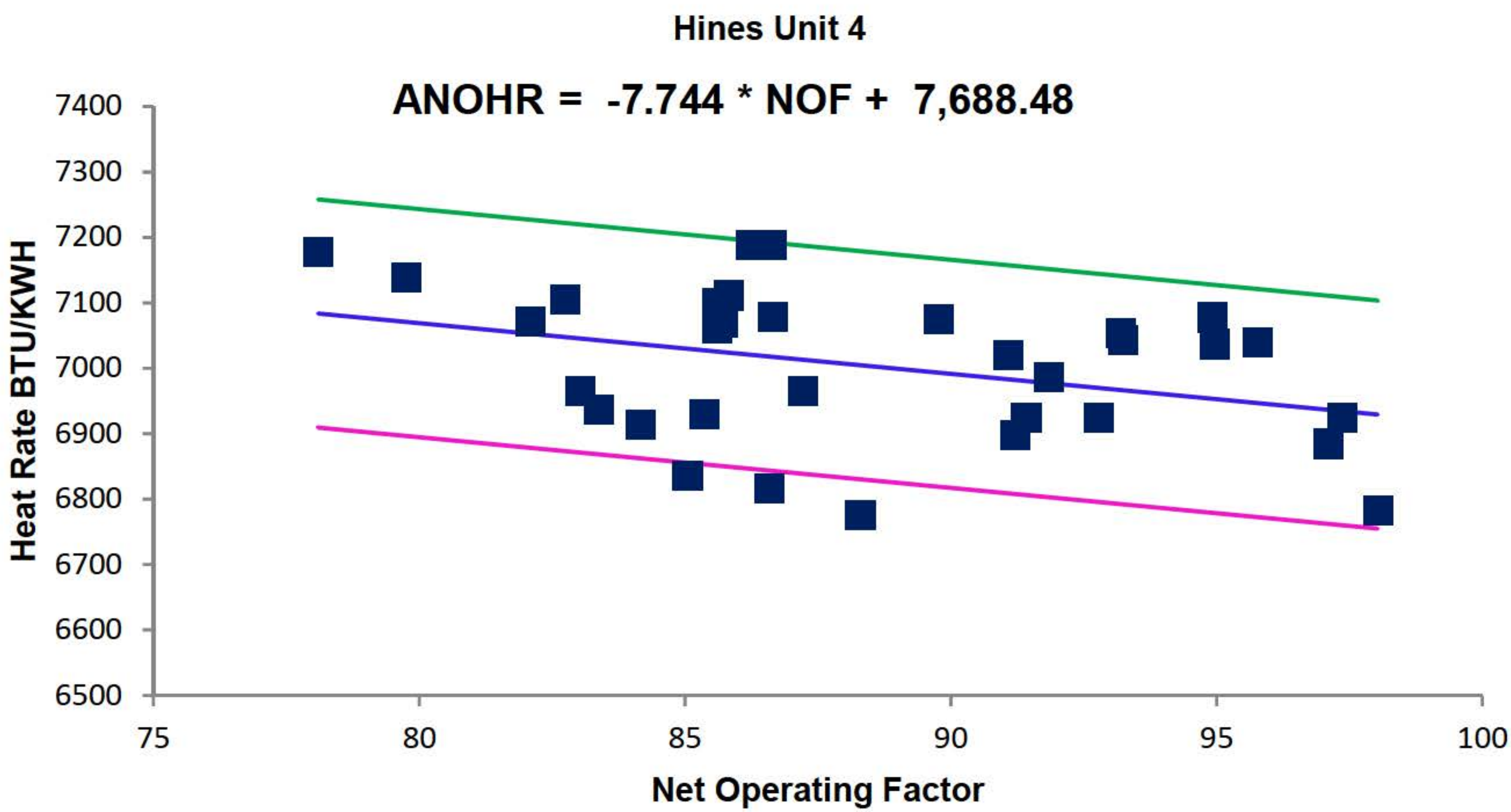
ANOHR = -7.744 * NOF + 7,688.48

TABLE OF RESIDUALS

DATE	OUTPUT FACTOR	ACT MONTHLY HEATRATE	PROJECTED HEATRATE	DIFFERENCE (ACT-PROJ)	HEAT RATE RANGE @90% CONFID
Jul-17	82.8	7,105	7,048	57.2	174.2
Aug-17	86.7	7,079	7,017	62.0	174.2
Sep-17	91.9	6,986	6,977	9.3	174.2
Oct-17	94.9	7,077	6,953	123.9	174.2
Dec-17	87.2	6,964	7,013	-48.6	174.2
Jan-18	92.8	6,925	6,970	-45.2	174.2
Feb-18	91.2	6,898	6,982	-83.7	174.2
Mar-18	98.0	6,783	6,929	-146.0	174.2
Apr-18	91.1	7,021	6,983	37.9	174.2
May-18	93.2	7,053	6,967	86.8	174.2
Jun-18	95.0	7,037	6,953	84.1	174.2
Jul-18	95.8	7,040	6,947	93.3	174.2
Aug-18	93.2	7,044	6,966	77.7	174.2
Sep-18	97.4	6,924	6,935	-10.6	174.2
Oct-18	97.1	6,885	6,936	-51.7	174.2
Dec-18	85.1	6,836	7,030	-193.9	174.2
Jan-19	91.4	6,925	6,981	-55.5	174.2
Feb-19	84.2	6,913	7,037	-123.6	174.2
Mar-19	83.4	6,937	7,043	-105.7	174.2
Apr-19	86.6	6,817	7,018	-201.0	174.2
May-19	89.8	7,075	6,993	81.4	174.2
Jun-19	85.6	7,061	7,025	35.1	174.2
Jul-19	86.2	7,188	7,021	167.2	174.2
Aug-19	86.6	7,187	7,018	169.9	174.2
Sep-19	85.7	7,069	7,025	44.5	174.2
Oct-19	85.6	7,100	7,025	74.1	174.2
Dec-19	88.3	6,776	7,005	-229.2	174.2
Jan-20	85.4	6,930	7,027	-97.1	174.2
Feb-20	83.0	6,965	7,045	-80.1	174.2
Mar-20	78.1	7,178	7,084	94.2	174.2
Apr-20	79.8	7,138	7,071	67.5	174.2
May-20	82.1	7,070	7,053	17.8	174.2
Jun-20	85.8	7,112	7,024	87.9	174.2

Regression Output:

Constant	7688.48
Std Err of Y Est	107.523129
R Squared	0.128639767
No. of Observations	33
Degrees of Freedom	31
X Coefficient	-7.744256015
Std Err of Coef.	3.620012751


Hines Unit 4
ANOHR = -7.744 * NOF + 7,688.48
Heat Rate BTU/KWH
7400
7300
7200
7100
7000
6900
6800
6700
6600
6500
75
80
85
90
95
100
Net Operating Factor

UNPLANNED OUTAGE RATE TABLES AND GRAPHS

Bartow

Unit 4

	Jul-17	Aug-17	Sep-17	Oct-17	Nov-17	Dec-17	Jan-18	Feb-18	Mar-18	Apr-18	May-18	Jun-18	Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18
PER HOURS	744.00	744.00	720.00	744.00	721.00	744.00	744.00	672.00	743.00	720.00	744.00	720.00	744.00	744.00	720.00	744.00	721.00	744.00
SER HOURS	716.07	744.00	673.72	703.50	620.52	669.22	723.12	576.01	617.32	699.21	660.66	586.42	601.19	675.79	702.70	708.62	654.33	605.85
RSH	4.35	0.00	30.57	24.71	42.01	0.00	20.88	95.74	13.25	14.12	15.97	7.14	7.57	5.18	0.51	35.38	23.94	55.22
UH	23.58	0.00	15.71	15.79	58.47	74.78	0.00	0.25	112.43	6.67	67.37	126.44	135.24	63.03	16.79	0.00	42.73	82.93
POH	0.00	0.00	0.00	0.00	53.82	30.75	0.00	0.00	111.65	0.00	0.00	0.00	0.00	0.00	0.00	0.00	27.77	23.38
FOH	23.58	0.00	7.01	0.67	3.68	0.00	0.00	0.25	0.78	6.67	67.37	126.44	135.24	63.03	6.61	0.00	3.35	41.02
MOH	0.00	0.00	8.70	15.12	0.97	44.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	10.18	0.00	11.61	18.53
PFOH	313.68	288.85	279.53	315.66	279.92	288.85	0.00	15.09	0.00	0.00	0.00	229.23	247.90	139.46	19.28	0.00	6.06	75.65
LRPF	78.98	84.00	81.39	82.28	84.00	71.19	0.00	120.02	0.00	0.00	0.00	40.82	46.36	47.15	66.99	0.00	67.04	67.00
EFOH	22.42	21.96	20.59	23.50	21.28	18.61	0.00	1.68	0.00	0.00	0.00	8.66	10.64	6.09	1.20	0.00	0.38	4.69
PMOH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	21.27	0.00
LRPM	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	67.00	0.00
EMOH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.32	0.00
NPC	1105.00	1105.00	1105.00	1105.00	1105.00	1105.00	1080.00	1080.00	1080.00	1080.00	1080.00	1080.00	1080.00	1080.00	1080.00	1080.00	1080.00	1080.00

MONTHLY	Jul-17	Aug-17	Sep-17	Oct-17	Nov-17	Dec-17	Jan-18	Feb-18	Mar-18	Apr-18	May-18	Jun-18	Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18
FOR	3.19	0.00	1.03	0.10	0.59	0.00	0.00	0.04	0.13	0.94	9.25	17.74	18.36	8.53	0.93	0.00	0.51	6.34
MOR	0.00	0.00	1.27	2.10	0.16	6.17	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.43	0.00	1.74	2.97
PFOR	3.13	2.95	3.06	3.34	3.43	2.78	0.00	0.29	0.00	0.00	0.00	1.48	1.77	0.90	0.17	0.00	0.06	0.77
PMOR	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.20	0.00
EUOR	6.22	2.95	5.26	5.46	4.15	8.78	0.00	0.33	0.13	0.94	9.25	18.95	19.81	9.36	2.50	0.00	2.49	9.65
EUOF	6.18	2.95	5.04	5.28	3.60	8.42	0.00	0.29	0.10	0.93	9.06	18.76	19.61	9.29	2.50	0.00	2.31	8.63
POF	0.00	0.00	0.00	0.00	7.46	4.13	0.00	0.00	15.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	3.85	3.14
EAF	93.82	97.05	94.96	94.72	88.94	87.45	100.00	99.71	84.87	99.07	90.94	81.24	80.39	90.71	97.50	100.00	93.84	88.22

12 MONTHS	Jul-17	Aug-17	Sep-17	Oct-17	Nov-17	Dec-17	Jan-18	Feb-18	Mar-18	Apr-18	May-18	Jun-18	Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18
FOR	13.42	13.34	13.25	11.83	8.52	7.82	7.77	5.03	1.52	0.68	1.40	2.87	4.23	5.00	4.98	4.97	4.95	5.46
MOR	1.64	1.64	1.76	0.84	0.83	1.39	1.38	1.01	0.95	0.94	0.84	0.85	0.87	0.87	0.89	0.70	0.83	0.51
PFOR	1.50	1.70	1.95	2.19	2.42	2.65	2.64	2.60	2.52	2.32	1.88	1.74	1.61	1.42	1.17	0.87	0.60	0.43
PMOR	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.02	0.02
EUOR	15.95	16.03	16.25	14.41	11.42	11.43	11.37	8.40	4.91	3.90	4.05	5.35	6.56	7.13	6.89	6.42	6.28	6.33
EUOF	15.56	15.64	15.79	14.00	10.97	10.97	10.97	8.02	4.66	3.69	3.84	5.07	6.21	6.75	6.54	6.09	5.98	6.00
POF	0.47	0.47	0.47	0.47	1.08	1.43	1.43	1.43	2.24	2.24	2.24	2.24	2.24	2.24	2.24	2.24	1.94	1.86
EAF	83.97	83.89	83.74	85.53	87.95	87.59	87.59	90.55	93.10	94.07	93.92	92.69	91.55	91.01	91.22	91.67	92.07	92.14

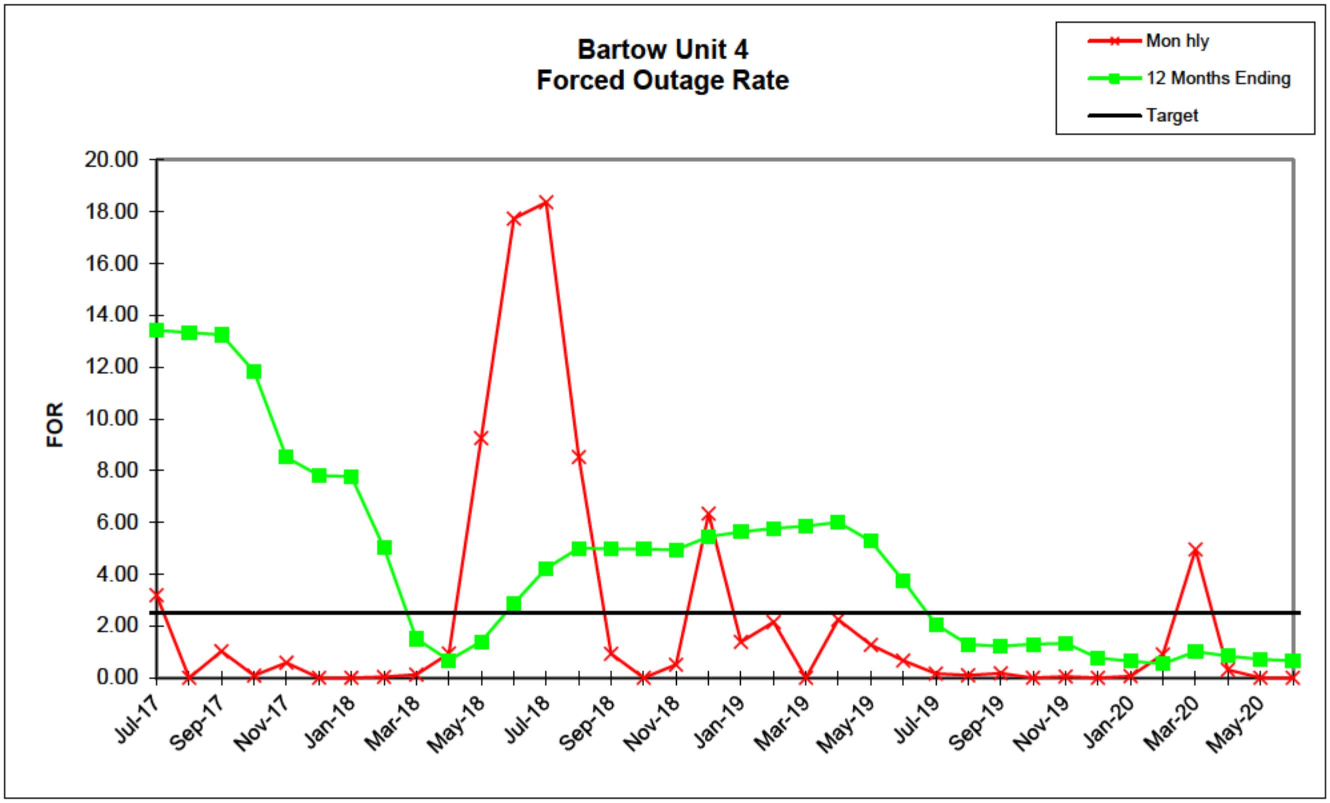
Bartow

Unit 4

	Jan-19	Feb-19	Mar-19	Apr-19	May-19	Jun-19	Jul-19	Aug-19	Sep-19	Oct-19	Nov-19	Dec-19	Jan-20	Feb-20	Mar-20	Apr-20	May-20	Jun-20
PER HOURS	744.00	672.00	743.00	720.00	744.00	720.00	744.00	744.00	720.00	744.00	721.00	744.00	744.00	696.00	743.00	720.00	744.00	720.00
SER HOURS	603.93	593.93	485.47	612.30	711.99	695.10	737.09	740.57	670.41	278.80	189.58	483.51	615.84	621.13	660.96	549.05	654.16	691.89
RSH	129.04	65.02	8.72	1.31	12.29	20.24	4.23	1.78	23.79	7.57	48.81	71.93	8.61	68.95	43.16	137.94	78.46	28.11
UH	11.03	13.05	248.81	106.39	19.72	4.66	2.68	1.65	25.80	457.63	482.61	188.56	119.55	5.92	38.88	33.01	11.38	0.00
POH	0.00	0.00	234.02	70.58	0.00	0.00	0.00	0.00	24.63	457.63	482.51	169.16	119.17	0.00	0.00	0.00	0.00	0.00
FOH	8.52	13.05	0.00	14.09	9.17	4.66	1.22	0.73	1.17	0.00	0.10	0.00	0.38	5.67	34.52	1.74	0.03	0.00
MOH	2.51	0.00	14.79	21.72	10.55	0.00	1.46	0.92	0.00	0.00	0.00	19.40	0.00	0.25	4.36	31.27	11.35	0.00
PFOH	0.00	21.61	0.00	0.00	15.36	24.79	1.93	1.19	1.84	0.00	0.00	0.00	0.00	11.24	11.37	0.00	0.06	0.00
LRPF	0.00	66.98	0.00	0.00	186.98	67.00	186.77	187.05	187.58	0.00	0.00	0.00	0.00	108.20	108.23	0.00	105.50	0.00
EFOH	0.00	1.34	0.00	0.00	2.66	1.54	0.33	0.21	0.32	0.00	0.00	0.00	0.00	1.06	1.08	0.00	0.01	0.00
PMOH	0.00	0.00	182.68	0.00	17.83	0.00	2.32	1.53	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	21.67	0.00
LRPM	0.00	0.00	187.00	0.00	187.01	0.00	187.23	187.30	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	114.17	0.00
EMOH	0.00	0.00	31.63	0.00	3.09	0.00	0.40	0.27	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	2.16	0.00
NPC	1080.00	1080.00	1080.00	1080.00	1080.00	1080.00	1080.00	1080.00	1080.00	1080.00	1080.00	1080.00	1144.00	1144.00	1144.00	1144.00	1144.00	1144.00

MONTHLY	**Jan-19**	**Feb-19**	**Mar-19**	**Apr-19**	**May-19**	**Jun-19**	**Jul-19**	**Aug-19**	**Sep-19**	**Oct-19**	**Nov-19**	**Dec-19**	**Jan-20**	**Feb-20**	**Mar-20**	**Apr-20**	**May-20**	**Jun-20**
FOR	1.39	2.15	0.00	2.25	1.27	0.67	0.17	0.10	0.17	0.00	0.05	0.00	0.06	0.90	4.96	0.32	0.00	0.00
MOR	0.41	0.00	2.96	3.43	1.46	0.00	0.20	0.12	0.00	0.00	0.00	3.86	0.00	0.04	0.66	5.39	1.71	0.00
PFOR	0.00	0.23	0.00	0.00	0.37	0.22	0.05	0.03	0.05	0.00	0.00	0.00	0.00	0.17	0.16	0.00	0.00	0.00
PMOR	0.00	0.00	6.52	0.00	0.43	0.00	0.05	0.04	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.33	0.00
EUOR	1.79	2.37	9.28	5.53	3.48	0.89	0.46	0.29	0.22	0.00	0.05	3.86	0.06	1.11	5.71	5.67	2.04	0.00
EUOF	1.48	2.14	6.25	4.97	3.42	0.86	0.46	0.29	0.21	0.00	0.01	2.61	0.05	1.00	5.38	4.58	1.82	0.00
POF	0.00	0.00	31.50	9.80	0.00	0.00	0.00	0.00	3.42	61.51	66.92	22.74	16.02	0.00	0.00	0.00	0.00	0.00
EAF	98.52	97.86	62.26	85.22	96.58	99.14	99.54	99.71	96.37	38.49	33.06	74.66	83.93	99.00	94.62	95.42	98.18	100.00

12 MONTHS	**Jan-19**	**Feb-19**	**Mar-19**	**Apr-19**	**May-19**	**Jun-19**	**Jul-19**	**Aug-19**	**Sep-19**	**Oct-19**	**Nov-19**	**Dec-19**	**Jan-20**	**Feb-20**	**Mar-20**	**Apr-20**	**May-20**	**Jun-20**
FOR	5.63	5.77	5.86	6.01	5.28	3.76	2.07	1.29	1.23	1.30	1.34	0.77	0.65	0.54	1.01	0.85	0.72	0.66
MOR	0.55	0.55	0.75	1.05	1.18	1.16	1.16	1.16	1.04	1.10	1.01	1.04	1.00	1.00	0.83	0.97	0.99	0.99
PFOR	0.43	0.43	0.44	0.44	0.47	0.37	0.23	0.16	0.15	0.16	0.16	0.09	0.09	0.09	0.10	0.10	0.07	0.04
PMOR	0.02	0.02	0.43	0.44	0.48	0.47	0.47	0.47	0.47	0.50	0.51	0.52	0.52	0.52	0.05	0.05	0.04	0.04
EUOR	6.55	6.68	7.34	7.75	7.23	5.64	3.86	3.03	2.84	3.00	2.97	2.39	2.24	2.13	1.98	1.96	1.80	1.72
EUOF	6.13	6.27	6.79	7.12	6.65	5.17	3.55	2.78	2.59	2.59	2.41	1.89	1.77	1.68	1.61	1.58	1.44	1.37
POF	1.86	1.86	3.26	4.06	4.06	4.06	4.06	4.06	4.34	9.57	14.76	16.42	17.78	17.73	15.07	14.27	14.27	14.27
EAF	92.01	91.87	89.95	88.82	89.29	90.77	92.39	93.16	93.06	87.84	82.84	81.69	80.45	80.58	83.32	84.16	84.29	84.36


Bartow Unit 4
Forced Outage Rate
Mon hly
12 Months Ending
Target
FOR
20.00
18.00
16.00
14.00
12.00
10.00
8.00
6.00
4.00
2.00
0.00
Jul-17
Sep-17
Nov-17
Jan-18
Mar-18
May-18
Jul-18
Sep-18
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Mar-19
May-19
Jul-19
Sep-19
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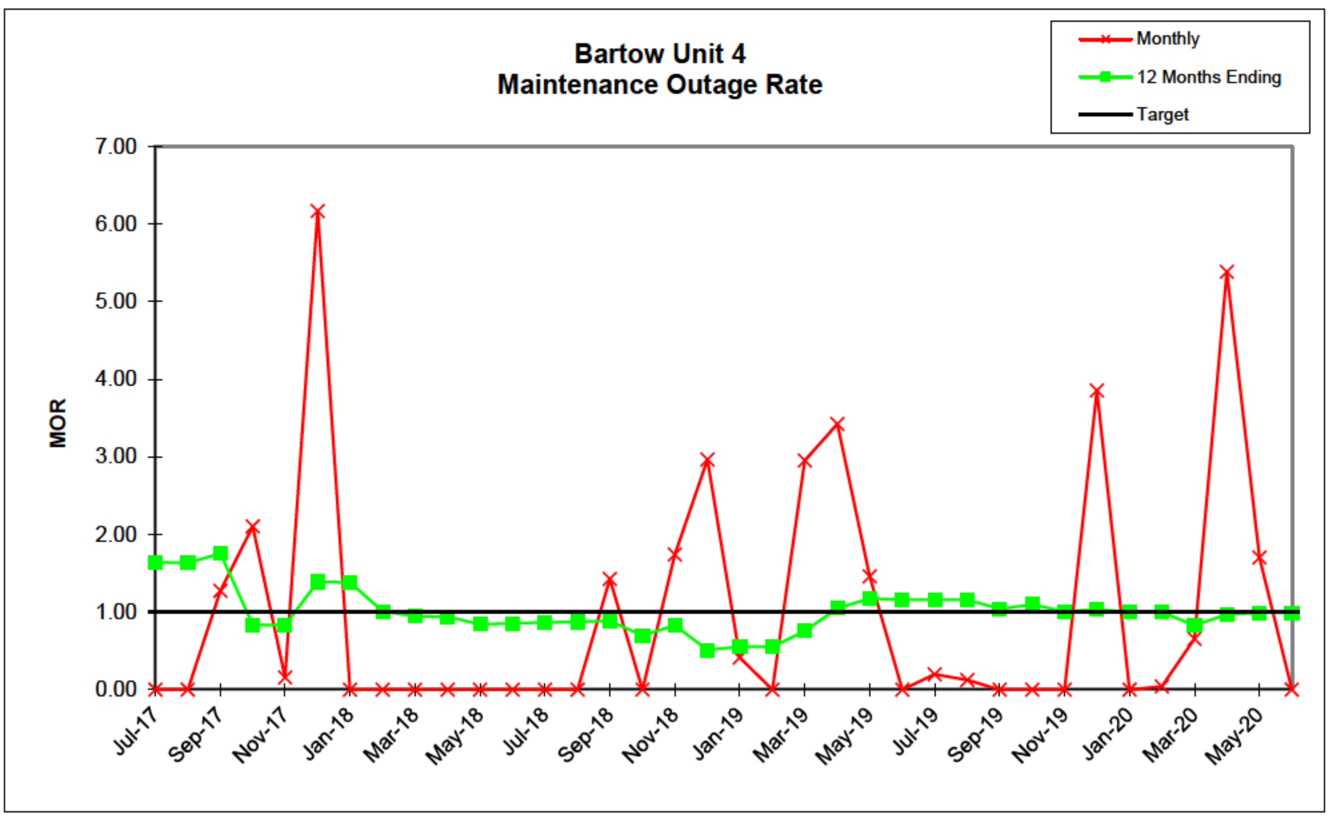
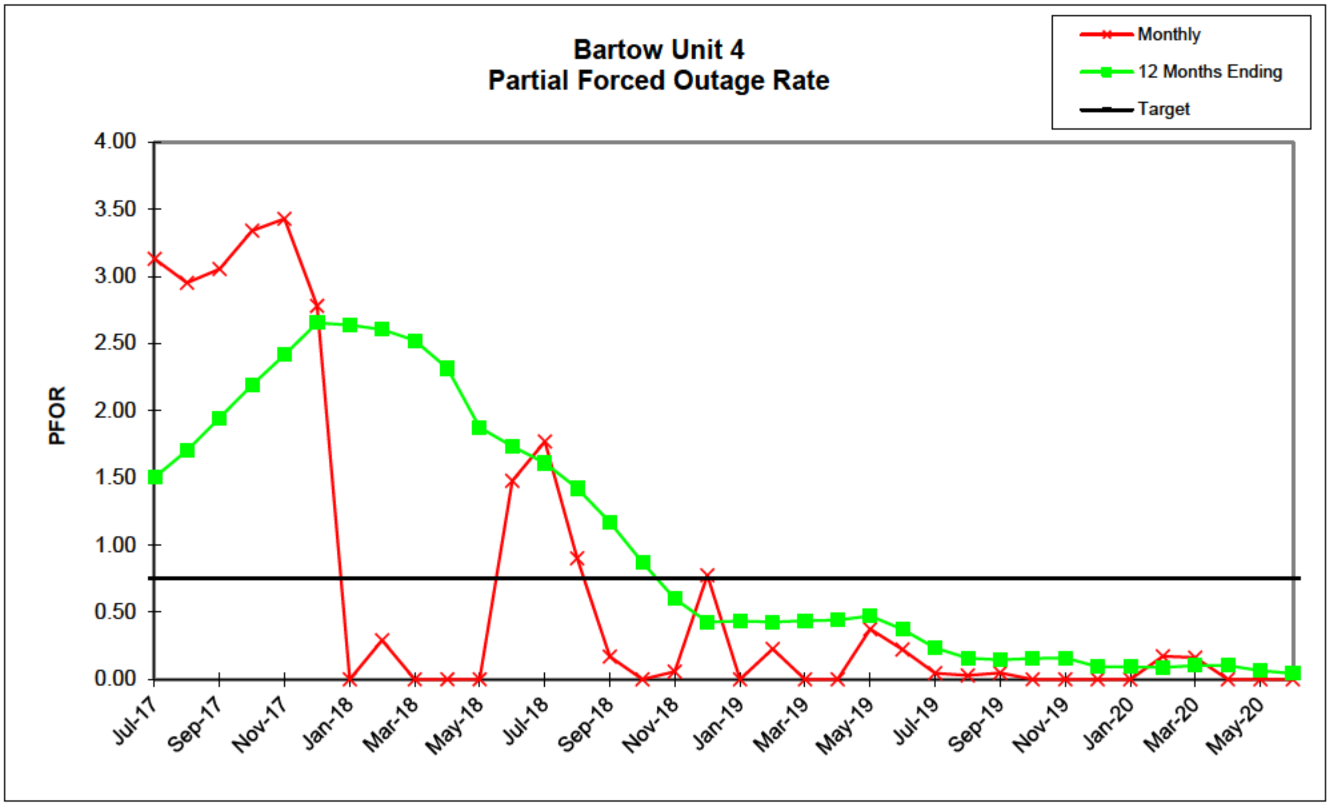
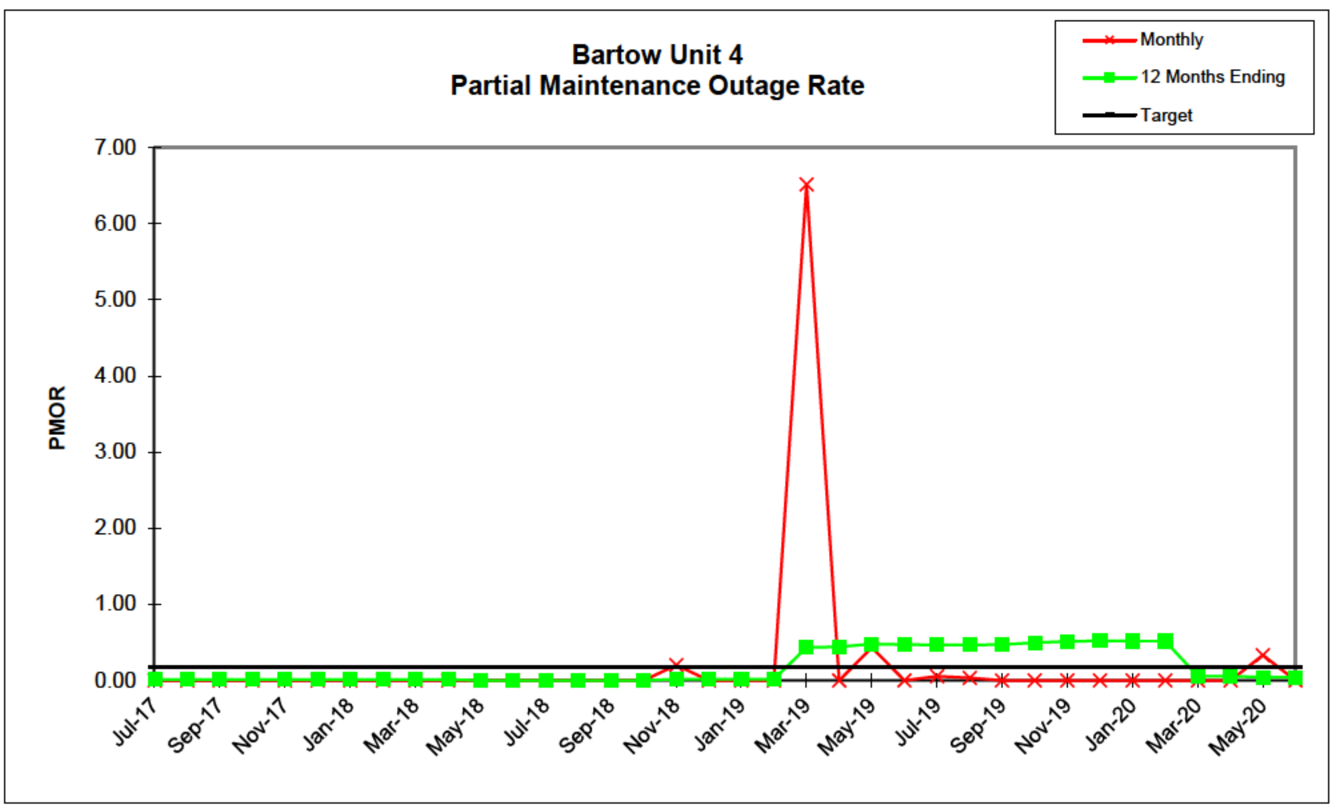
Jan-20
Mar-20
May-20


Bartow Unit 4
Maintenance Outage Rate
Monthly
12 Months Ending
Target
MOR
7.00
6.00
5.00
4.00
3.00
2.00
1.00
0.00
Jul-17
Sep-17
Nov-17
Jan-18
Mar-18
May-18
Jul-18
Sep-18
Nov-18
Jan-19
Mar-19
May-19
Jul-19
Sep-19
Nov-19
Jan-20
Mar-20
May-20


Bartow Unit 4
Partial Forced Outage Rate
Monthly
12 Months Ending
Target
PFOR
4.00
3.50
3.00
2.50
2.00
1.50
1.00
0.50
0.00
Jul-17
Sep-17
Nov-17
Jan-18
Mar-18
May-18
Jul-18
Sep-18
Nov-18
Jan-19
Mar-19
May-19
Jul-19
Sep-19
Nov-19
Jan-20
Mar-20
May-20


Bartow Unit 4
Partial Maintenance Outage Rate
Monthly
12 Months Ending
Target
PMOR
7.00
6.00
5.00
4.00
3.00
2.00
1.00
0.00
Jul-17
Sep-17
Nov-17
Jan-18
Mar-18
May-18
Jul-18
Sep-18
Nov-18
Jan-19
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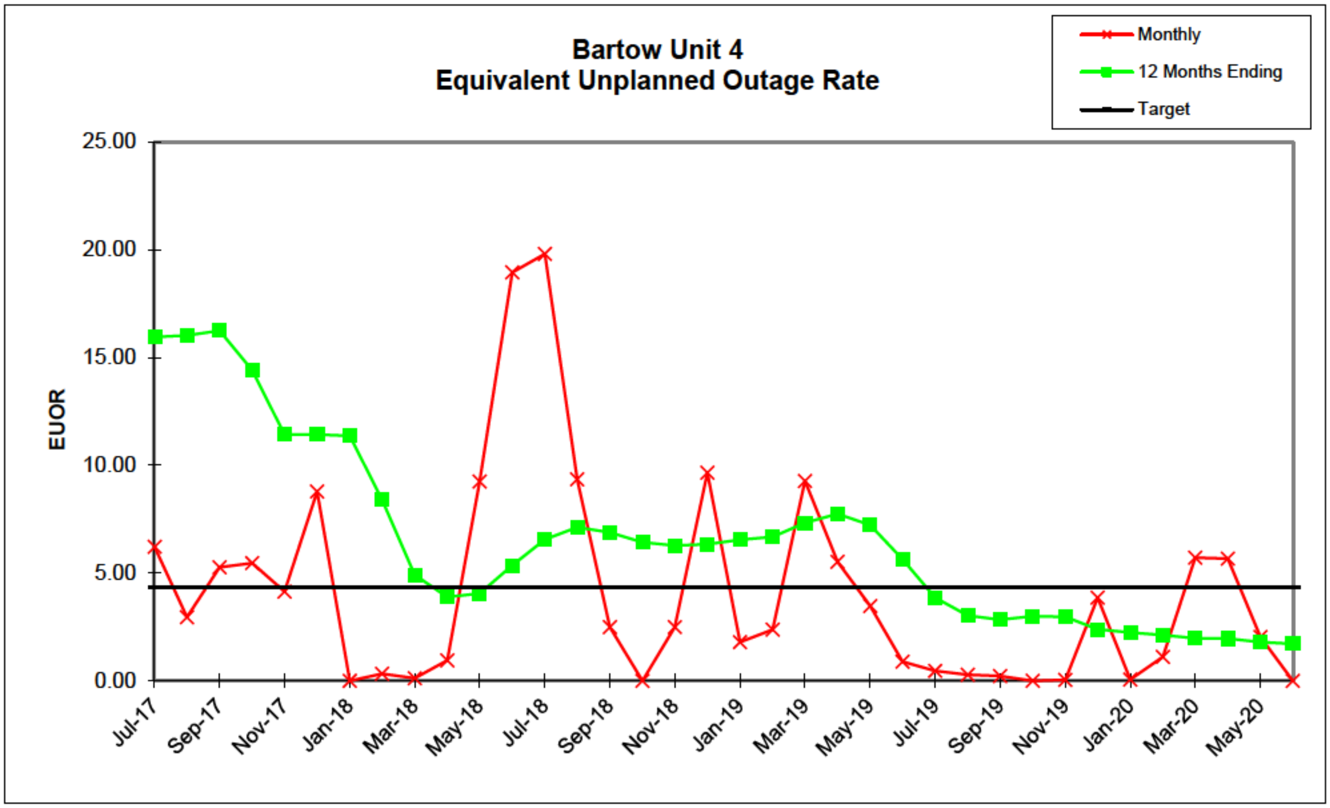
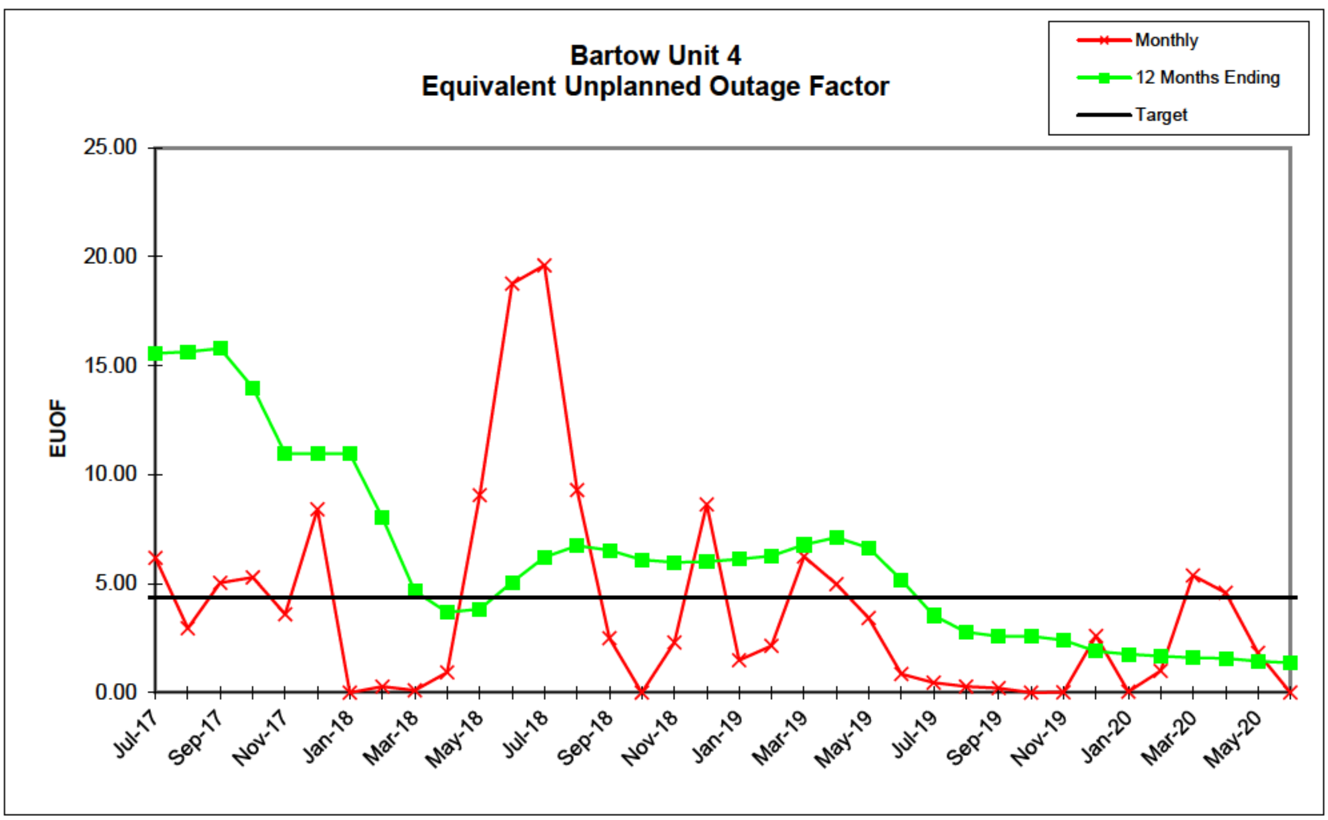
May-19
Jul-19
Sep-19
Nov-19
Jan-20
Mar-20
May-20


Bartow Unit 4
Equivalent Unplanned Outage Rate
Monthly
12 Months Ending
Target
EUOR
25.00
20.00
15.00
10.00
5.00
0.00
Jul-17
Sep-17
Nov-17
Jan-18
Mar-18
May-18
Jul-18
Sep-18
Nov-18
Jan-19
Mar-19
May-19
Jul-19
Sep-19
Nov-19
Jan-20
Mar-20
May-20


Bartow Unit 4
Equivalent Unplanned Outage Factor
Monthly
12 Months Ending
Target
EUOF
25.00
20.00
15.00
10.00
5.00
0.00
Jul-17
Sep-17
Nov-17
Jan-18
Mar-18
May-18
Jul-18
Sep-18
Nov-18
Jan-19
Mar-19
May-19
Jul-19
Sep-19
Nov-19
Jan-20
Mar-20
May-20

Crystal River
Unit 4

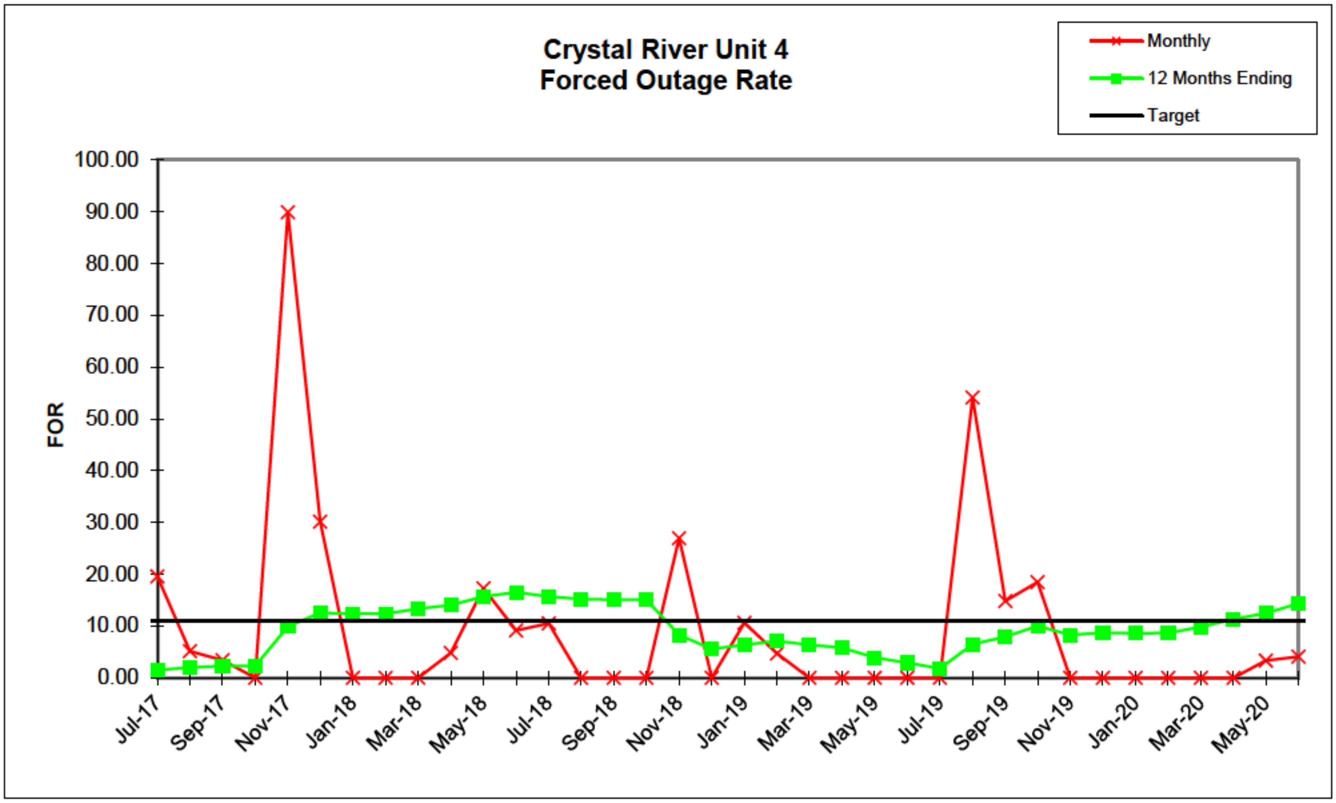
	Jul-17	Aug-17	Sep-17	Oct-17	Nov-17	Dec-17	Jan-18	Feb-18	Mar-18	Apr-18	May-18	Jun-18	Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18
PER HOURS	744.00	744.00	720.00	744.00	721.00	744.00	744.00	672.00	743.00	720.00	744.00	720.00	744.00	744.00	720.00	744.00	721.00	744.00
SER HOURS	505.35	705.75	695.30	744.00	72.78	519.57	744.00	672.00	47.78	482.33	615.00	654.25	665.55	744.00	637.70	744.00	236.67	313.82
RSH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	247.98	414.50
UH	238.65	38.25	24.70	0.00	648.22	224.43	0.00	0.00	695.22	237.67	129.00	65.75	78.45	0.00	82.30	0.00	236.35	15.68
POH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	695.22	211.03	0.00	0.00	0.00	0.00	0.00	0.00	148.98	15.68
FOH	123.38	38.25	24.70	0.00	648.22	224.43	0.00	0.00	0.00	24.63	129.00	65.75	78.45	0.00	0.00	0.00	87.37	0.00
MOH	115.27	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	2.00	0.00	0.00	0.00	0.00	82.30	0.00	0.00	0.00
PFOH	77.98	9.00	90.28	0.92	0.00	0.83	65.74	6.48	0.00	5.95	39.72	0.00	20.43	8.08	125.70	2.00	0.00	11.73
LRPF	494.02	93.00	334.75	92.66	0.00	93.37	339.02	93.05	0.00	93.00	106.76	0.00	161.37	99.47	63.14	93.00	0.00	209.88
EFOH	54.11	1.18	42.45	0.12	0.00	0.11	31.30	0.85	0.00	0.78	5.96	0.00	4.63	1.13	11.15	0.26	0.00	3.46
PMOH	0.00	0.00	5.73	1.63	0.00	0.00	0.00	0.00	0.00	34.08	13.35	0.00	0.00	0.00	3.00	0.50	0.00	0.00
LRPM	0.00	0.00	93.05	561.15	0.00	0.00	0.00	0.00	0.00	160.04	331.00	0.00	0.00	0.00	93.00	284.00	0.00	0.00
EMOH	0.00	0.00	0.75	1.28	0.00	0.00	0.00	0.00	0.00	7.66	6.21	0.00	0.00	0.00	0.39	0.20	0.00	0.00
NPC	712.00	712.00	712.00	712.00	712.00	712.00	712.00	712.00	712.00	712.00	712.00	712.00	712.00	712.00	712.00	712.00	712.00	712.00
MONTHLY	**Jul-17**	**Aug-17**	**Sep-17**	**Oct-17**	**Nov-17**	**Dec-17**	**Jan-18**	**Feb-18**	**Mar-18**	**Apr-18**	**May-18**	**Jun-18**	**Jul-18**	**Aug-18**	**Sep-18**	**Oct-18**	**Nov-18**	**Dec-18**
FOR	19.62	5.14	3.43	0.00	89.91	30.17	0.00	0.00	0.00	4.86	17.34	9.13	10.54	0.00	0.00	0.00	26.96	0.00
MOR	18.57	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.41	0.00	0.00	0.00	0.00	11.43	0.00	0.00	0.00
PFOR	10.71	0.17	6.10	0.02	0.00	0.02	4.21	0.13	0.00	0.16	0.97	0.00	0.70	0.15	1.75	0.04	0.00	1.10
PMOR	0.00	0.00	0.11	0.17	0.00	0.00	0.00	0.00	0.00	1.59	1.01	0.00	0.00	0.00	0.06	0.03	0.00	0.00
EUOR	39.35	5.30	9.43	0.19	89.91	30.18	4.21	0.13	0.00	6.89	18.97	9.13	11.17	0.15	13.03	0.06	26.96	1.10
EUOF	39.35	5.30	9.43	0.19	89.91	30.18	4.21	0.13	0.00	4.87	18.97	9.13	11.17	0.15	13.03	0.06	12.12	0.46
POF	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	93.57	29.31	0.00	0.00	0.00	0.00	0.00	0.00	20.66	2.11
EAF	60.65	94.70	90.57	99.81	10.09	69.82	95.79	99.87	6.43	65.82	81.03	90.87	88.83	99.85	86.97	99.94	67.22	97.43
12 MONTHS	**Jul-17**	**Aug-17**	**Sep-17**	**Oct-17**	**Nov-17**	**Dec-17**	**Jan-18**	**Feb-18**	**Mar-18**	**Apr-18**	**May-18**	**Jun-18**	**Jul-18**	**Aug-18**	**Sep-18**	**Oct-18**	**Nov-18**	**Dec-18**
FOR	1.52	1.98	2.27	2.27	9.89	12.54	12.40	12.37	13.38	14.07	15.73	16.52	15.71	15.22	15.07	15.07	8.27	5.55
MOR	4.33	4.35	4.36	4.36	3.56	3.66	2.43	2.15	1.69	1.78	1.82	1.78	0.03	0.03	1.26	1.26	1.23	1.27
PFOR	1.28	1.07	1.39	1.37	1.47	1.51	1.85	1.84	1.99	2.05	2.11	2.12	1.32	1.31	0.85	0.85	0.83	0.91
PMOR	0.73	0.69	0.54	0.44	0.39	0.39	0.38	0.31	0.33	0.24	0.26	0.25	0.24	0.24	0.24	0.22	0.21	0.22
EUOR	7.62	7.81	8.25	8.14	14.42	16.97	16.18	15.87	16.63	17.33	19.00	19.72	17.05	16.56	16.89	16.88	10.25	7.73
EUOF	7.62	7.81	8.25	8.14	14.42	16.97	16.18	15.87	15.31	15.54	17.03	17.68	15.28	14.84	15.14	15.13	8.73	6.20
POF	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	7.94	10.35	10.35	10.35	10.35	10.35	10.35	10.35	12.05	12.23
EAF	92.38	92.19	91.75	91.86	85.58	83.03	83.82	84.13	76.76	74.12	72.62	71.98	74.37	74.81	74.51	74.52	79.23	81.57

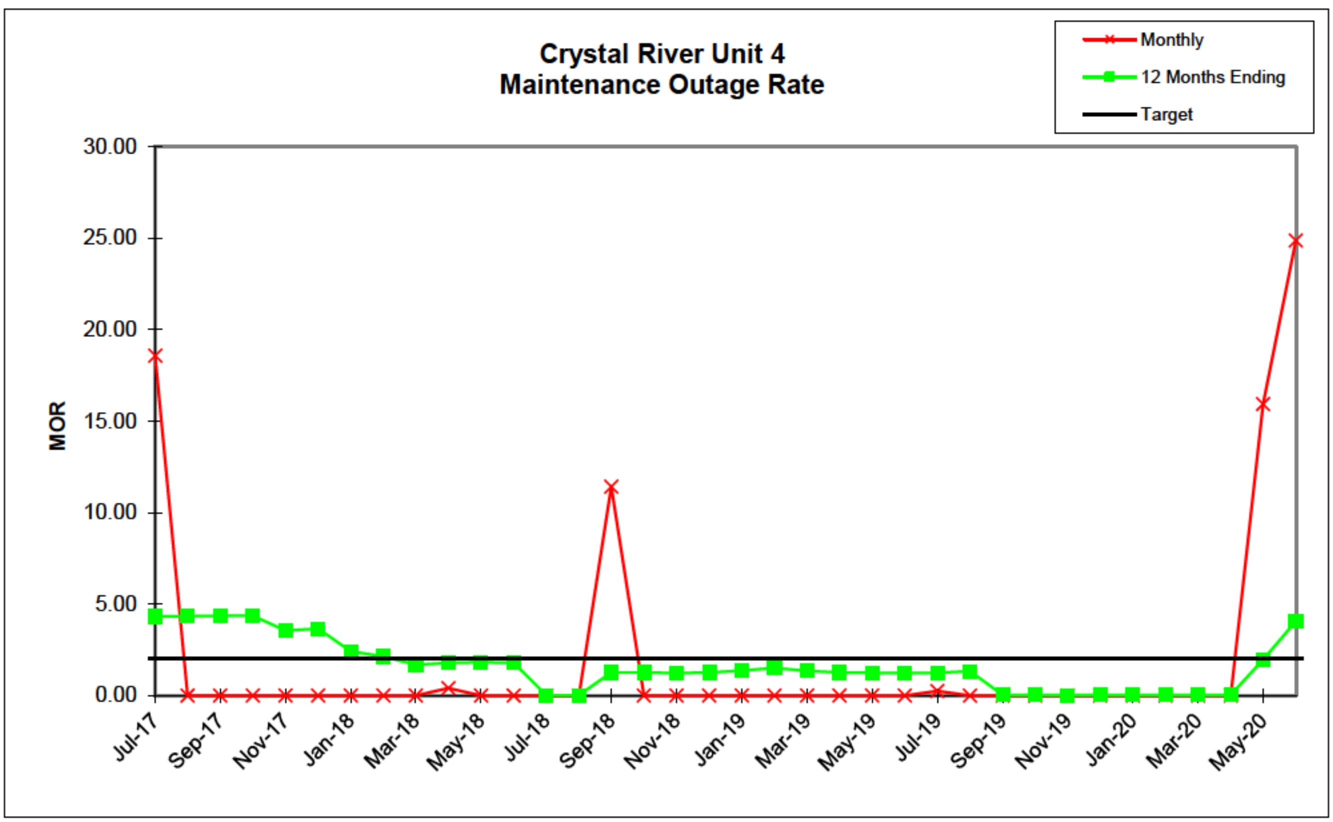
Crystal River
Unit 4

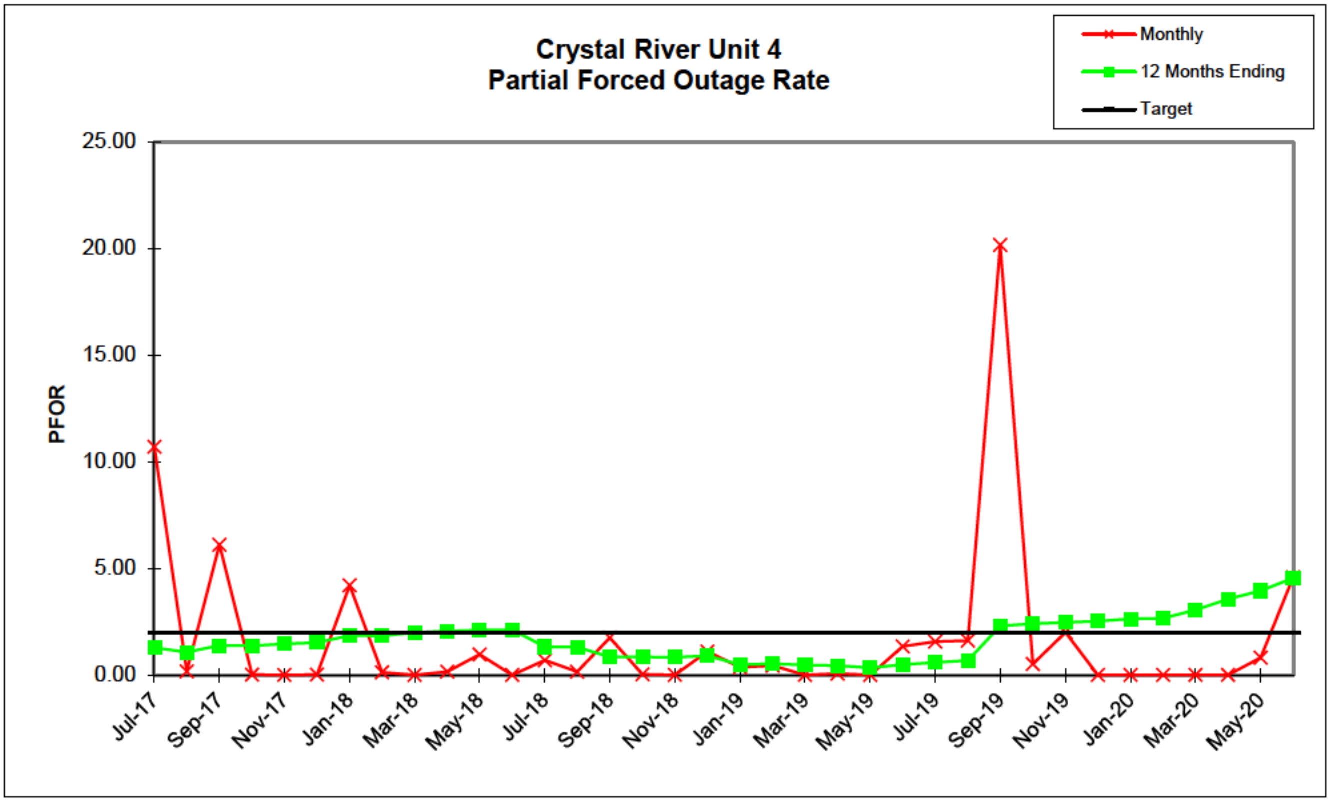
	Jan-19	Feb-19	Mar-19	Apr-19	May-19	Jun-19	Jul-19	Aug-19	Sep-19	Oct-19	Nov-19	Dec-19	Jan-20	Feb-20	Mar-20	Apr-20	May-20	Jun-20
PER HOURS	744.00	672.00	743.00	720.00	744.00	720.00	744.00	744.00	720.00	744.00	721.00	744.00	744.00	696.00	743.00	720.00	744.00	720.00
SER HOURS	248.95	85.33	743.00	720.00	744.00	720.00	742.15	263.35	545.87	606.38	627.60	0.00	0.00	0.00	0.00	0.00	404.67	196.20
RSH	465.47	582.43	0.00	0.00	0.00	0.00	0.00	169.83	79.07	0.00	69.42	264.00	744.00	336.00	0.00	0.00	50.90	450.40
UH	29.58	4.23	0.00	0.00	0.00	0.00	1.85	310.82	95.07	137.62	23.98	480.00	0.00	360.00	743.00	720.00	288.43	73.40
POH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	23.98	480.00	0.00	360.00	743.00	720.00	197.58	0.00
FOH	29.58	4.23	0.00	0.00	0.00	0.00	0.00	310.82	95.07	137.62	0.00	0.00	0.00	0.00	0.00	0.00	14.08	8.40
MOH	0.00	0.00	0.00	0.00	0.00	0.00	1.85	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	76.77	65.00
PFOH	2.23	2.90	0.00	1.65	0.00	70.00	71.48	17.58	525.63	9.70	38.80	0.00	0.00	0.00	0.00	0.00	42.02	28.62
LRPF	284.43	93.00	0.00	188.00	0.00	98.19	115.21	171.04	149.10	231.94	231.13	0.00	0.00	0.00	0.00	0.00	56.18	223.83
EFOH	0.89	0.38	0.00	0.44	0.00	9.65	11.57	4.22	110.07	3.16	12.60	0.00	0.00	0.00	0.00	0.00	3.32	9.00
PMOH	0.00	31.00	0.00	0.00	3.33	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
LRPM	0.00	93.00	0.00	0.00	93.09	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
EMOH	0.00	4.05	0.00	0.00	0.44	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
NPC	712.00	712.00	712.00	712.00	712.00	712.00	712.00	712.00	712.00	712.00	712.00	712.00	712.00	712.00	712.00	712.00	712.00	712.00

MONTHLY	**Jan-19**	**Feb-19**	**Mar-19**	**Apr-19**	**May-19**	**Jun-19**	**Jul-19**	**Aug-19**	**Sep-19**	**Oct-19**	**Nov-19**	**Dec-19**	**Jan-20**	**Feb-20**	**Mar-20**	**Apr-20**	**May-20**	**Jun-20**
FOR	10.62	4.72	0.00	0.00	0.00	0.00	0.00	54.13	14.83	18.50	0.00	0.00	0.00	0.00	0.00	0.00	3.36	4.11
MOR	0.00	0.00	0.00	0.00	0.00	0.00	0.25	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	15.95	24.89
PFOR	0.36	0.44	0.00	0.06	0.00	1.34	1.56	1.60	20.17	0.52	2.01	0.00	0.00	0.00	0.00	0.00	0.82	4.59
PMOR	0.00	4.75	0.00	0.00	0.06	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
EUOR	10.94	9.67	0.00	0.06	0.06	1.34	1.80	54.87	32.01	18.92	2.01	0.00	0.00	0.00	0.00	0.00	19.00	30.56
EUOF	4.10	1.29	0.00	0.06	0.06	1.34	1.80	42.34	28.49	18.92	1.75	0.00	0.00	0.00	0.00	0.00	12.66	11.44
POF	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	3.33	64.52	0.00	51.72	100.00	100.00	26.56	0.00
EAF	95.90	98.71	100.00	99.94	99.94	98.66	98.20	57.66	71.51	81.08	94.93	35.48	100.00	48.28	0.00	0.00	60.79	88.56

12 MONTHS	**Jan-19**	**Feb-19**	**Mar-19**	**Apr-19**	**May-19**	**Jun-19**	**Jul-19**	**Aug-19**	**Sep-19**	**Oct-19**	**Nov-19**	**Dec-19**	**Jan-20**	**Feb-20**	**Mar-20**	**Apr-20**	**May-20**	**Jun-20**
FOR	6.40	7.11	6.36	5.80	3.90	2.93	1.78	6.51	7.94	10.02	8.32	8.72	8.63	8.69	9.86	11.34	12.48	14.32
MOR	1.37	1.52	1.35	1.27	1.24	1.23	1.24	1.34	0.03	0.03	0.03	0.03	0.03	0.03	0.04	0.04	1.97	4.07
PFOR	0.48	0.52	0.46	0.44	0.34	0.48	0.58	0.68	2.31	2.41	2.46	2.53	2.62	2.66	3.05	3.56	3.95	4.55
PMOR	0.24	0.34	0.30	0.17	0.08	0.08	0.08	0.08	0.08	0.08	0.07	0.07	0.08	0.01	0.01	0.01	0.00	0.00
EUOR	8.27	9.21	8.25	7.49	5.45	4.63	3.62	8.39	10.16	12.28	10.66	11.12	11.13	11.15	12.65	14.54	17.39	21.08
EUOF	6.19	6.28	6.28	5.89	4.28	3.64	2.85	6.43	7.70	9.30	8.45	8.41	8.06	7.94	7.94	7.94	9.00	9.83
POF	12.23	12.23	4.29	1.88	1.88	1.88	1.88	1.88	1.88	1.88	0.45	5.75	5.75	9.84	18.29	26.49	28.74	28.74
EAF	81.58	81.49	89.43	92.23	93.84	94.48	95.27	91.69	90.42	88.82	91.10	85.84	86.19	82.22	73.76	65.57	62.26	61.43


Crystal River Unit 4
Forced Outage Rate
Monthly
12 Months Ending
Target
FOR
100.00
90.00
80.00
70.00
60.00
50.00
40.00
30.00
20.00
10.00
0.00
Jul-17
Sep-17
Nov-17
Jan-18
Mar-18
May-18
Jul-18
Sep-18
Nov-18
Jan-19
Mar-19
May-19
Jul-19
Sep-19
Nov-19
Jan-20
Mar-20
May-20


Crystal River Unit 4
Maintenance Outage Rate
Monthly
12 Months Ending
Target
MOR
30.00
25.00
20.00
15.00
10.00
5.00
0.00
Jul-17
Sep-17
Nov-17
Jan-18
Mar-18
May-18
Jul-18
Sep-18
Nov-18
Jan-19
Mar-19
May-19
Jul-19
Sep-19
Nov-19
Jan-20
Mar-20
May-20


Crystal River Unit 4
Partial Forced Outage Rate
Monthly
12 Months Ending
Target
PFOR
25.00
20.00
15.00
10.00
5.00
0.00
Jul-17
Sep-17
Nov-17
Jan-18
Mar-18
May-18
Jul-18
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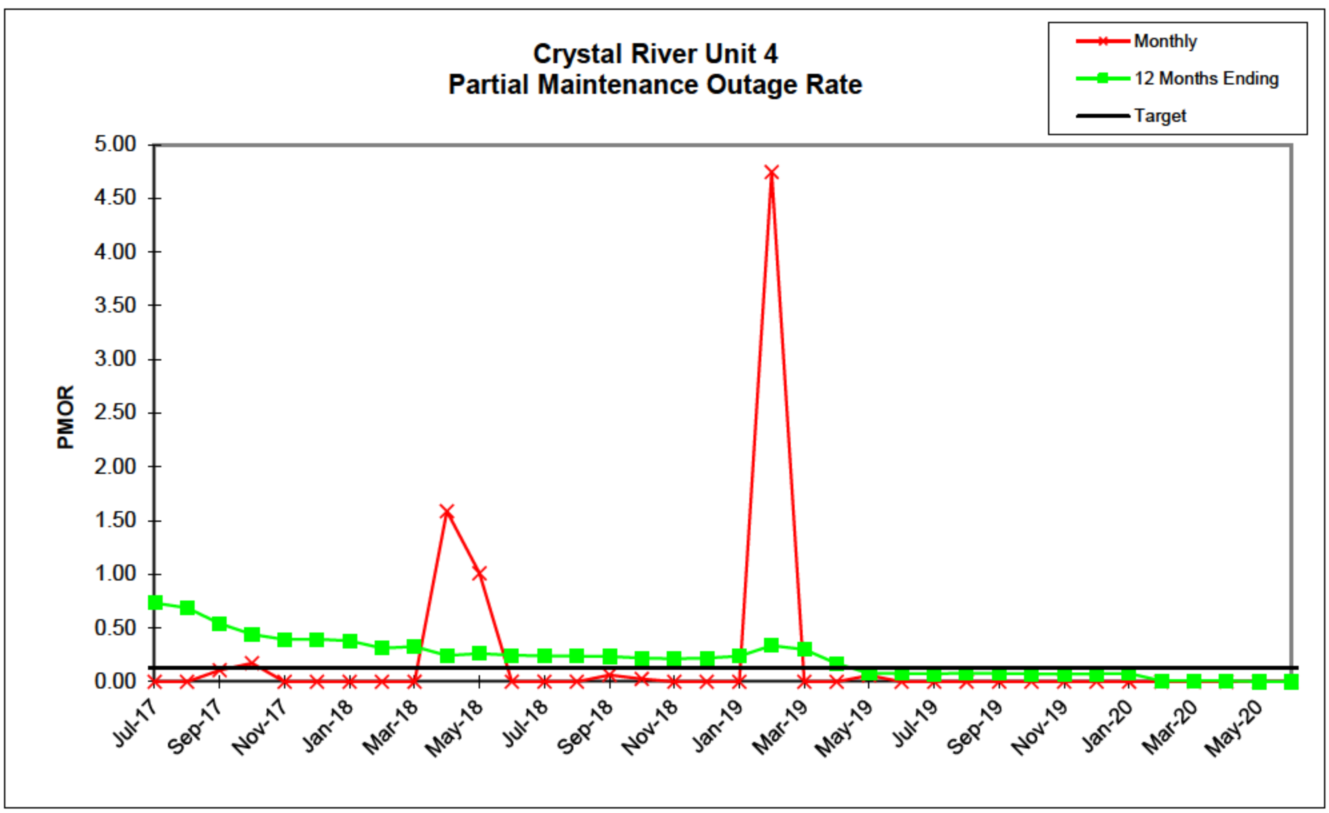
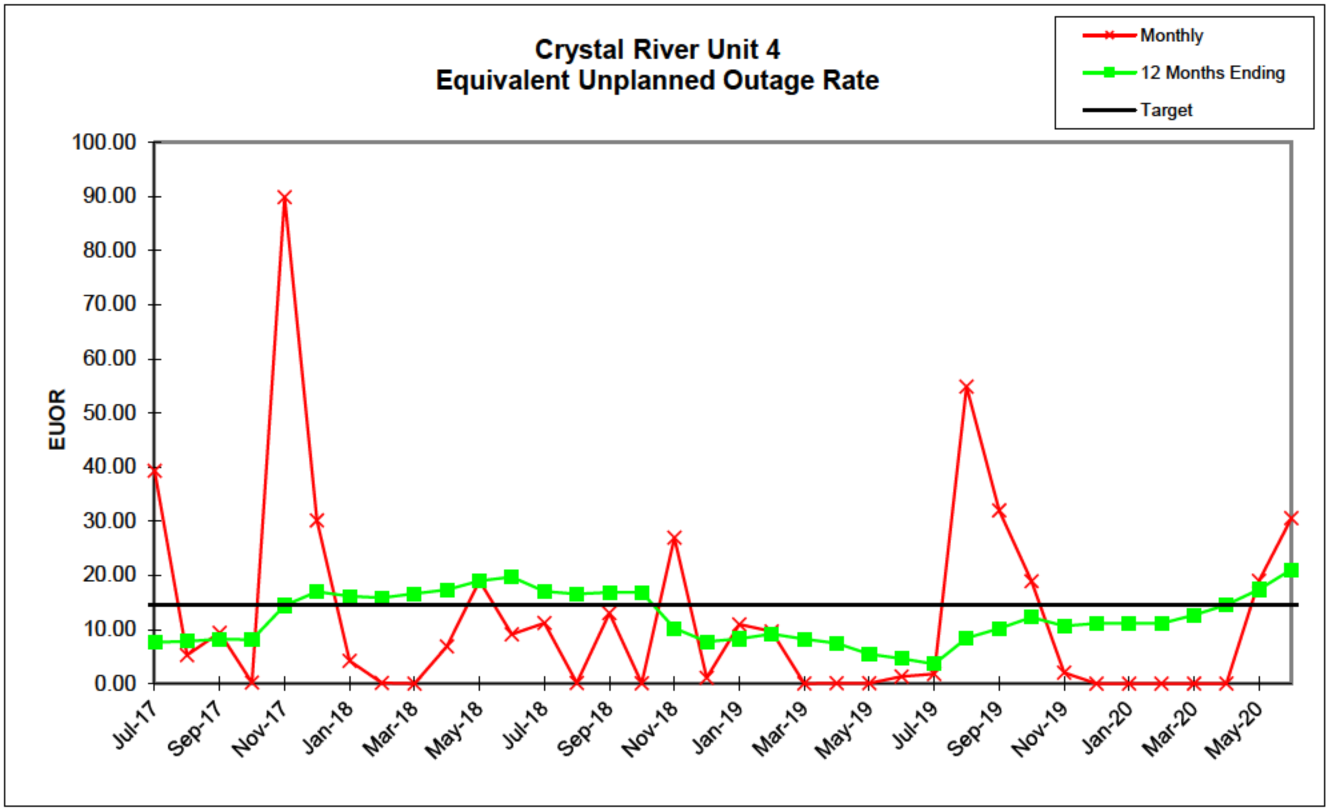
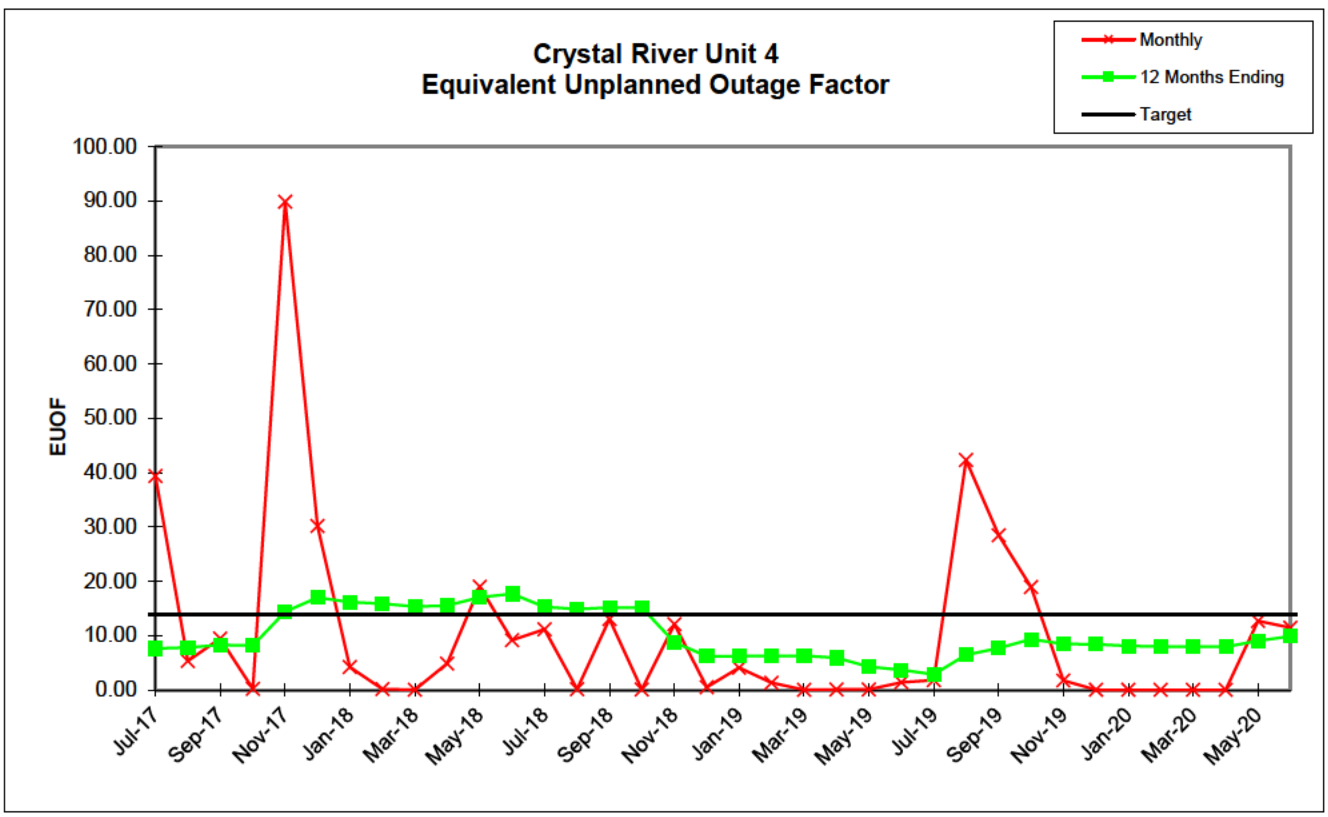
Jan-20
Mar-20
May-20


Crystal River Unit 4
Partial Maintenance Outage Rate
Monthly
12 Months Ending
Target
PMOR
5.00
4.50
4.00
3.50
3.00
2.50
2.00
1.50
1.00
0.50
0.00
Jul-17
Sep-17
Nov-17
Jan-18
Mar-18
May-18
Jul-18
Sep-18
Nov-18
Jan-19
Mar-19
May-19
Jul-19
Sep-19
Nov-19
Jan-20
Mar-20
May-20


Crystal River Unit 4
Equivalent Unplanned Outage Rate
Monthly
12 Months Ending
Target
EUOR
100.00
90.00
80.00
70.00
60.00
50.00
40.00
30.00
20.00
10.00
0.00
Jul-17
Sep-17
Nov-17
Jan-18
Mar-18
May-18
Jul-18
Sep-18
Nov-18
Jan-19
Mar-19
May-19
Jul-19
Sep-19
Nov-19
Jan-20
Mar-20
May-20


Crystal River Unit 4
Equivalent Unplanned Outage Factor
Monthly
12 Months Ending
Target
EUOF
100.00
90.00
80.00
70.00
60.00
50.00
40.00
30.00
20.00
10.00
0.00
Jul-17
Sep-17
Nov-17
Jan-18
Mar-18
May-18
Jul-18
Sep-18
Nov-18
Jan-19
Mar-19
May-19
Jul-19
Sep-19
Nov-19
Jan-20
Mar-20
May-20

Crystal River
Unit 5

	Jul-17	Aug-17	Sep-17	Oct-17	Nov-17	Dec-17	Jan-18	Feb-18	Mar-18	Apr-18	May-18	Jun-18	Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18
PER HOURS	744.00	744.00	720.00	744.00	721.00	744.00	744.00	672.00	743.00	720.00	744.00	720.00	744.00	744.00	720.00	744.00	721.00	744.00
SER HOURS	744.00	744.00	591.83	479.50	0.00	16.05	744.00	668.00	730.30	368.40	627.72	718.25	293.52	744.00	720.00	744.00	700.05	636.30
RSH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
UH	0.00	0.00	128.17	264.50	721.00	727.95	0.00	4.00	12.70	351.60	116.28	1.75	450.48	0.00	0.00	0.00	20.95	107.70
POH	0.00	0.00	0.00	264.50	721.00	727.95	0.00	0.00	0.00	351.60	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
FOH	0.00	0.00	82.63	0.00	0.00	0.00	0.00	0.00	12.70	0.00	116.28	0.00	450.48	0.00	0.00	0.00	20.95	0.00
MOH	0.00	0.00	45.53	0.00	0.00	0.00	0.00	4.00	0.00	0.00	0.00	1.75	0.00	0.00	0.00	0.00	0.00	107.70
PFOH	0.00	4.50	0.00	0.00	0.00	0.00	36.45	0.00	5.00	0.00	3.00	2.84	16.76	1.50	0.00	0.00	19.48	59.37
LRPF	0.00	91.00	0.00	0.00	0.00	0.00	296.03	0.00	377.00	0.00	496.00	90.79	236.17	53.00	0.00	0.00	240.51	187.77
EFOH	0.00	0.58	0.00	0.00	0.00	0.00	15.20	0.00	2.65	0.00	2.10	0.36	5.58	0.11	0.00	0.00	6.60	15.70
PMOH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	22.50	0.00	0.00	0.00	23.83	0.00	4.52	0.00	0.00	0.00	1.83
LRPM	0.00	0.00	0.00	0.00	0.00	0.00	0.00	496.00	0.00	0.00	0.00	91.01	0.00	90.93	0.00	0.00	0.00	91.16
EMOH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	15.72	0.00	0.00	0.00	3.05	0.00	0.58	0.00	0.00	0.00	0.23
NPC	710.00	710.00	710.00	710.00	710.00	710.00	710.00	710.00	710.00	710.00	710.00	710.00	710.00	710.00	710.00	710.00	710.00	710.00

MONTHLY	**Jul-17**	**Aug-17**	**Sep-17**	**Oct-17**	**Nov-17**	**Dec-17**	**Jan-18**	**Feb-18**	**Mar-18**	**Apr-18**	**May-18**	**Jun-18**	**Jul-18**	**Aug-18**	**Sep-18**	**Oct-18**	**Nov-18**	**Dec-18**
FOR	0.00	0.00	12.25	0.00	0.00	0.00	0.00	0.00	1.71	0.00	15.63	0.00	60.55	0.00	0.00	0.00	2.91	0.00
MOR	0.00	0.00	7.14	0.00	0.00	0.00	0.00	0.60	0.00	0.00	0.00	0.24	0.00	0.00	0.00	0.00	0.00	14.48
PFOR	0.00	0.08	0.00	0.00	0.00	0.00	2.04	0.00	0.36	0.00	0.33	0.05	1.90	0.02	0.00	0.00	0.94	2.47
PMOR	0.00	0.00	0.00	0.00	0.00	0.00	0.00	2.35	0.00	0.00	0.00	0.43	0.00	0.08	0.00	0.00	0.00	0.04
EUOR	0.00	0.08	17.80	0.00	0.00	0.00	2.04	2.93	2.07	0.00	15.91	0.72	61.30	0.09	0.00	0.00	3.82	16.62
EUOF	0.00	0.08	17.80	0.00	0.00	0.00	2.04	2.93	2.07	0.00	15.91	0.72	61.30	0.09	0.00	0.00	3.82	16.62
POF	0.00	0.00	0.00	35.55	100.00	97.84	0.00	0.00	0.00	48.83	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
EAF	100.00	99.92	82.20	64.45	0.00	2.16	97.96	97.07	97.93	51.17	84.09	99.28	38.70	99.91	100.00	100.00	96.18	83.38

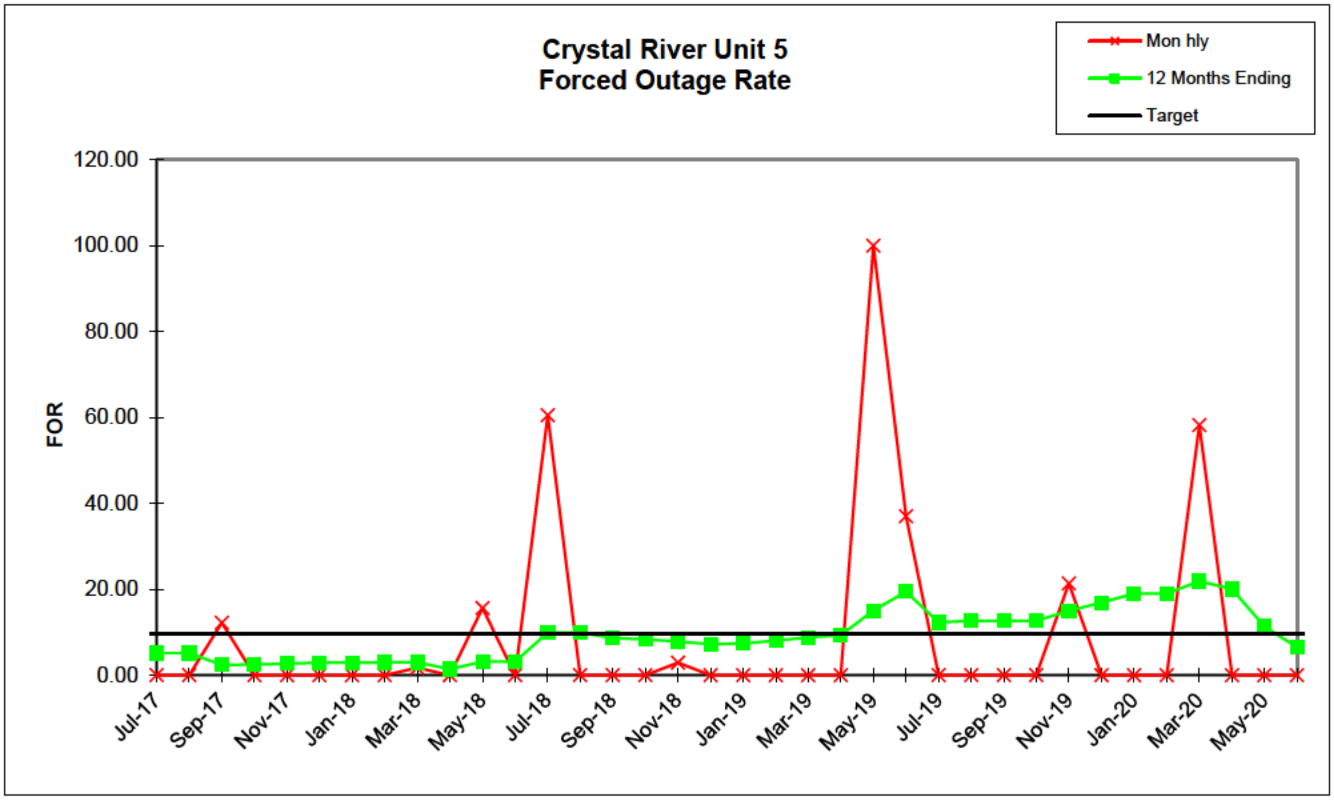
12 MONTHS	**Jul-17**	**Aug-17**	**Sep-17**	**Oct-17**	**Nov-17**	**Dec-17**	**Jan-18**	**Feb-18**	**Mar-18**	**Apr-18**	**May-18**	**Jun-18**	**Jul-18**	**Aug-18**	**Sep-18**	**Oct-18**	**Nov-18**	**Dec-18**
FOR	5.17	5.17	2.43	2.45	2.69	2.97	2.97	2.97	2.98	1.43	3.18	3.19	9.97	9.97	8.66	8.33	7.82	7.24
MOR	0.91	0.91	1.43	1.44	1.58	1.75	1.75	1.81	0.72	0.75	0.76	0.79	0.85	0.85	0.09	0.09	0.08	1.45
PFOR	0.40	0.23	0.17	0.17	0.17	0.19	0.42	0.42	0.43	0.44	0.41	0.32	0.44	0.43	0.43	0.41	0.46	0.63
PMOR	2.48	2.11	1.93	1.46	1.57	1.65	1.62	1.83	1.09	0.33	0.24	0.29	0.31	0.32	0.32	0.30	0.27	0.25
EUOR	8.70	8.19	5.81	5.39	5.85	6.37	6.56	6.81	5.12	2.91	4.53	4.52	11.33	11.33	9.42	9.06	8.57	9.30
EUOF	8.52	8.02	5.69	5.23	5.19	5.13	5.28	5.48	4.12	2.23	3.46	3.45	8.66	8.66	7.20	7.20	7.51	8.92
POF	2.07	2.07	2.07	3.02	11.25	19.56	19.56	19.56	19.56	23.57	23.57	23.57	23.57	23.57	23.57	20.55	12.32	4.01
EAF	89.41	89.91	92.23	91.75	83.56	75.31	75.16	74.96	76.32	74.20	72.96	72.97	67.77	67.77	69.23	72.25	80.16	87.06

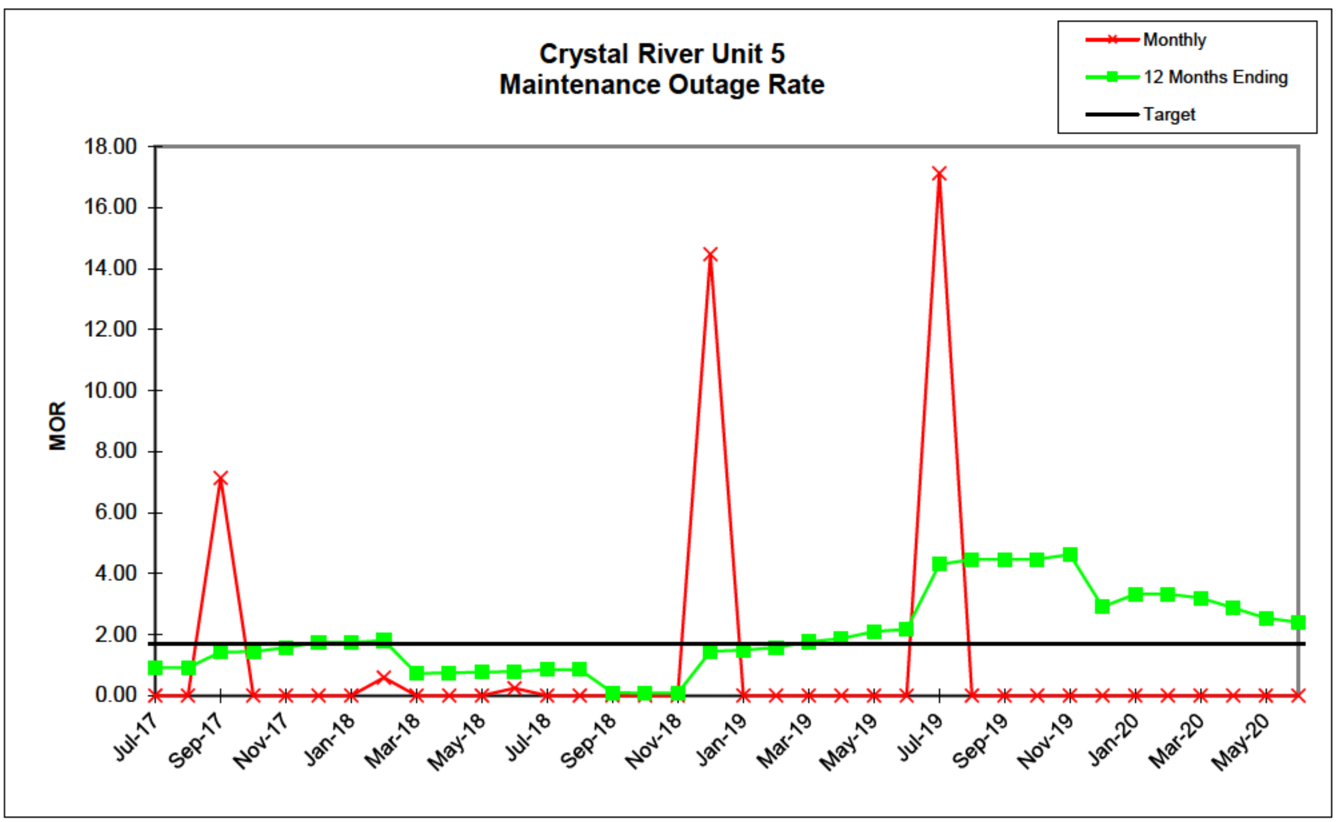
Crystal River
Unit 5

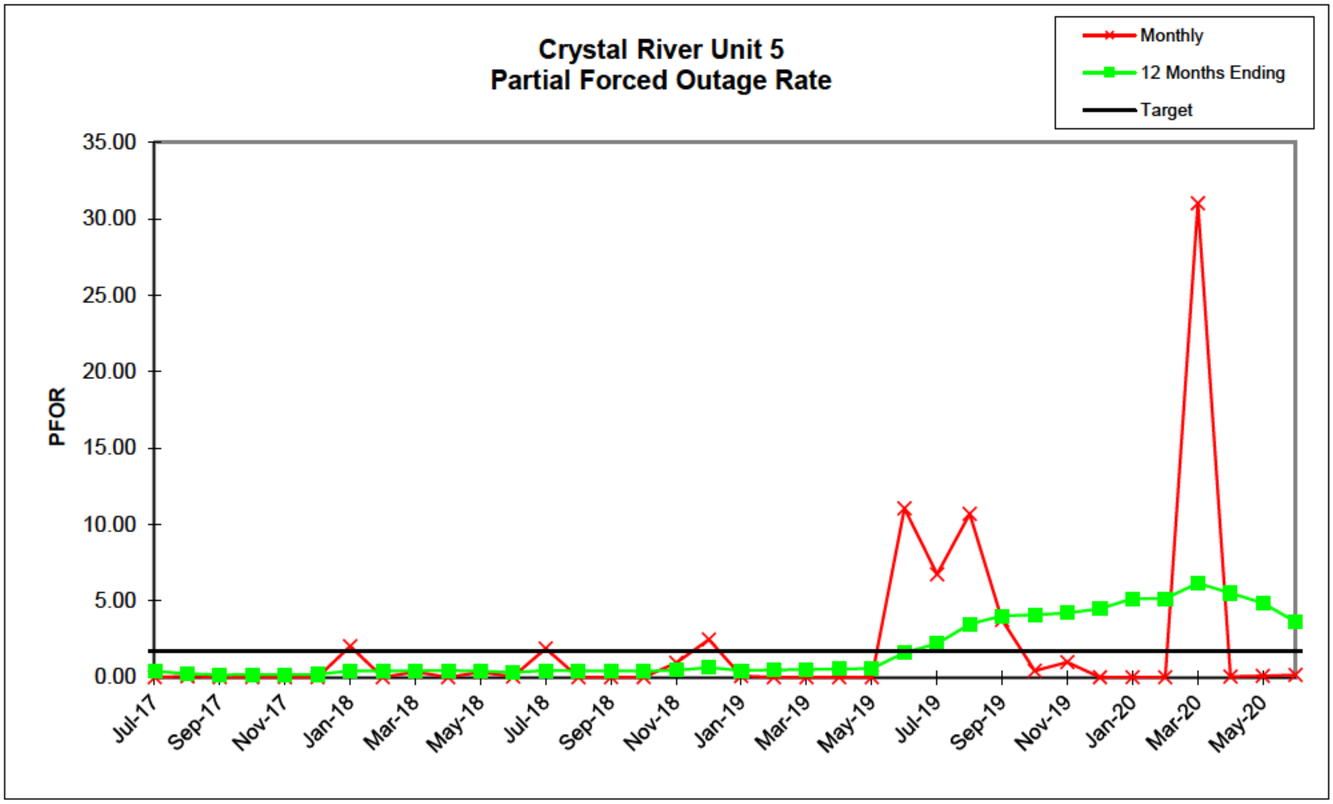
	Jan-19	Feb-19	Mar-19	Apr-19	May-19	Jun-19	Jul-19	Aug-19	Sep-19	Oct-19	Nov-19	Dec-19	Jan-20	Feb-20	Mar-20	Apr-20	May-20	Jun-20
PER HOURS	744.00	672.00	743.00	720.00	744.00	720.00	744.00	744.00	720.00	744.00	721.00	744.00	744.00	696.00	743.00	720.00	744.00	720.00
SER HOURS	547.67	0.00	0.00	0.00	0.00	453.31	598.25	551.58	711.58	744.00	527.58	0.00	0.00	0.00	145.98	442.75	573.57	720.00
RSH	196.33	528.00	0.00	0.00	0.00	0.00	22.05	192.42	8.42	0.00	25.87	264.00	744.00	696.00	393.43	277.25	170.43	0.00
UH	0.00	144.00	743.00	720.00	743.60	266.68	123.70	0.00	0.00	0.00	167.55	480.00	0.00	0.00	203.58	0.00	0.00	0.00
POH	0.00	144.00	743.00	720.00	311.02	0.00	0.00	0.00	0.00	0.00	23.98	480.00	0.00	0.00	0.00	0.00	0.00	0.00
FOH	0.00	0.00	0.00	0.00	432.58	266.68	0.00	0.00	0.00	0.00	143.57	0.00	0.00	0.00	203.58	0.00	0.00	0.00
MOH	0.00	0.00	0.00	0.00	0.00	0.00	123.70	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PFOH	1.00	0.00	0.00	0.00	0.00	585.29	402.50	435.01	67.71	8.00	40.48	0.00	0.00	0.00	92.08	2.50	5.50	22.33
LRPF	377.00	0.00	0.00	0.00	0.00	60.85	71.16	96.33	280.42	282.00	91.01	0.00	0.00	0.00	349.15	60.00	60.00	35.01
EFOH	0.53	0.00	0.00	0.00	0.00	50.17	40.34	59.02	26.74	3.18	5.19	0.00	0.00	0.00	45.28	0.21	0.46	1.10
PMOH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	9.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
LRPM	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	120.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
EMOH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.52	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
NPC	710.00	710.00	710.00	710.00	710.00	710.00	710.00	710.00	710.00	710.00	710.00	710.00	710.00	710.00	710.00	710.00	710.00	710.00

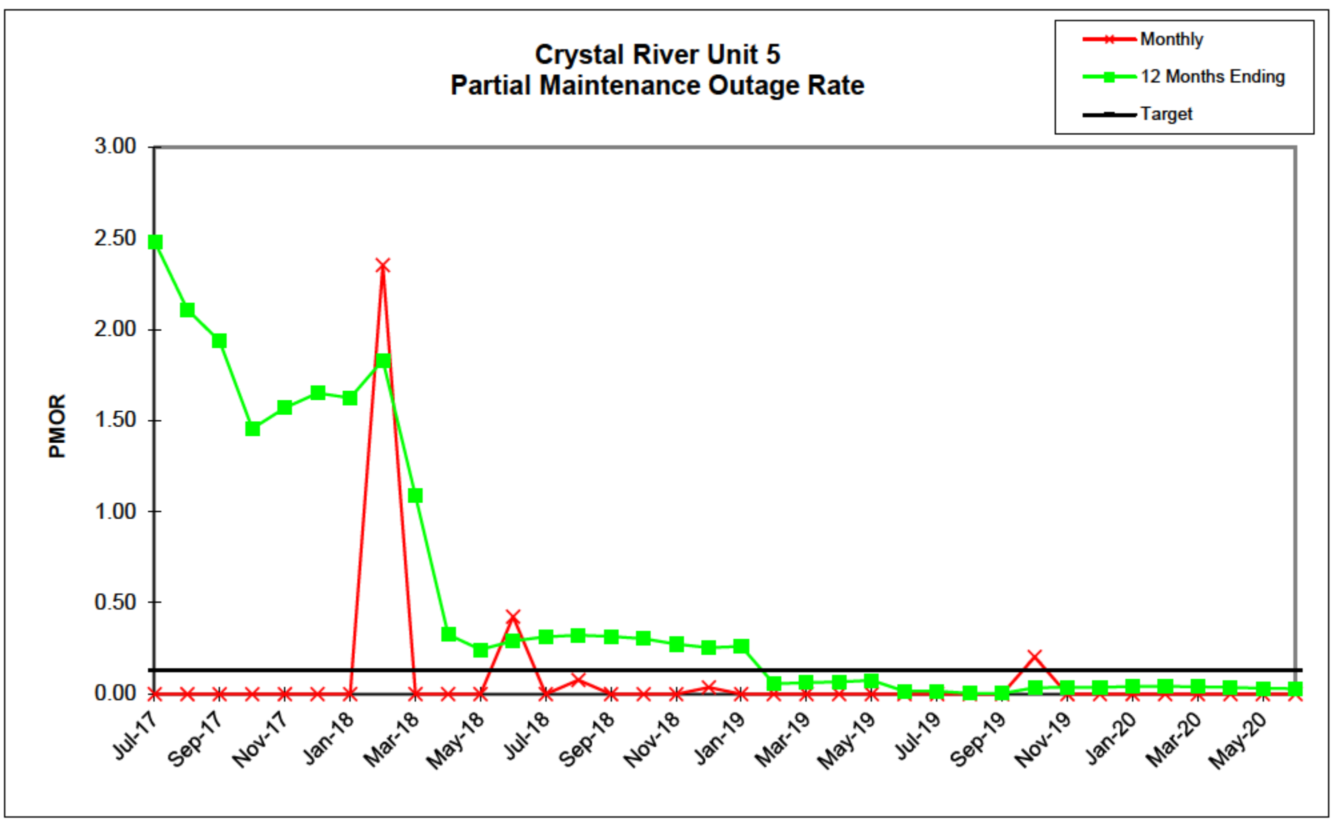
MONTHLY	**Jan-19**	**Feb-19**	**Mar-19**	**Apr-19**	**May-19**	**Jun-19**	**Jul-19**	**Aug-19**	**Sep-19**	**Oct-19**	**Nov-19**	**Dec-19**	**Jan-20**	**Feb-20**	**Mar-20**	**Apr-20**	**May-20**	**Jun-20**
FOR	0.00	0.00	0.00	0.00	100.00	37.04	0.00	0.00	0.00	0.00	21.39	0.00	0.00	0.00	58.24	0.00	0.00	0.00
MOR	0.00	0.00	0.00	0.00	0.00	0.00	17.13	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PFOR	0.10	0.00	0.00	0.00	0.00	11.07	6.74	10.70	3.76	0.43	0.98	0.00	0.00	0.00	31.02	0.05	0.08	0.15
PMOR	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.20	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
EUOR	0.10	0.00	0.00	0.00	100.00	44.01	22.72	10.70	3.76	0.63	22.16	0.00	0.00	0.00	71.19	0.05	0.08	0.15
EUOF	0.07	0.00	0.00	0.00	58.14	44.01	22.05	7.93	3.71	0.63	20.63	0.00	0.00	0.00	33.49	0.03	0.06	0.15
POF	0.00	21.43	100.00	100.00	41.80	0.00	0.00	0.00	0.00	0.00	3.33	64.52	0.00	0.00	0.00	0.00	0.00	0.00
EAF	99.93	78.57	0.00	0.00	0.05	55.99	77.95	92.07	96.29	99.37	76.04	35.48	100.00	100.00	66.51	99.97	99.94	99.85

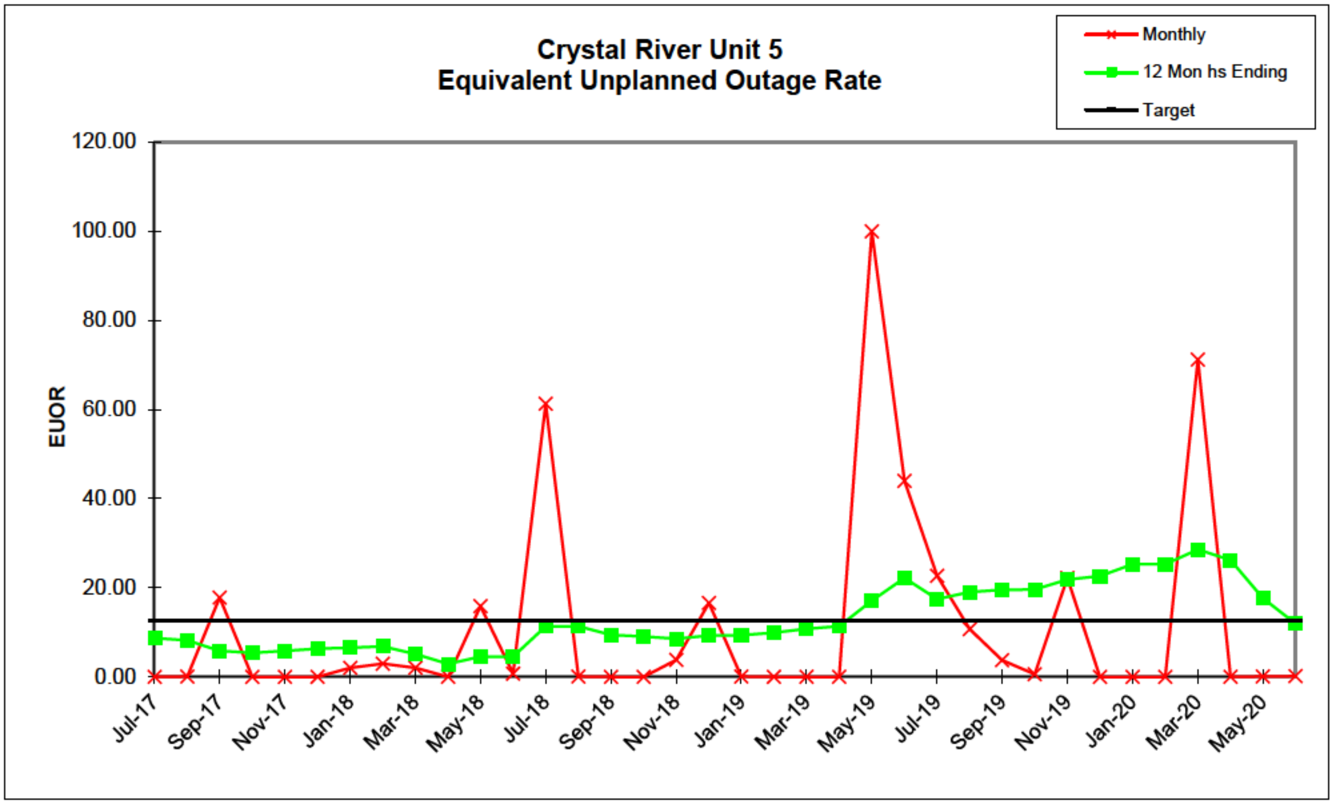
12 MONTHS	**Jan-19**	**Feb-19**	**Mar-19**	**Apr-19**	**May-19**	**Jun-19**	**Jul-19**	**Aug-19**	**Sep-19**	**Oct-19**	**Nov-19**	**Dec-19**	**Jan-20**	**Feb-20**	**Mar-20**	**Apr-20**	**May-20**	**Jun-20**
FOR	7.41	8.08	8.79	9.30	15.05	19.48	12.28	12.70	12.72	12.72	15.02	16.94	19.03	19.03	21.90	20.04	11.45	6.47
MOR	1.49	1.58	1.76	1.87	2.10	2.18	4.31	4.46	4.47	4.47	4.63	2.91	3.33	3.33	3.21	2.88	2.54	2.41
PFOR	0.45	0.49	0.51	0.54	0.57	1.63	2.21	3.48	4.03	4.09	4.21	4.48	5.15	5.15	6.16	5.51	4.86	3.62
PMOR	0.26	0.06	0.06	0.07	0.08	0.02	0.02	0.00	0.00	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.03	0.03
EUOR	9.34	9.91	10.77	11.39	17.10	22.20	17.49	19.05	19.53	19.61	21.85	22.61	25.32	25.32	28.59	26.22	17.67	11.92
EUOF	8.76	8.53	8.36	8.36	11.94	15.50	12.17	12.83	13.14	13.19	14.58	13.16	13.16	13.12	15.96	15.96	11.04	7.44
POF	4.01	5.66	14.14	18.34	21.90	21.90	21.90	21.90	21.90	21.90	22.17	27.65	27.65	25.93	17.47	9.28	5.74	5.74
EAF	87.23	85.81	77.50	73.30	66.16	62.60	65.94	65.27	64.97	64.91	63.26	59.19	59.19	60.94	66.57	74.76	83.22	86.82

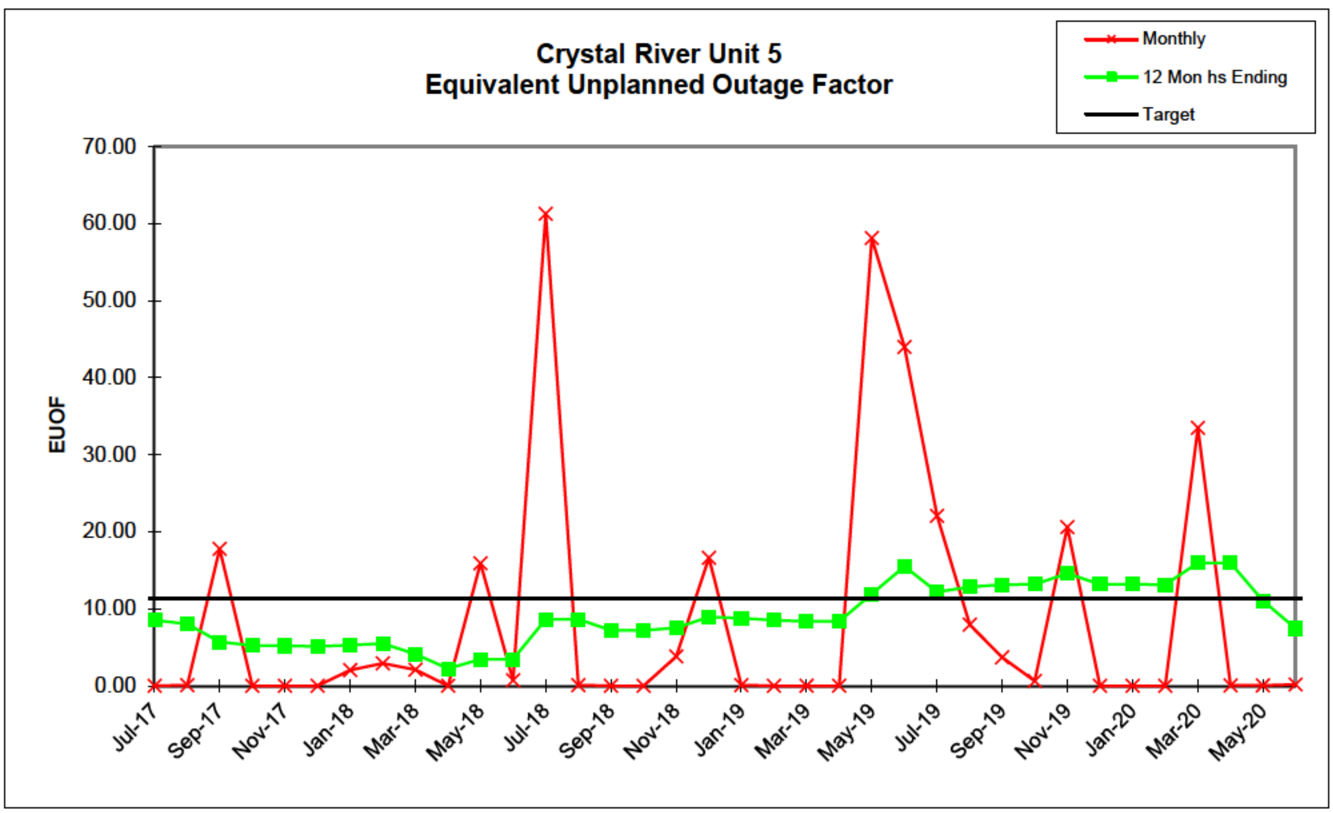

Crystal River Unit 5
Forced Outage Rate
Mon hly
12 Months Ending
Target
FOR
120.00
100.00
80.00
60.00
40.00
20.00
0.00
Jul-17
Sep-17
Nov-17
Jan-18
Mar-18
May-18
Jul-18
Sep-18
Nov-18
Jan-19
Mar-19
May-19
Jul-19
Sep-19
Nov-19
Jan-20
Mar-20
May-20


Crystal River Unit 5
Maintenance Outage Rate
Monthly
12 Months Ending
Target
MOR
18.00
16.00
14.00
12.00
10.00
8.00
6.00
4.00
2.00
0.00
Jul-17
Sep-17
Nov-17
Jan-18
Mar-18
May-18
Jul-18
Sep-18
Nov-18
Jan-19
Mar-19
May-19
Jul-19
Sep-19
Nov-19
Jan-20
Mar-20
May-20


Crystal River Unit 5
Partial Forced Outage Rate
Monthly
12 Months Ending
Target
PFOR
35.00
30.00
25.00
20.00
15.00
10.00
5.00
0.00
Jul-17
Sep-17
Nov-17
Jan-18
Mar-18
May-18
Jul-18
Sep-18
Nov-18
Jan-19
Mar-19
May-19
Jul-19
Sep-19
Nov-19
Jan-20
Mar-20
May-20


Crystal River Unit 5
Partial Maintenance Outage Rate
Monthly
12 Months Ending
Target
PMOR
3.00
2.50
2.00
1.50
1.00
0.50
0.00
Jul-17
Sep-17
Nov-17
Jan-18
Mar-18
May-18
Jul-18
Sep-18
Nov-18
Jan-19
Mar-19
May-19
Jul-19
Sep-19
Nov-19
Jan-20
Mar-20
May-20


Crystal River Unit 5
Equivalent Unplanned Outage Rate
Monthly
12 Mon hs Ending
Target
EUOR
120.00
100.00
80.00
60.00
40.00
20.00
0.00
Jul-17
Sep-17
Nov-17
Jan-18
Mar-18
May-18
Jul-18
Sep-18
Nov-18
Jan-19
Mar-19
May-19
Jul-19
Sep-19
Nov-19
Jan-20
Mar-20
May-20


Crystal River Unit 5
Equivalent Unplanned Outage Factor
Monthly
12 Mon hs Ending
Target
EUOF
70.00
60.00
50.00
40.00
30.00
20.00
10.00
0.00
Jul-17
Sep-17
Nov-17
Jan-18
Mar-18
May-18
Jul-18
Sep-18
Nov-18
Jan-19
Mar-19
May-19
Jul-19
Sep-19
Nov-19
Jan-20
Mar-20
May-20

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Unit 1

	Jul-17	**Aug-17**	**Sep-17**	**Oct-17**	**Nov-17**	**Dec-17**	**Jan-18**	**Feb-18**	**Mar-18**	**Apr-18**	**May-18**	**Jun-18**	**Jul-18**	**Aug-18**	**Sep-18**	**Oct-18**	**Nov-18**	**Dec-18**
PER HOURS	744.00	744.00	720.00	744.00	721.00	744.00	744.00	672.00	743.00	720.00	744.00	720.00	744.00	744.00	720.00	744.00	721.00	744.00
SER HOURS	722.54	724.19	662.30	653.40	691.81	621.65	714.50	672.00	363.69	495.04	704.70	685.18	732.31	715.07	720.00	580.80	621.72	61.63
RSH	1.42	19.81	57.70	40.66	19.01	98.75	16.65	0.00	0.05	0.02	15.99	0.00	0.00	2.76	0.00	78.31	63.08	632.44
UH	20.04	0.00	0.00	49.95	10.17	23.60	12.85	0.00	379.26	224.94	23.31	34.82	11.69	26.18	0.00	84.88	36.20	49.93
POH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	359.88	224.94	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
FOH	20.04	0.00	0.00	3.90	10.17	23.60	12.85	0.00	19.38	0.00	10.84	34.82	0.00	7.36	0.00	3.45	36.20	0.00
MOH	0.00	0.00	0.00	46.05	0.00	0.00	0.00	0.00	0.00	0.00	12.47	0.00	11.69	18.82	0.00	81.44	0.00	49.93
PFOH	22.74	0.00	0.00	2.67	0.00	4.10	12.44	0.00	3.56	0.00	10.38	4.32	10.93	22.54	0.00	0.00	0.00	18.06
LRPF	108.05	0.00	0.00	77.98	0.00	99.00	69.78	0.00	76.57	0.00	67.60	69.07	51.62	61.35	0.00	0.00	0.00	73.61
EFOH	4.75	0.00	0.00	0.40	0.00	0.79	1.75	0.00	0.55	0.00	1.42	0.60	1.14	2.79	0.00	0.00	0.00	2.69
PMOH	0.00	0.00	0.00	0.00	4.85	17.06	0.00	0.00	0.00	0.00	11.86	0.00	0.00	0.00	0.00	0.00	0.00	0.00
LRPM	0.00	0.00	0.00	0.00	99.01	99.02	0.00	0.00	0.00	0.00	67.62	0.00	0.00	0.00	0.00	0.00	0.00	0.00
EMOH	0.00	0.00	0.00	0.00	0.93	3.27	0.00	0.00	0.00	0.00	1.62	0.00	0.00	0.00	0.00	0.00	0.00	0.00
NPC	517.00	517.00	517.00	517.00	517.00	517.00	495.00	495.00	495.00	495.00	495.00	495.00	495.00	495.00	495.00	495.00	495.00	495.00

MONTHLY	**Jul-17**	**Aug-17**	**Sep-17**	**Oct-17**	**Nov-17**	**Dec-17**	**Jan-18**	**Feb-18**	**Mar-18**	**Apr-18**	**May-18**	**Jun-18**	**Jul-18**	**Aug-18**	**Sep-18**	**Oct-18**	**Nov-18**	**Dec-18**
FOR	2.70	0.00	0.00	0.59	1.45	3.66	1.77	0.00	5.06	0.00	1.51	4.84	0.00	1.02	0.00	0.59	5.50	0.00
MOR	0.00	0.00	0.00	6.58	0.00	0.00	0.00	0.00	0.00	0.00	1.74	0.00	1.57	2.56	0.00	12.30	0.00	44.76
PFOR	0.66	0.00	0.00	0.06	0.00	0.13	0.25	0.00	0.15	0.00	0.20	0.09	0.16	0.39	0.00	0.00	0.00	4.36
PMOR	0.00	0.00	0.00	0.00	0.13	0.53	0.00	0.00	0.00	0.00	0.23	0.00	0.00	0.00	0.00	0.00	0.00	0.00
EUOR	3.34	0.00	0.00	7.16	1.58	4.29	2.01	0.00	5.20	0.00	3.62	4.92	1.72	3.91	0.00	12.75	5.50	47.16
EUOF	3.33	0.00	0.00	6.77	1.54	3.72	1.96	0.00	2.68	0.00	3.54	4.92	1.72	3.89	0.00	11.41	5.02	7.07
POF	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	48.44	31.24	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
EAF	96.67	100.00	100.00	93.23	98.46	96.28	98.04	100.00	48.88	68.76	96.46	95.08	98.28	96.11	100.00	88.59	94.98	92.93

12 MONTHS	**Jul-17**	**Aug-17**	**Sep-17**	**Oct-17**	**Nov-17**	**Dec-17**	**Jan-18**	**Feb-18**	**Mar-18**	**Apr-18**	**May-18**	**Jun-18**	**Jul-18**	**Aug-18**	**Sep-18**	**Oct-18**	**Nov-18**	**Dec-18**
FOR	1.72	1.72	1.74	1.81	1.94	2.25	2.38	2.38	2.76	2.62	2.29	1.73	1.47	1.57	1.56	1.57	1.91	1.74
MOR	0.36	0.36	0.36	0.74	0.74	0.62	0.61	0.61	0.64	0.61	0.76	0.75	0.90	1.14	1.13	1.59	1.61	2.41
PFOR	0.66	0.66	0.67	0.68	0.68	0.69	0.70	0.70	0.75	0.71	0.27	0.13	0.09	0.12	0.12	0.12	0.12	0.15
PMOR	0.00	0.00	0.00	0.00	0.01	0.06	0.06	0.06	0.06	0.06	0.08	0.08	0.08	0.08	0.07	0.08	0.06	0.02
EUOR	2.71	2.72	2.74	3.18	3.32	3.57	3.70	3.70	4.15	3.94	3.35	2.66	2.51	2.87	2.85	3.30	3.63	4.23
EUOF	2.37	2.37	2.37	2.74	2.87	3.08	3.25	3.25	3.48	3.48	3.02	2.40	2.26	2.59	2.59	2.99	3.27	3.56
POF	7.71	7.71	7.71	7.71	7.71	7.71	7.71	7.71	11.74	7.38	6.68	6.68	6.68	6.68	6.68	6.68	6.68	6.68
EAF	89.92	89.92	89.92	89.55	89.42	89.21	89.04	89.04	84.78	89.14	90.30	90.92	91.06	90.73	90.73	90.34	90.05	89.76

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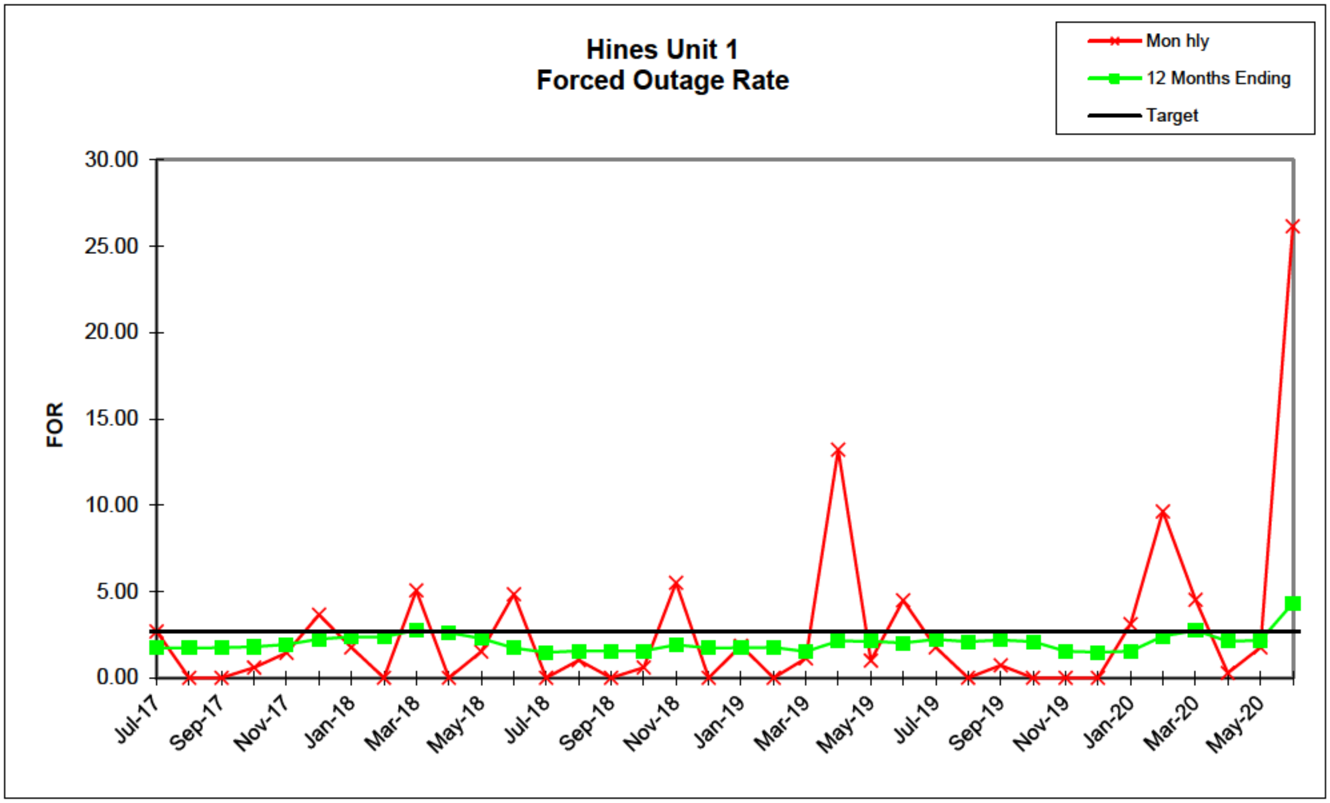
Unit 1

	Jan-19	Feb-19	Mar-19	Apr-19	May-19	Jun-19	Jul-19	Aug-19	Sep-19	Oct-19	Nov-19	Dec-19	Jan-20	Feb-20	Mar-20	Apr-20	May-20	Jun-20
PER HOURS	744.00	672.00	743.00	720.00	744.00	720.00	744.00	744.00	720.00	744.00	721.00	744.00	744.00	696.00	743.00	720.00	744.00	720.00
SER HOURS	356.18	588.34	669.00	259.95	562.87	555.81	705.57	744.00	676.25	726.62	721.00	264.97	259.00	575.22	654.59	573.34	632.06	531.58
RSH	25.73	17.44	66.37	28.53	5.00	138.05	25.81	0.00	38.81	17.38	0.00	479.03	476.68	42.26	57.41	24.00	64.25	0.00
UH	362.09	66.22	7.63	431.52	176.13	26.14	12.61	0.00	4.94	0.00	0.00	0.00	8.32	78.52	31.00	122.66	47.68	188.42
POH	0.00	0.00	0.00	391.94	158.63	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
FOH	6.74	0.00	7.63	39.58	5.75	26.14	12.61	0.00	4.94	0.00	0.00	0.00	8.32	61.38	31.00	1.66	11.41	188.42
MOH	355.35	66.22	0.00	0.00	11.76	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	17.14	0.00	121.00	36.27	0.00
PFOH	166.45	12.02	7.32	26.28	5.36	69.26	12.33	0.00	0.00	0.00	4.03	0.00	0.00	16.58	5.00	2.09	0.00	0.00
LRPF	82.00	82.02	85.08	78.36	51.29	42.41	8.00	0.00	0.00	0.00	74.52	0.00	0.00	77.00	49.54	82.02	0.00	0.00
EFOH	27.85	2.01	1.27	4.20	0.56	6.00	0.20	0.00	0.00	0.00	0.61	0.00	0.00	2.61	0.51	0.35	0.00	0.00
PMOH	0.00	0.00	0.00	2.66	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
LRPM	0.00	0.00	0.00	78.11	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
EMOH	0.00	0.00	0.00	0.42	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
NPC	490.00	490.00	490.00	490.00	490.00	490.00	490.00	490.00	490.00	490.00	490.00	490.00	490.00	490.00	490.00	490.00	490.00	490.00

MONTHLY	**Jan-19**	**Feb-19**	**Mar-19**	**Apr-19**	**May-19**	**Jun-19**	**Jul-19**	**Aug-19**	**Sep-19**	**Oct-19**	**Nov-19**	**Dec-19**	**Jan-20**	**Feb-20**	**Mar-20**	**Apr-20**	**May-20**	**Jun-20**
FOR	1.86	0.00	1.13	13.21	1.01	4.49	1.76	0.00	0.73	0.00	0.00	0.00	3.11	9.64	4.52	0.29	1.77	26.17
MOR	49.94	10.12	0.00	0.00	2.05	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	2.89	0.00	17.43	5.43	0.00
PFOR	7.82	0.34	0.19	1.62	0.10	1.08	0.03	0.00	0.00	0.00	0.09	0.00	0.00	0.45	0.08	0.06	0.00	0.00
PMOR	0.00	0.00	0.00	0.16	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
EUOR	54.29	10.42	1.32	14.76	3.11	5.52	1.78	0.00	0.73	0.00	0.09	0.00	3.11	12.41	4.60	17.67	7.01	26.17
EUOF	52.41	10.15	1.20	6.14	2.43	4.46	1.72	0.00	0.69	0.00	0.09	0.00	1.12	11.66	4.24	17.08	6.41	26.17
POF	0.00	0.00	0.00	54.44	21.32	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
EAF	47.59	89.85	98.80	39.42	76.25	95.54	98.28	100.00	99.31	100.00	99.91	100.00	98.88	88.34	95.76	82.92	93.59	73.83

12 MONTHS	**Jan-19**	**Feb-19**	**Mar-19**	**Apr-19**	**May-19**	**Jun-19**	**Jul-19**	**Aug-19**	**Sep-19**	**Oct-19**	**Nov-19**	**Dec-19**	**Jan-20**	**Feb-20**	**Mar-20**	**Apr-20**	**May-20**	**Jun-20**
FOR	1.74	1.76	1.52	2.14	2.11	2.03	2.22	2.10	2.19	2.09	1.54	1.49	1.54	2.42	2.75	2.12	2.17	4.33
MOR	7.32	8.25	7.92	8.17	8.33	8.48	8.36	8.08	8.13	6.89	6.80	5.97	1.14	0.43	0.43	2.09	2.40	2.41
PFOR	0.55	0.59	0.57	0.66	0.66	0.76	0.74	0.70	0.70	0.69	0.68	0.63	0.22	0.23	0.22	0.15	0.14	0.06
PMOR	0.02	0.02	0.02	0.03	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.00	0.00	0.00
EUOR	9.34	10.29	9.75	10.60	10.70	10.86	10.90	10.49	10.62	9.34	8.77	7.87	2.87	3.05	3.38	4.27	4.61	6.59
EUOF	7.84	8.62	8.50	9.00	8.91	8.87	8.87	8.54	8.60	7.63	7.22	6.62	2.26	2.40	2.66	3.56	3.90	5.67
POF	6.68	6.68	2.57	4.47	6.29	6.29	6.29	6.29	6.29	6.29	6.29	6.29	6.29	6.27	6.27	1.81	0.00	0.00
EAF	85.48	84.70	88.93	86.52	84.81	84.85	84.85	85.18	85.12	86.09	86.49	87.10	91.45	91.33	91.07	94.64	96.10	94.33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Forced Outage Rate
Mon hly
12 Months Ending
Target
FOR
30.00
25.00
20.00
15.00
10.00
5.00
0.00
Jul-17
Sep-17
Nov-17
Jan-18
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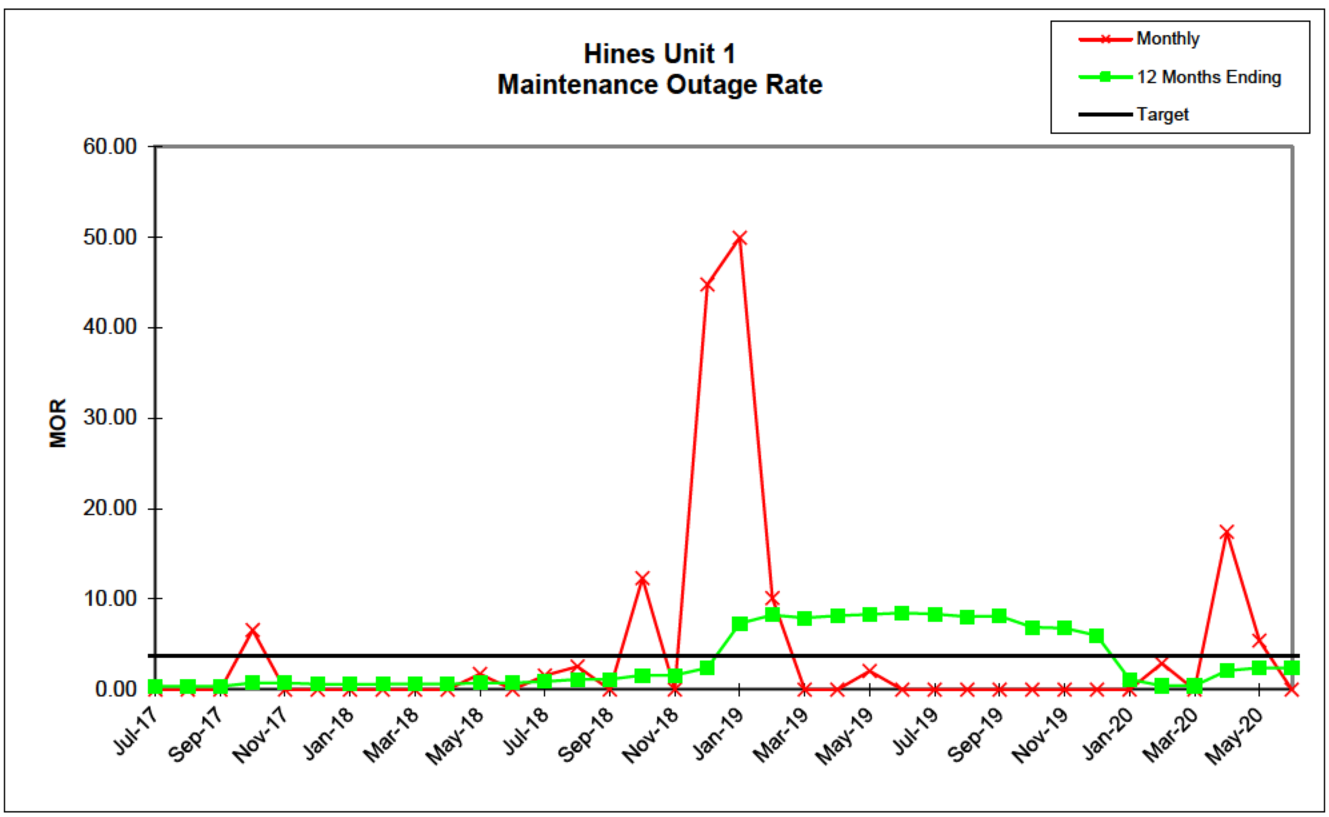
May-20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Maintenance Outage Rate
Monthly
12 Months Ending
Target
MOR
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50.00
40.00
30.00
20.00
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Jul-17
Sep-17
Nov-17
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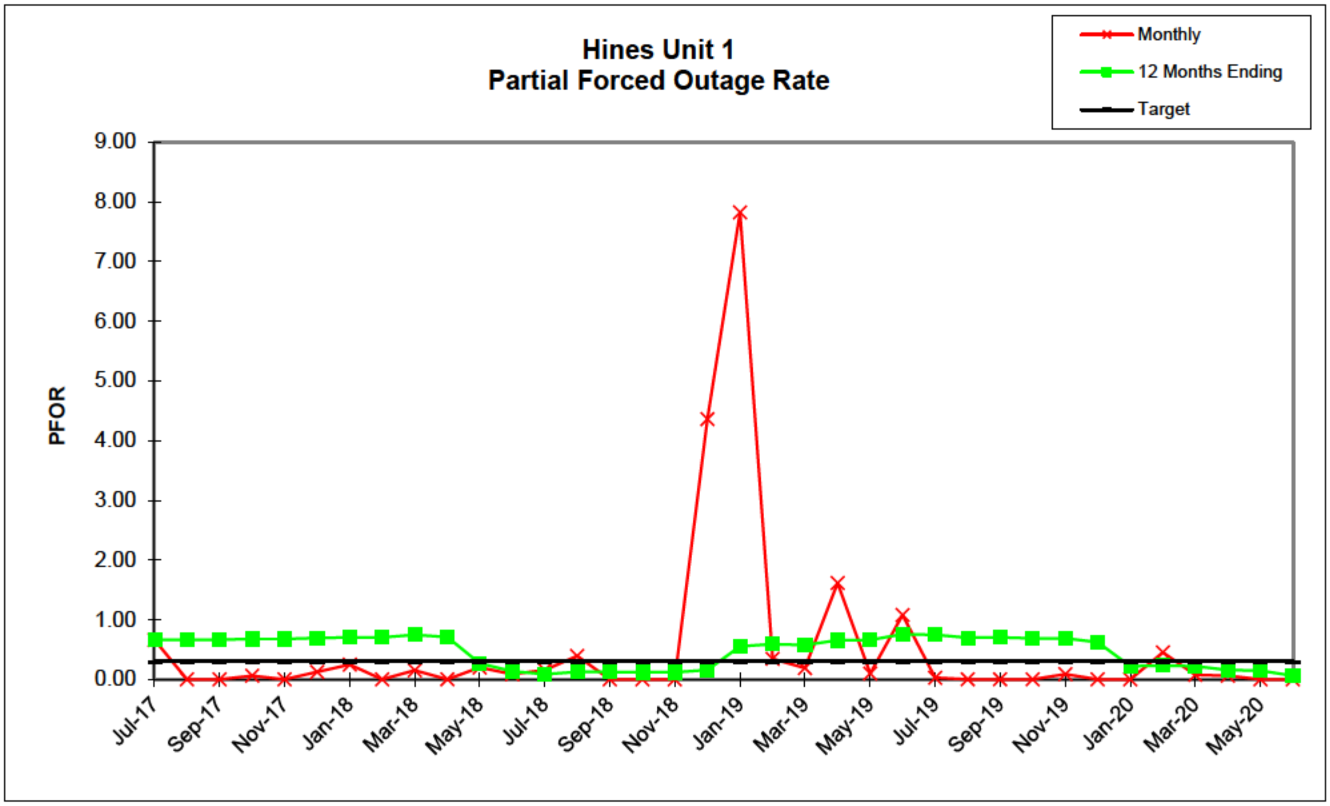
Mar-20
May-20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Monthly
12 Months Ending
Target
PFOR
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8.00
7.00
6.00
5.00
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3.00
2.00
1.00
0.00
Jul-17
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Nov-17
Jan-18
Mar-18
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Jul-18
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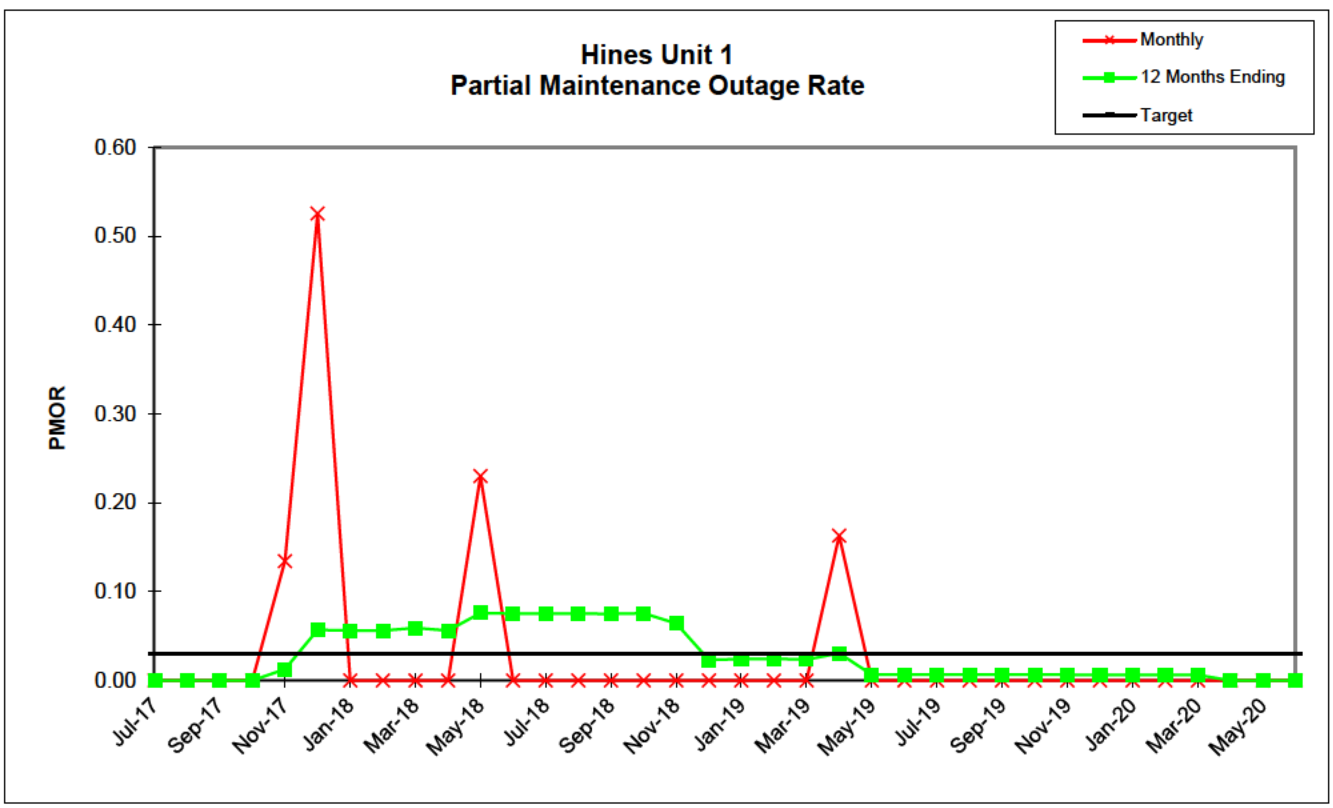
Mar-20
May-20


Hines Unit 1
Partial Maintenance Outage Rate
Monthly
12 Months Ending
Target
PMOR
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0.50
0.40
0.30
0.20
0.10
0.00
Jul-17
Sep-17
Nov-17
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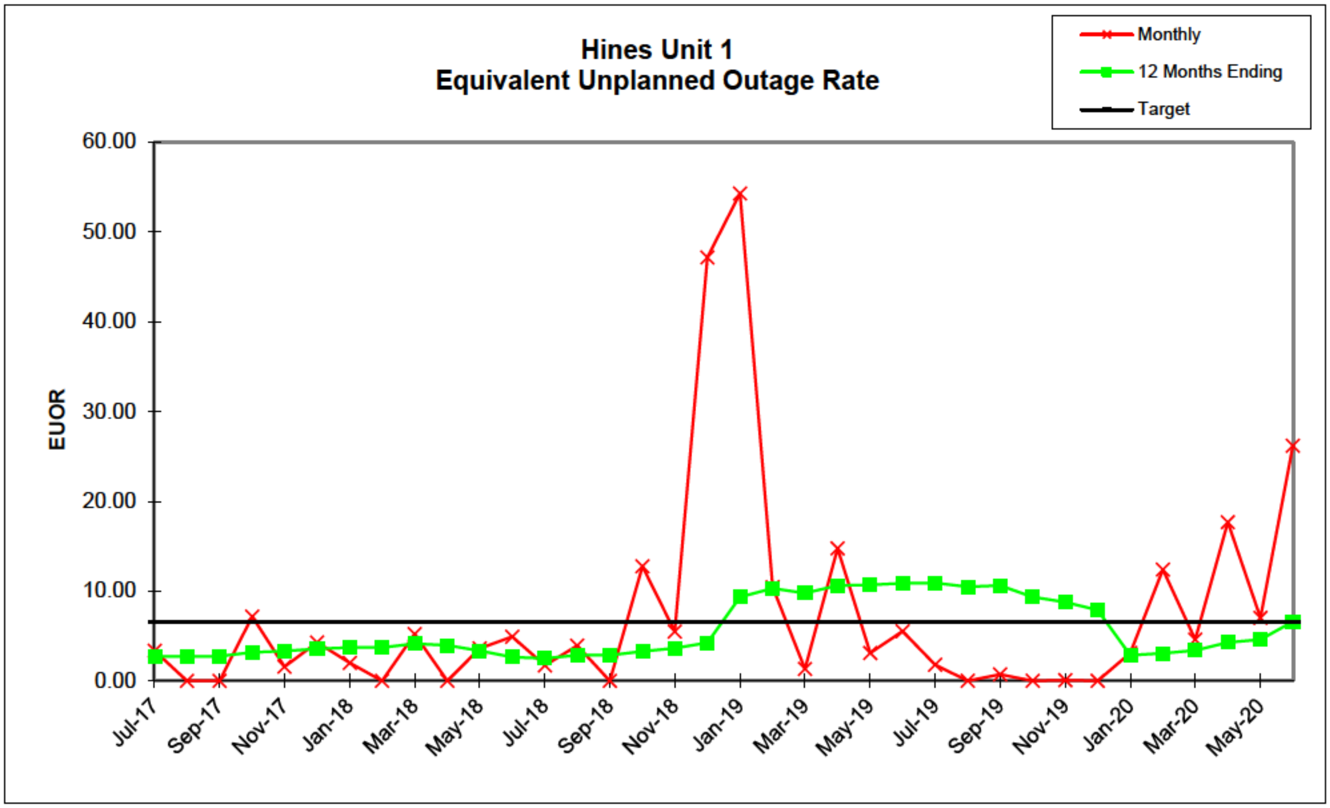
Mar-20
May-20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Equivalent Unplanned Outage Rate
Monthly
12 Months Ending
Target
EUOR
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50.00
40.00
30.00
20.00
10.00
0.00
Jul-17
Sep-17
Nov-17
Jan-18
Mar-18
May-18
Jul-18
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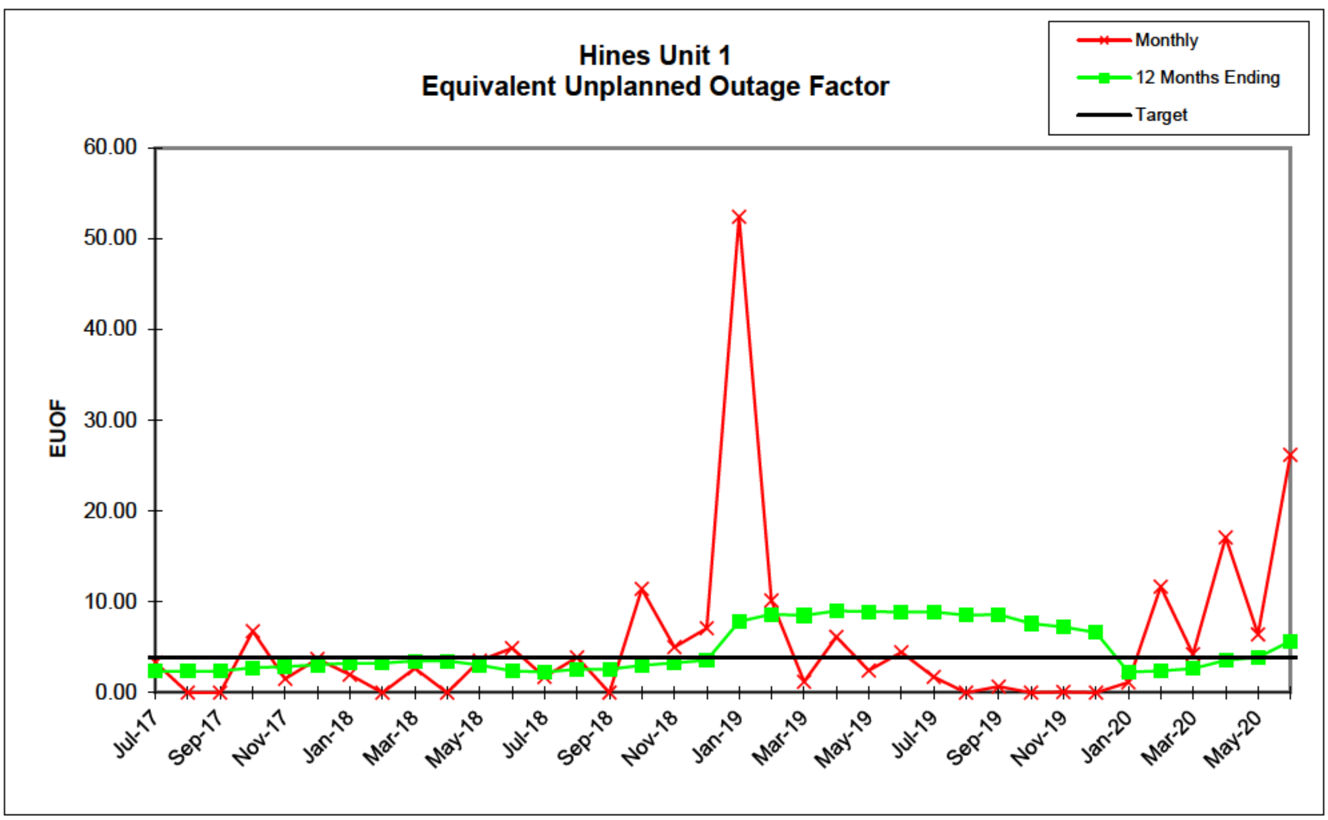
Mar-20
May-20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Equivalent Unplanned Outage Factor
Monthly
12 Months Ending
Target
EUOF
60.00
50.00
40.00
30.00
20.00
10.00
0.00
Jul-17
Sep-17
Nov-17
Jan-18
Mar-18
May-18
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May-19
Jul-19
Sep-19
Nov-19
Jan-20
Mar-20
May-20

Hines
Unit 2

	Jul-17	Aug-17	Sep-17	Oct-17	Nov-17	Dec-17	Jan-18	Feb-18	Mar-18	Apr-18	May-18	Jun-18	Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18
PER HOURS	744.00	744.00	720.00	744.00	721.00	744.00	744.00	672.00	743.00	720.00	744.00	720.00	744.00	744.00	720.00	744.00	721.00	744.00
SER HOURS	738.76	719.49	507.02	148.41	654.39	487.29	693.32	464.52	669.67	313.00	703.73	720.00	742.21	741.04	720.00	712.89	625.29	285.04
RSH	0.00	0.00	14.89	95.14	58.38	256.71	50.68	204.00	2.22	0.01	0.59	0.00	0.00	0.00	0.00	31.11	73.62	438.84
UH	5.24	24.51	198.09	500.45	8.23	0.00	0.00	3.48	71.10	406.99	39.68	0.00	1.79	2.96	0.00	0.00	22.09	20.13
POH	0.00	0.00	193.92	500.45	0.00	0.00	0.00	0.00	0.00	406.99	33.66	0.00	0.00	0.00	0.00	0.00	0.00	0.00
FOH	0.00	24.51	4.17	0.00	8.23	0.00	0.00	3.48	71.10	0.00	6.02	0.00	1.79	0.00	0.00	0.00	0.00	20.13
MOH	5.24	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	2.96	0.00	0.00	22.09	0.00
PFOH	0.00	28.96	9.20	0.00	9.13	0.00	0.00	3.42	0.00	0.00	6.20	0.00	1.76	0.00	0.00	0.00	0.00	0.00
LRPF	0.00	132.44	133.33	0.00	117.43	0.00	0.00	92.32	0.00	0.00	90.96	0.00	86.19	0.00	0.00	0.00	0.00	0.00
EFOH	0.00	7.04	2.25	0.00	1.97	0.00	0.00	0.60	0.00	0.00	1.07	0.00	0.29	0.00	0.00	0.00	0.00	0.00
PMOH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	2.91	0.00	0.00	22.76	0.00
LRPM	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	94.40	0.00	0.00	80.33	0.00
EMOH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.52	0.00	0.00	3.47	0.00
NPC	545.00	545.00	545.00	545.00	545.00	545.00	527.00	527.00	527.00	527.00	527.00	527.00	527.00	527.00	527.00	527.00	527.00	527.00

MONTHLY	**Jul-17**	**Aug-17**	**Sep-17**	**Oct-17**	**Nov-17**	**Dec-17**	**Jan-18**	**Feb-18**	**Mar-18**	**Apr-18**	**May-18**	**Jun-18**	**Jul-18**	**Aug-18**	**Sep-18**	**Oct-18**	**Nov-18**	**Dec-18**
FOR	0.00	3.29	0.82	0.00	1.24	0.00	0.00	0.74	9.60	0.00	0.85	0.00	0.24	0.00	0.00	0.00	0.00	6.60
MOR	0.70	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.40	0.00	0.00	3.41	0.00
PFOR	0.00	0.98	0.44	0.00	0.30	0.00	0.00	0.13	0.00	0.00	0.15	0.00	0.04	0.00	0.00	0.00	0.00	0.00
PMOR	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.07	0.00	0.00	0.55	0.00
EUOR	0.70	4.24	1.26	0.00	1.54	0.00	0.00	0.87	9.60	0.00	1.00	0.00	0.28	0.47	0.00	0.00	3.95	6.60
EUOF	0.70	4.24	0.89	0.00	1.41	0.00	0.00	0.61	9.57	0.00	0.95	0.00	0.28	0.47	0.00	0.00	3.54	2.71
POF	0.00	0.00	26.93	67.26	0.00	0.00	0.00	0.00	0.00	56.53	4.52	0.00	0.00	0.00	0.00	0.00	0.00	0.00
EAF	99.30	95.76	72.17	32.74	98.59	100.00	100.00	99.39	90.43	43.47	94.52	100.00	99.72	99.53	100.00	100.00	96.46	97.29

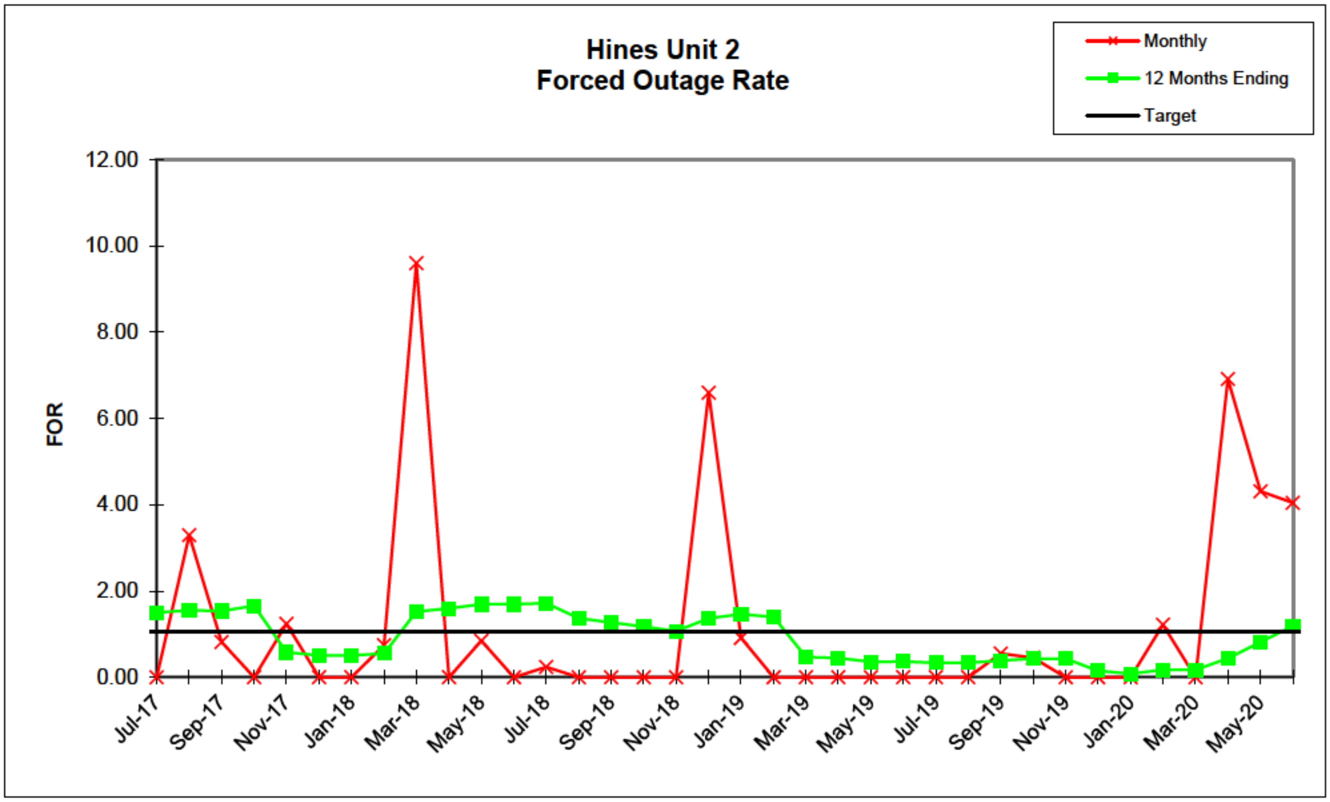
12 MONTHS	**Jul-17**	**Aug-17**	**Sep-17**	**Oct-17**	**Nov-17**	**Dec-17**	**Jan-18**	**Feb-18**	**Mar-18**	**Apr-18**	**May-18**	**Jun-18**	**Jul-18**	**Aug-18**	**Sep-18**	**Oct-18**	**Nov-18**	**Dec-18**
FOR	1.50	1.55	1.54	1.66	0.58	0.51	0.51	0.55	1.52	1.60	1.69	1.69	1.72	1.37	1.27	1.17	1.07	1.37
MOR	1.97	0.47	0.15	0.07	0.07	0.07	0.07	0.07	0.07	0.08	0.08	0.08	0.00	0.04	0.04	0.04	0.33	0.34
PFOR	0.31	0.39	0.42	0.46	0.17	0.16	0.16	0.16	0.16	0.17	0.19	0.19	0.19	0.09	0.06	0.05	0.03	0.03
PMOR	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.05	0.05
EUOR	3.71	2.39	2.09	2.18	0.83	0.74	0.73	0.78	1.75	1.84	1.95	1.95	1.91	1.50	1.37	1.27	1.47	1.78
EUOF	3.44	2.22	1.90	1.83	0.69	0.61	0.61	0.66	1.47	1.47	1.55	1.55	1.51	1.19	1.12	1.12	1.29	1.52
POF	0.00	0.00	2.21	7.93	7.93	7.93	7.93	7.93	7.93	12.57	12.96	12.96	12.96	12.96	10.74	5.03	5.03	5.03
EAF	96.56	97.78	95.89	90.25	91.38	91.46	91.46	91.42	90.61	85.96	85.49	85.49	85.53	85.85	88.14	93.85	93.68	93.45

Hines
Unit 2

	Jan-19	Feb-19	Mar-19	Apr-19	May-19	Jun-19	Jul-19	Aug-19	Sep-19	Oct-19	Nov-19	Dec-19	Jan-20	Feb-20	Mar-20	Apr-20	May-20	Jun-20
PER HOURS	744.00	672.00	743.00	720.00	744.00	720.00	744.00	744.00	720.00	744.00	721.00	744.00	744.00	696.00	743.00	720.00	744.00	720.00
SER HOURS	522.14	594.16	262.42	703.77	741.59	693.36	743.00	738.04	651.29	669.50	721.00	744.00	703.55	559.17	0.00	246.44	578.69	623.31
RSH	217.02	77.84	142.29	16.23	2.41	26.64	1.00	5.96	64.44	71.44	0.00	0.00	40.45	98.96	0.00	12.92	40.18	17.21
UH	4.84	0.00	338.28	0.00	0.00	0.00	0.00	0.00	4.27	3.06	0.00	0.00	0.00	37.87	743.00	460.64	125.13	79.48
POH	0.00	0.00	331.28	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	24.16	743.00	442.32	0.00	0.00
FOH	4.84	0.00	0.00	0.00	0.00	0.00	0.00	0.00	3.61	3.06	0.00	0.00	0.00	6.90	0.00	18.32	26.09	26.27
MOH	0.00	0.00	7.00	0.00	0.00	0.00	0.00	0.00	0.66	0.00	0.00	0.00	0.00	6.81	0.00	0.00	99.04	53.21
PFOH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	165.08	41.68	91.09
LRPF	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	150.15	120.10	94.72
EFOH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	47.30	9.55	16.47
PMOH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.39	0.00	0.00
LRPM	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	65.07	0.00	0.00
EMOH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.17	0.00	0.00
NPC	512.00	512.00	512.00	512.00	512.00	512.00	512.00	512.00	512.00	512.00	512.00	512.00	524.00	524.00	524.00	524.00	524.00	524.00

MONTHLY	**Jan-19**	**Feb-19**	**Mar-19**	**Apr-19**	**May-19**	**Jun-19**	**Jul-19**	**Aug-19**	**Sep-19**	**Oct-19**	**Nov-19**	**Dec-19**	**Jan-20**	**Feb-20**	**Mar-20**	**Apr-20**	**May-20**	**Jun-20**
FOR	0.92	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.55	0.45	0.00	0.00	0.00	1.22	0.00	6.92	4.31	4.04
MOR	0.00	0.00	2.60	0.00	0.00	0.00	0.00	0.00	0.10	0.00	0.00	0.00	0.00	1.20	0.00	0.00	14.61	7.87
PFOR	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	19.19	1.65	2.64
PMOR	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.07	0.00	0.00
EUOR	0.92	0.00	2.60	0.00	0.00	0.00	0.00	0.00	0.65	0.45	0.00	0.00	0.00	2.39	0.00	24.85	19.14	13.65
EUOF	0.65	0.00	0.94	0.00	0.00	0.00	0.00	0.00	0.59	0.41	0.00	0.00	0.00	1.97	0.00	9.14	18.10	13.33
POF	0.00	0.00	44.59	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	3.47	100.00	61.43	0.00	0.00
EAF	99.35	100.00	54.47	100.00	100.00	100.00	100.00	100.00	99.41	99.59	100.00	100.00	100.00	94.56	0.00	29.43	81.90	86.67

12 MONTHS	**Jan-19**	**Feb-19**	**Mar-19**	**Apr-19**	**May-19**	**Jun-19**	**Jul-19**	**Aug-19**	**Sep-19**	**Oct-19**	**Nov-19**	**Dec-19**	**Jan-20**	**Feb-20**	**Mar-20**	**Apr-20**	**May-20**	**Jun-20**
FOR	1.47	1.39	0.47	0.45	0.36	0.36	0.34	0.34	0.39	0.44	0.43	0.15	0.08	0.17	0.18	0.44	0.82	1.19
MOR	0.35	0.34	0.46	0.44	0.43	0.43	0.43	0.39	0.41	0.41	0.10	0.10	0.10	0.18	0.10	0.10	1.49	2.24
PFOR	0.03	0.02	0.02	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.66	0.81	1.05
PMOR	0.06	0.05	0.06	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
EUOR	1.88	1.80	1.00	0.95	0.85	0.85	0.82	0.78	0.84	0.89	0.53	0.25	0.18	0.35	0.27	1.20	3.07	4.40
EUOF	1.58	1.53	0.80	0.80	0.72	0.72	0.70	0.66	0.71	0.74	0.45	0.22	0.16	0.32	0.24	0.99	2.52	3.61
POF	5.03	5.03	8.81	4.17	3.78	3.78	3.78	3.78	3.78	3.78	3.78	3.78	3.78	4.05	8.73	13.77	13.77	13.77
EAF	93.39	93.44	90.39	95.03	95.50	95.50	95.52	95.56	95.51	95.48	95.77	96.00	96.05	95.63	91.03	85.24	83.71	82.62


Hines Unit 2
Forced Outage Rate
Monthly
12 Months Ending
Target
FOR
12.00
10.00
8.00
6.00
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0.00
Jul-17
Sep-17
Nov-17
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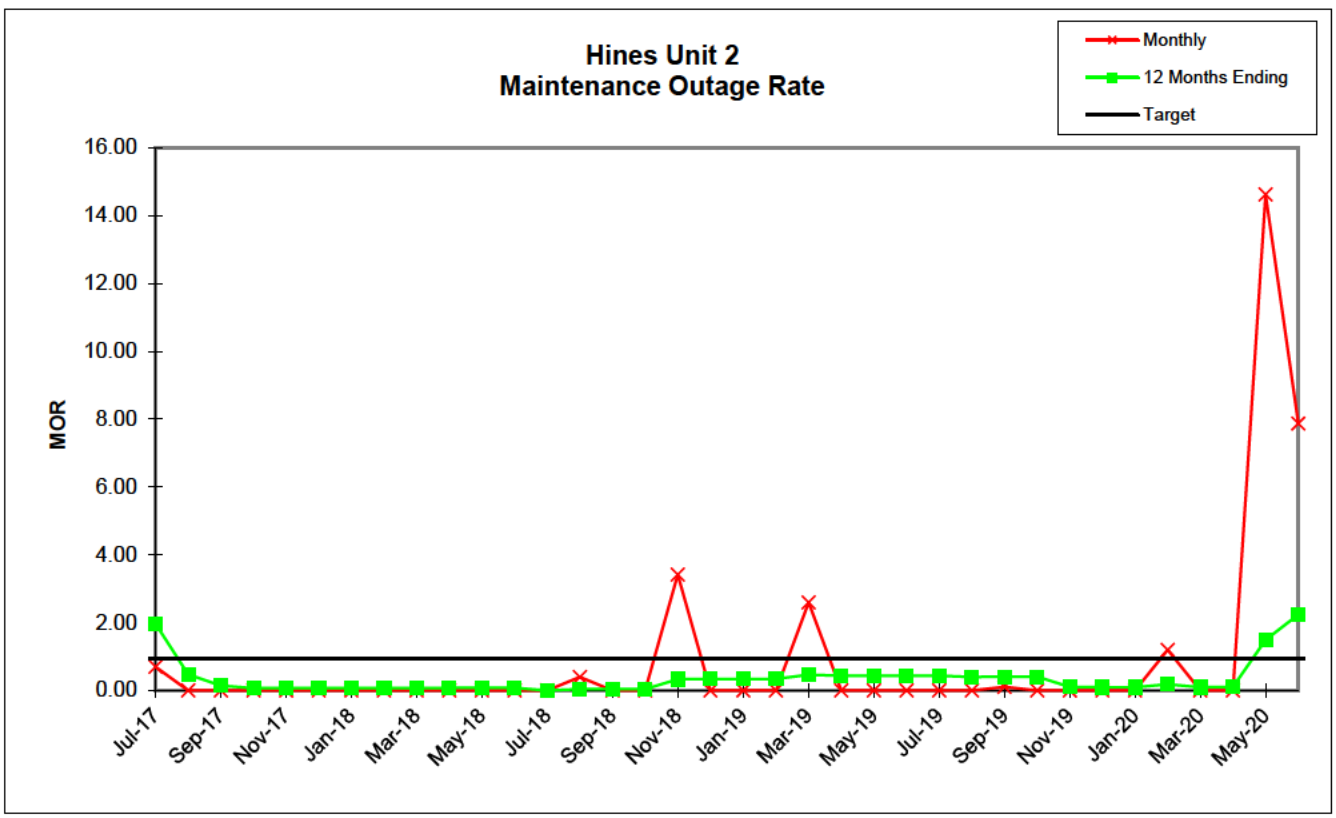
Hines Unit 2
Maintenance Outage Rate
Monthly
12 Months Ending
Target
MOR
16.00
14.00
12.00
10.00
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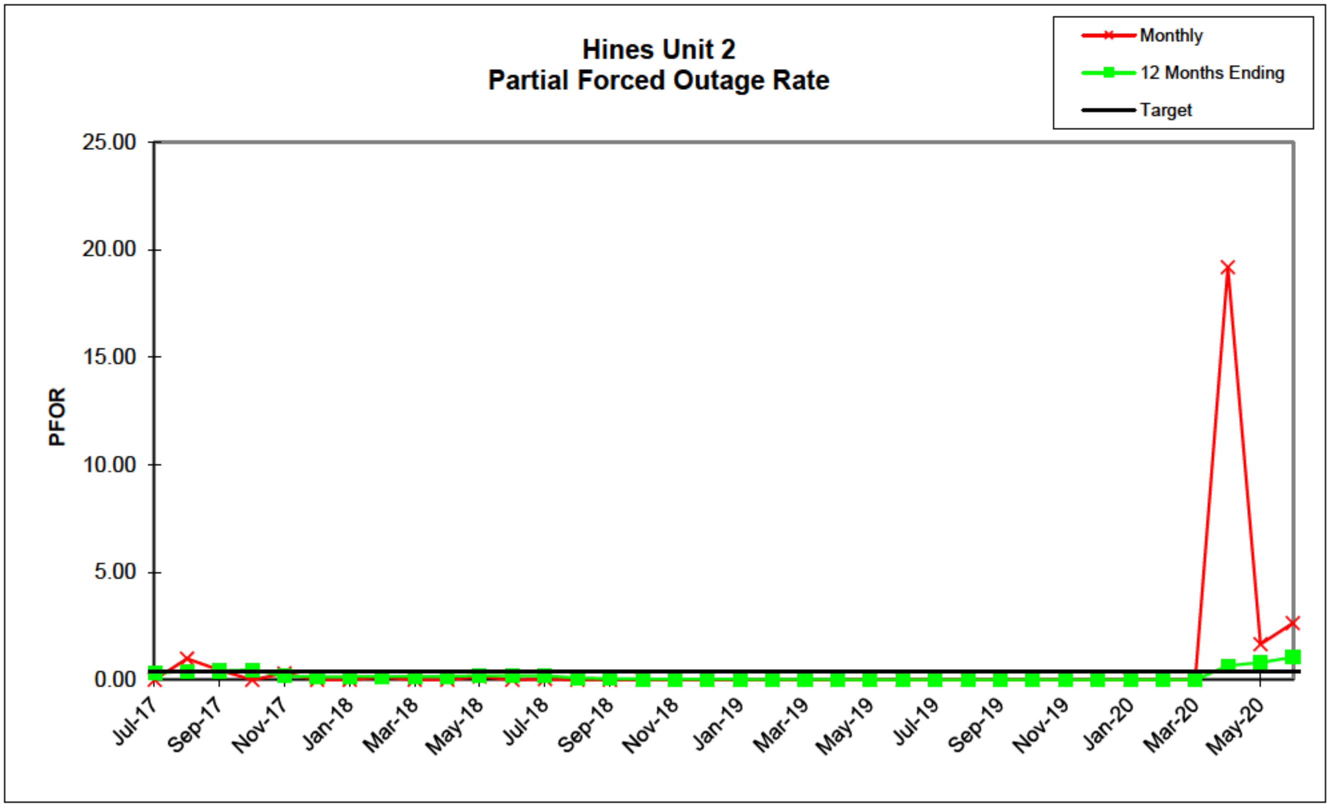
Mar-20
May-20


Hines Unit 2
Partial Forced Outage Rate
Monthly
12 Months Ending
Target
PFOR
25.00
20.00
15.00
10.00
5.00
0.00
Jul-17
Sep-17
Nov-17
Jan-18
Mar-18
May-18
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Nov-18
Jan-19
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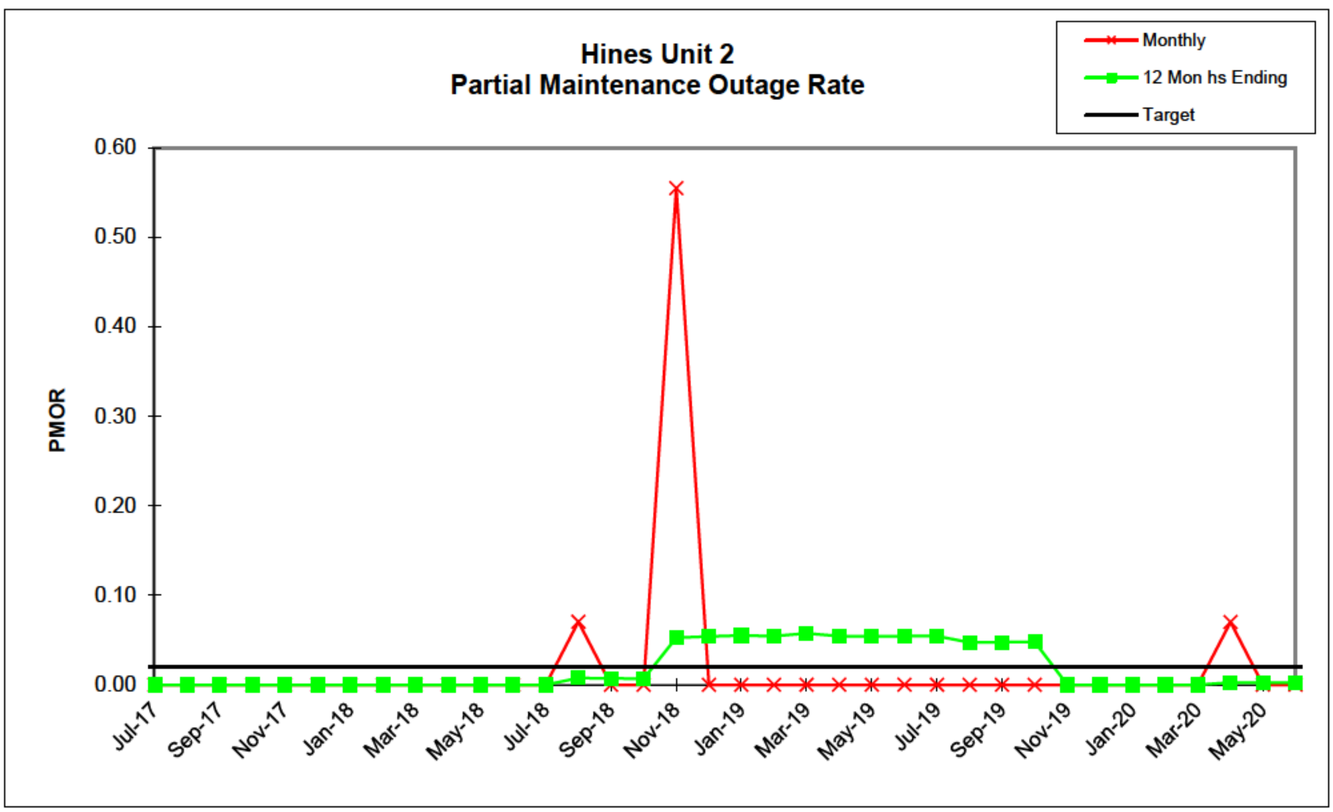
May-19
Jul-19
Sep-19
Nov-19
Jan-20
Mar-20
May-20


Hines Unit 2
Partial Maintenance Outage Rate
Monthly
12 Mon hs Ending
Target
PMOR
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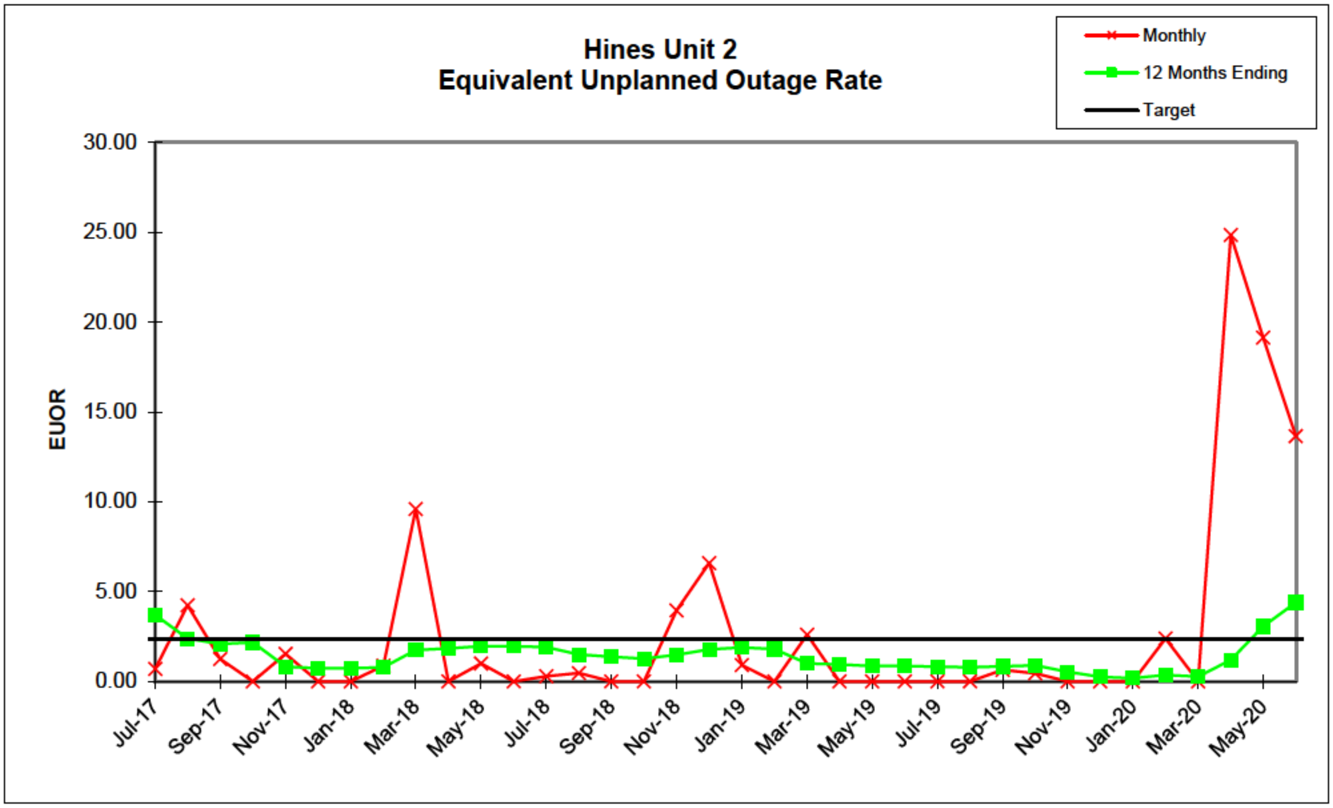
0.50
0.40
0.30
0.20
0.10
0.00
Jul-17
Sep-17
Nov-17
Jan-18
Mar-18
May-18
Jul-18
Sep-18
Nov-18
Jan-19
Mar-19
May-19
Jul-19
Sep-19
Nov-19
Jan-20
Mar-20
May-20


Hines Unit 2
Equivalent Unplanned Outage Rate
Monthly
12 Months Ending
Target
EUOR
30.00
25.00
20.00
15.00
10.00
5.00
0.00
Jul-17
Sep-17
Nov-17
Jan-18
Mar-18
May-18
Jul-18
Sep-18
Nov-18
Jan-19
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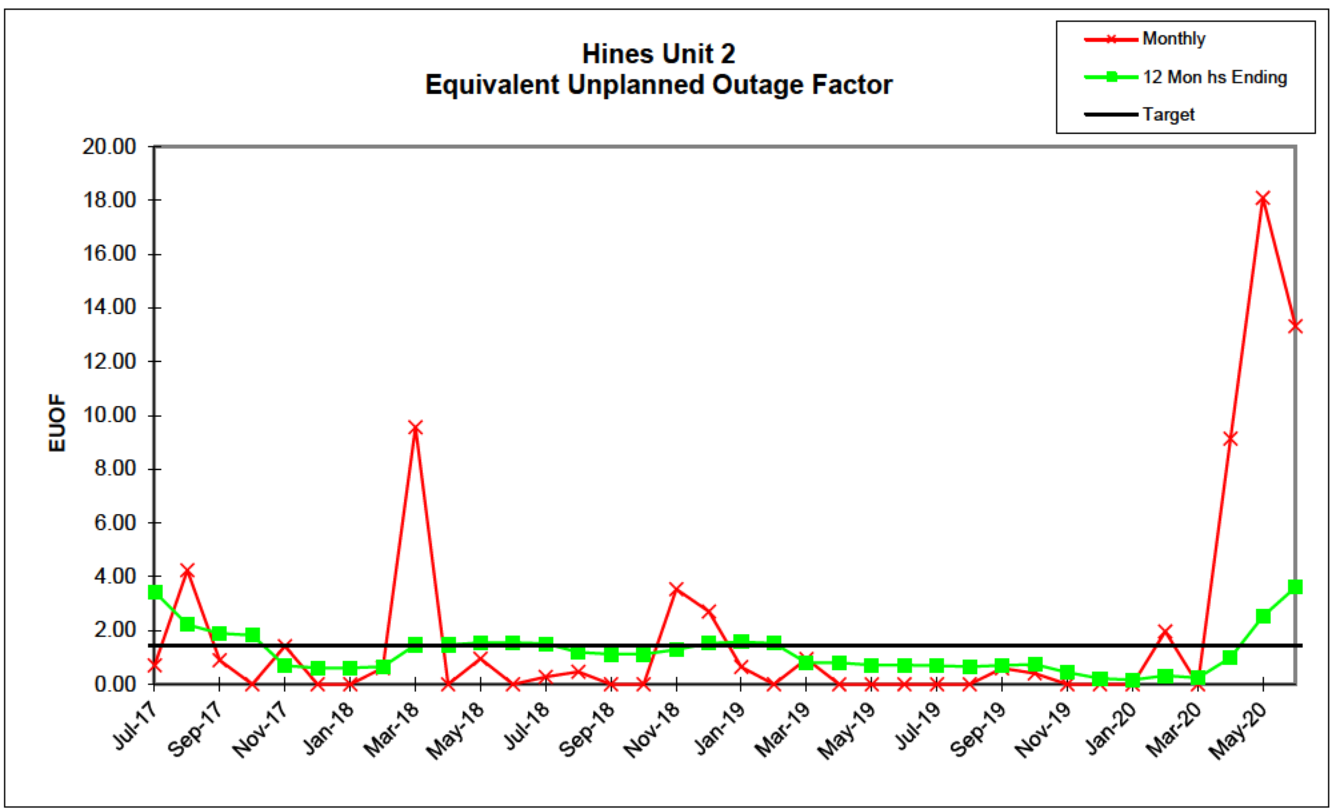
Jul-19
Sep-19
Nov-19
Jan-20
Mar-20
May-20


Hines Unit 2
Equivalent Unplanned Outage Factor
Monthly
12 Mon hs Ending
Target
EUOF
20.00
18.00
16.00
14.00
12.00
10.00
8.00
6.00
4.00
2.00
0.00
Jul-17
Sep-17
Nov-17
Jan-18
Mar-18
May-18
Jul-18
Sep-18
Nov-18
Jan-19
Mar-19
May-19
Jul-19
Sep-19
Nov-19
Jan-20
Mar-20
May-20

Hines
Unit 3

	Jul-17	Aug-17	Sep-17	Oct-17	Nov-17	Dec-17	Jan-18	Feb-18	Mar-18	Apr-18	May-18	Jun-18	Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18
PER HOURS	744.00	744.00	720.00	744.00	721.00	744.00	744.00	672.00	743.00	720.00	744.00	720.00	744.00	744.00	720.00	744.00	721.00	744.00
SER HOURS	701.00	744.00	548.72	744.00	597.58	732.16	478.31	413.24	598.18	705.76	710.57	720.00	731.95	739.49	673.52	39.01	605.99	706.70
RSH	0.00	0.00	0.00	0.00	88.09	0.17	262.50	256.47	135.86	1.44	11.55	0.00	0.00	0.00	0.00	0.00	113.58	37.30
UH	43.00	0.00	171.28	0.00	35.33	11.66	3.18	2.28	8.96	12.80	21.89	0.00	12.05	4.51	46.48	704.99	1.43	0.00
POH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	46.48	704.77	1.43	0.00
FOH	0.00	0.00	171.28	0.00	5.37	11.66	3.18	2.28	0.84	0.00	0.00	0.00	0.00	4.51	0.00	0.22	0.00	0.00
MOH	43.00	0.00	0.00	0.00	29.95	0.00	0.00	0.00	8.11	12.80	21.89	0.00	12.05	0.00	0.00	0.00	0.00	0.00
PFOH	0.00	0.00	137.97	0.00	0.00	6.22	2.94	1.11	0.98	0.00	39.40	0.00	0.00	4.40	0.00	0.00	0.00	0.00
LRPF	0.00	0.00	111.06	0.00	0.00	112.04	81.03	80.98	81.33	0.00	64.74	0.00	0.00	86.01	0.00	0.00	0.00	0.00
EFOH	0.00	0.00	28.22	0.00	0.00	1.28	0.46	0.17	0.15	0.00	4.90	0.00	0.00	0.73	0.00	0.00	0.00	0.00
PMOH	0.00	0.00	0.00	0.00	19.34	0.00	0.00	0.00	7.93	12.50	9.07	0.00	11.77	0.00	0.00	0.00	0.00	0.00
LRPM	0.00	0.00	0.00	0.00	108.08	0.00	0.00	0.00	82.96	81.65	83.99	0.00	87.00	0.00	0.00	0.00	0.00	0.00
EMOH	0.00	0.00	0.00	0.00	3.85	0.00	0.00	0.00	1.26	1.96	1.46	0.00	1.97	0.00	0.00	0.00	0.00	0.00
NPC	543.00	543.00	543.00	543.00	543.00	543.00	521.00	521.00	521.00	521.00	521.00	521.00	521.00	521.00	521.00	521.00	521.00	521.00

MONTHLY	**Jul-17**	**Aug-17**	**Sep-17**	**Oct-17**	**Nov-17**	**Dec-17**	**Jan-18**	**Feb-18**	**Mar-18**	**Apr-18**	**May-18**	**Jun-18**	**Jul-18**	**Aug-18**	**Sep-18**	**Oct-18**	**Nov-18**	**Dec-18**
FOR	0.00	0.00	23.79	0.00	0.89	1.57	0.66	0.55	0.14	0.00	0.00	0.00	0.00	0.61	0.00	0.56	0.00	0.00
MOR	5.78	0.00	0.00	0.00	4.77	0.00	0.00	0.00	1.34	1.78	2.99	0.00	1.62	0.00	0.00	0.00	0.00	0.00
PFOR	0.00	0.00	5.14	0.00	0.00	0.18	0.10	0.04	0.03	0.00	0.69	0.00	0.00	0.10	0.00	0.00	0.00	0.00
PMOR	0.00	0.00	0.00	0.00	0.64	0.00	0.00	0.00	0.21	0.28	0.21	0.00	0.27	0.00	0.00	0.00	0.00	0.00
EUOR	5.78	0.00	27.71	0.00	6.19	1.74	0.76	0.59	1.71	2.05	3.86	0.00	1.88	0.70	0.00	0.56	0.00	0.00
EUOF	5.78	0.00	27.71	0.00	5.43	1.74	0.49	0.36	1.40	2.05	3.80	0.00	1.88	0.70	0.00	0.03	0.00	0.00
POF	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	6.46	94.73	0.20	0.00
EAF	94.22	100.00	72.29	100.00	94.57	98.26	99.51	99.64	98.60	97.95	96.20	100.00	98.12	99.30	93.54	5.24	99.80	100.00

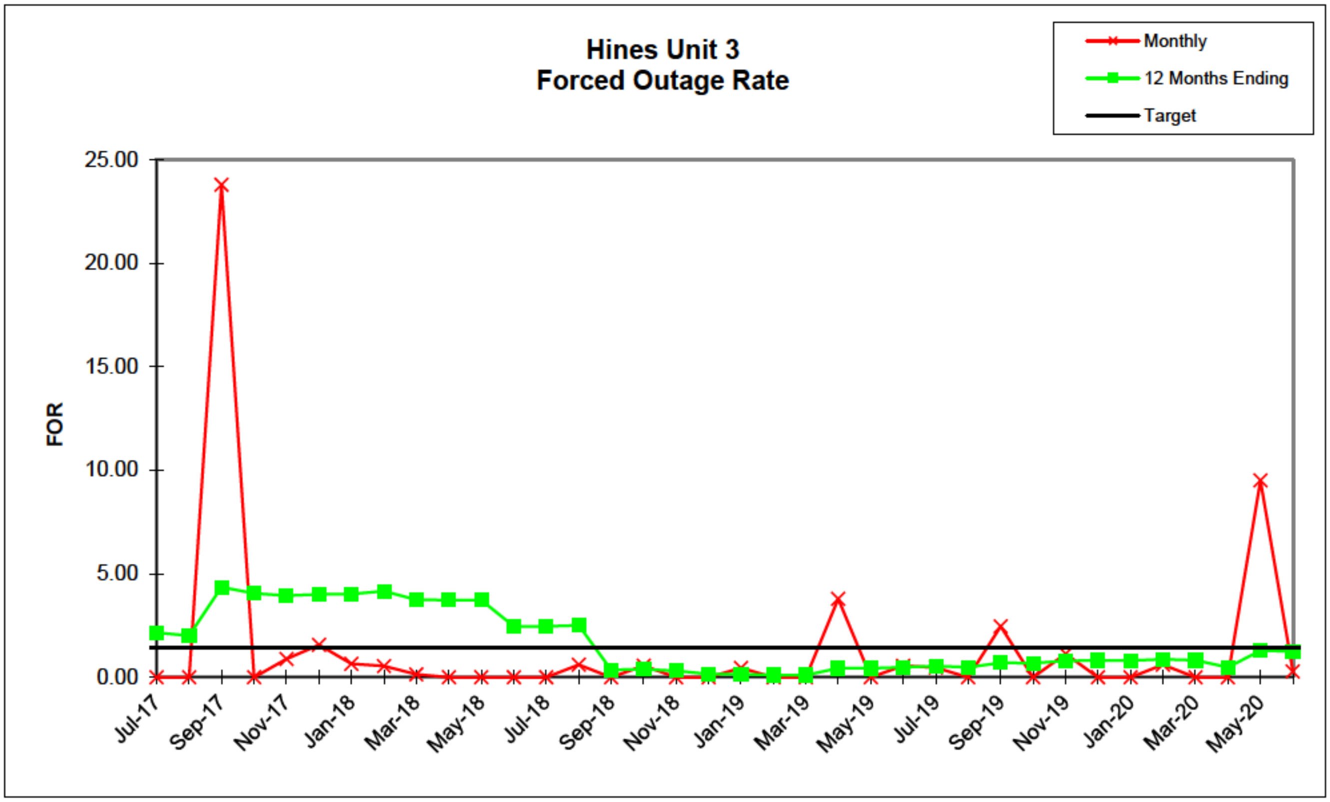
12 MONTHS	**Jul-17**	**Aug-17**	**Sep-17**	**Oct-17**	**Nov-17**	**Dec-17**	**Jan-18**	**Feb-18**	**Mar-18**	**Apr-18**	**May-18**	**Jun-18**	**Jul-18**	**Aug-18**	**Sep-18**	**Oct-18**	**Nov-18**	**Dec-18**
FOR	2.15	2.02	4.36	4.05	3.95	4.01	4.02	4.16	3.74	3.73	3.73	2.47	2.46	2.51	0.35	0.39	0.32	0.15
MOR	1.02	1.02	1.04	0.95	1.35	1.27	0.99	1.02	1.06	1.22	1.50	1.48	1.09	1.09	1.07	1.17	0.76	0.76
PFOR	0.02	0.02	0.42	0.42	0.41	0.41	0.41	0.43	0.40	0.40	0.46	0.46	0.46	0.47	0.10	0.11	0.11	0.09
PMOR	0.06	0.06	0.07	0.06	0.12	0.12	0.05	0.05	0.07	0.09	0.11	0.11	0.14	0.14	0.13	0.15	0.09	0.09
EUOR	3.21	3.08	5.77	5.38	5.70	5.68	5.38	5.55	5.16	5.33	5.66	4.42	4.06	4.13	1.64	1.81	1.27	1.10
EUOF	2.71	2.61	4.88	4.62	4.93	4.93	4.70	4.73	4.69	4.86	5.18	4.04	3.71	3.77	1.49	1.50	1.05	0.90
POF	9.70	9.70	9.70	8.83	7.18	7.18	7.18	7.18	0.00	0.00	0.00	0.00	0.00	0.00	0.53	8.58	8.59	8.59
EAF	87.58	87.69	85.41	86.55	87.89	87.89	88.12	88.10	95.31	95.14	94.82	95.96	96.29	96.23	97.98	89.93	90.36	90.51

Hines
Unit 3

	Jan-19	Feb-19	Mar-19	Apr-19	May-19	Jun-19	Jul-19	Aug-19	Sep-19	Oct-19	Nov-19	Dec-19	Jan-20	Feb-20	Mar-20	Apr-20	May-20	Jun-20
PER HOURS	744.00	672.00	743.00	720.00	744.00	720.00	744.00	744.00	720.00	744.00	721.00	744.00	744.00	696.00	743.00	720.00	744.00	720.00
SER HOURS	700.11	638.34	343.61	606.56	744.00	604.15	726.72	702.23	640.48	190.87	658.48	395.39	460.05	460.19	726.67	655.96	521.00	714.93
RSH	40.69	33.66	399.39	86.52	0.00	112.43	13.86	34.81	63.38	0.00	54.95	348.61	283.95	232.97	16.33	61.54	55.10	3.06
UH	3.20	0.00	0.00	26.93	0.00	3.42	3.43	6.95	16.13	553.13	7.57	0.00	0.00	2.84	0.00	2.50	167.90	2.01
POH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	553.13	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
FOH	3.20	0.00	0.00	23.93	0.00	3.42	3.43	0.00	16.13	0.00	7.57	0.00	0.00	2.84	0.00	0.00	54.77	2.01
MOH	0.00	0.00	0.00	3.00	0.00	0.00	0.00	6.95	0.01	0.00	0.00	0.00	0.00	0.00	0.00	2.50	113.13	0.00
PFOH	3.28	0.00	0.00	24.53	0.00	3.68	0.00	0.00	3.17	0.00	7.77	0.00	0.00	4.00	0.00	0.00	0.00	2.04
LRPF	75.32	0.00	0.00	80.41	0.00	49.58	0.00	0.00	83.25	0.00	87.28	0.00	0.00	61.59	0.00	0.00	0.00	88.11
EFOH	0.48	0.00	0.00	3.82	0.00	0.35	0.00	0.00	0.51	0.00	1.31	0.00	0.00	0.48	0.00	0.00	0.00	0.35
PMOH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
LRPM	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
EMOH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
NPC	516.00	516.00	516.00	516.00	516.00	516.00	516.00	516.00	516.00	516.00	516.00	516.00	515.00	515.00	515.00	515.00	515.00	515.00

MONTHLY	**Jan-19**	**Feb-19**	**Mar-19**	**Apr-19**	**May-19**	**Jun-19**	**Jul-19**	**Aug-19**	**Sep-19**	**Oct-19**	**Nov-19**	**Dec-19**	**Jan-20**	**Feb-20**	**Mar-20**	**Apr-20**	**May-20**	**Jun-20**
FOR	0.45	0.00	0.00	3.80	0.00	0.56	0.47	0.00	2.46	0.00	1.14	0.00	0.00	0.61	0.00	0.00	9.51	0.28
MOR	0.00	0.00	0.00	0.49	0.00	0.00	0.00	0.98	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.38	17.84	0.00
PFOR	0.07	0.00	0.00	0.63	0.00	0.06	0.00	0.00	0.08	0.00	0.20	0.00	0.00	0.10	0.00	0.00	0.00	0.05
PMOR	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
EUOR	0.52	0.00	0.00	4.85	0.00	0.62	0.47	0.98	2.54	0.00	1.33	0.00	0.00	0.72	0.00	0.38	24.37	0.33
EUOF	0.49	0.00	0.00	4.27	0.00	0.52	0.46	0.93	2.31	0.00	1.23	0.00	0.00	0.48	0.00	0.35	22.57	0.33
POF	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	74.35	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
EAF	99.51	100.00	100.00	95.73	100.00	99.48	99.54	99.07	97.69	25.65	98.77	100.00	100.00	99.52	100.00	99.65	77.43	99.67

12 MONTHS	**Jan-19**	**Feb-19**	**Mar-19**	**Apr-19**	**May-19**	**Jun-19**	**Jul-19**	**Aug-19**	**Sep-19**	**Oct-19**	**Nov-19**	**Dec-19**	**Jan-20**	**Feb-20**	**Mar-20**	**Apr-20**	**May-20**	**Jun-20**
FOR	0.15	0.12	0.11	0.44	0.44	0.49	0.54	0.48	0.71	0.69	0.79	0.82	0.81	0.87	0.82	0.48	1.29	1.25
MOR	0.74	0.72	0.63	0.51	0.21	0.21	0.04	0.14	0.14	0.14	0.14	0.14	0.15	0.15	0.14	0.14	1.79	1.76
PFOR	0.09	0.08	0.08	0.14	0.07	0.08	0.08	0.07	0.07	0.07	0.09	0.09	0.09	0.10	0.09	0.04	0.04	0.04
PMOR	0.09	0.09	0.07	0.05	0.03	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
EUOR	1.07	1.00	0.90	1.13	0.74	0.80	0.66	0.68	0.92	0.90	1.01	1.06	1.04	1.12	1.06	0.65	3.07	3.00
EUOF	0.90	0.87	0.76	0.94	0.62	0.66	0.54	0.56	0.75	0.74	0.85	0.85	0.80	0.84	0.84	0.52	2.43	2.41
POF	8.59	8.59	8.59	8.59	8.59	8.59	8.59	8.59	8.06	6.33	6.31	6.31	6.31	6.30	6.30	6.30	6.30	6.30
EAF	90.51	90.53	90.65	90.47	90.79	90.75	90.87	90.85	91.19	92.92	92.84	92.84	92.88	92.86	92.86	93.18	91.27	91.29


Hines Unit 3
Forced Outage Rate
Monthly
12 Months Ending
Target
FOR
25.00
20.00
15.00
10.00
5.00
0.00
Jul-17
Sep-17
Nov-17
Jan-18
Mar-18
May-18
Jul-18
Sep-18
Nov-18
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May-19
Jul-19
Sep-19
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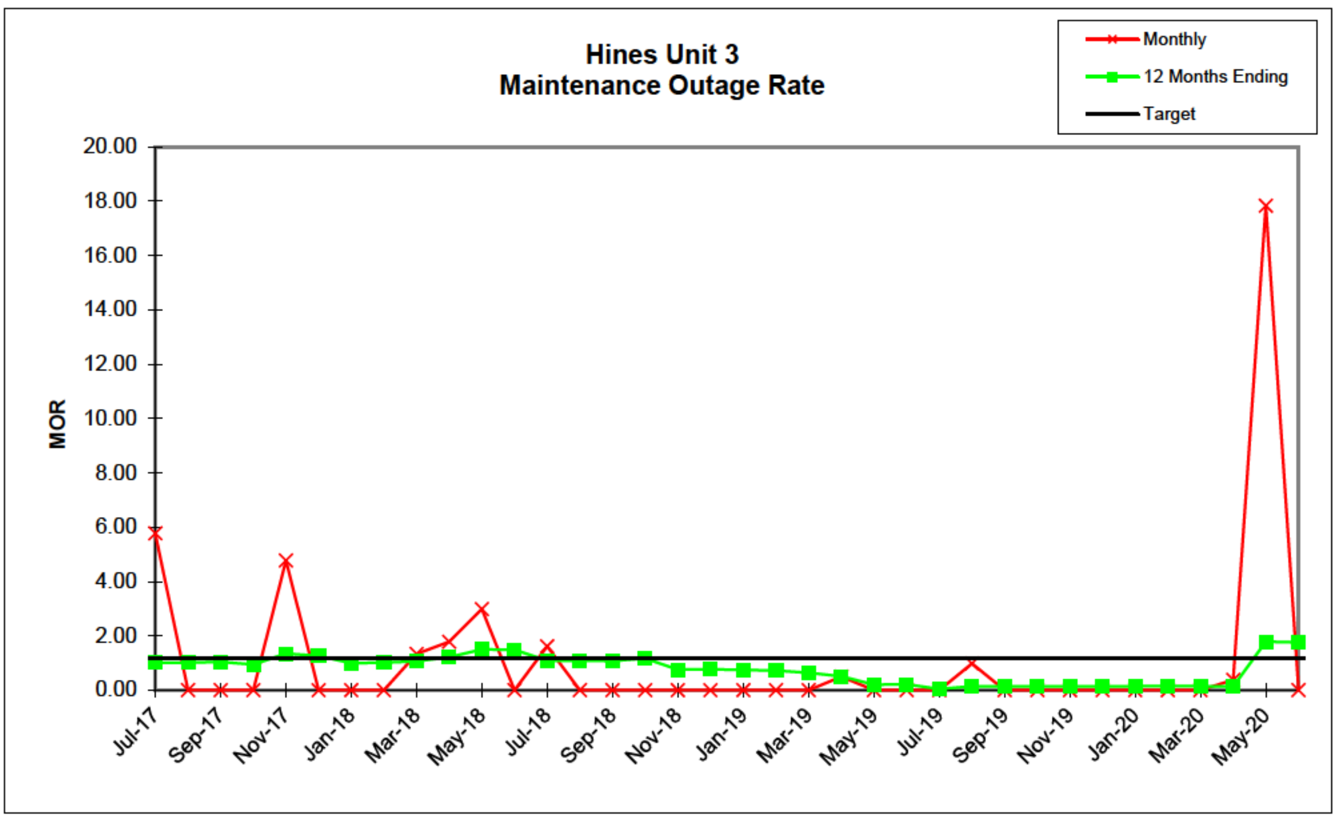
Jan-20
Mar-20
May-20


Hines Unit 3
Maintenance Outage Rate
Monthly
12 Months Ending
Target
MOR
20.00
18.00
16.00
14.00
12.00
10.00
8.00
6.00
4.00
2.00
0.00
Jul-17
Sep-17
Nov-17
Jan-18
Mar-18
May-18
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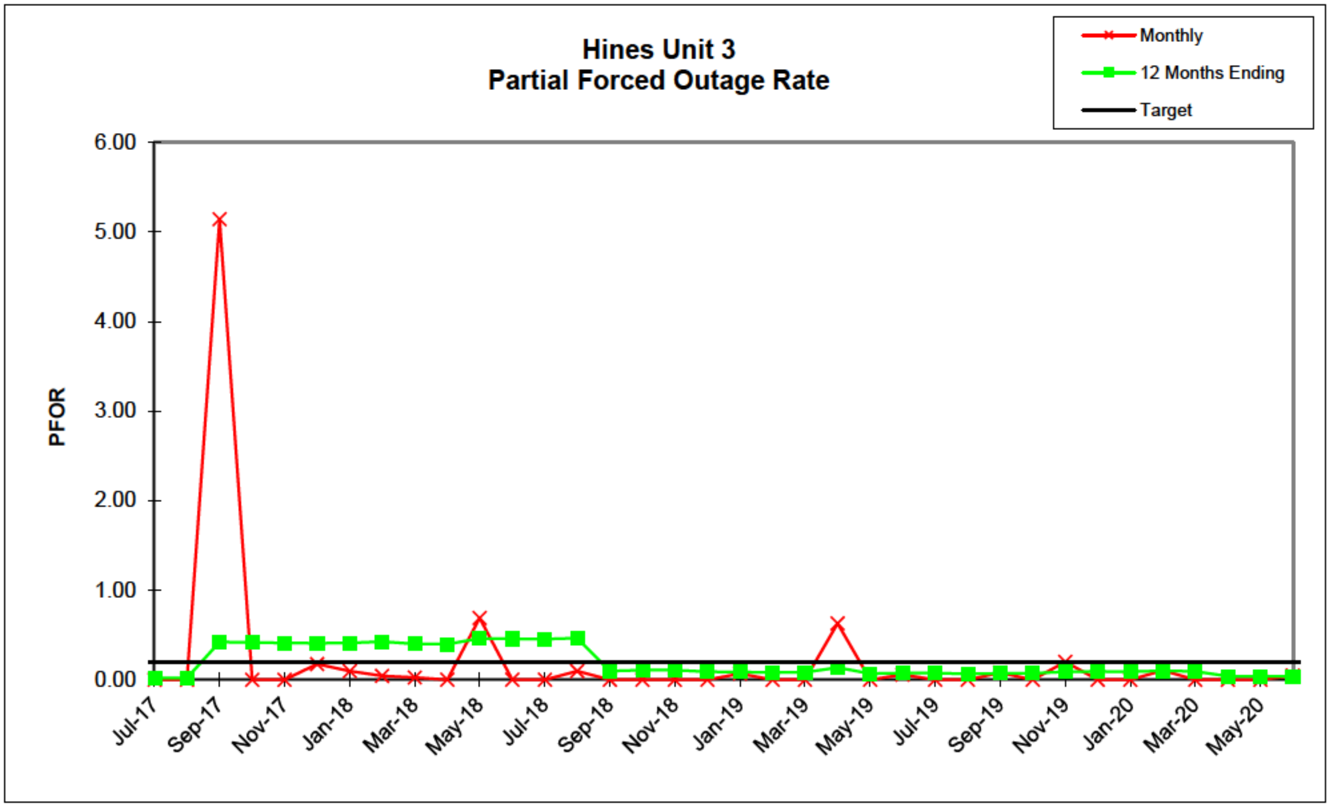
Jan-20
Mar-20
May-20


Hines Unit 3
Partial Forced Outage Rate
Monthly
12 Months Ending
Target
PFOR
6.00
5.00
4.00
3.00
2.00
1.00
0.00
Jul-17
Sep-17
Nov-17
Jan-18
Mar-18
May-18
Jul-18
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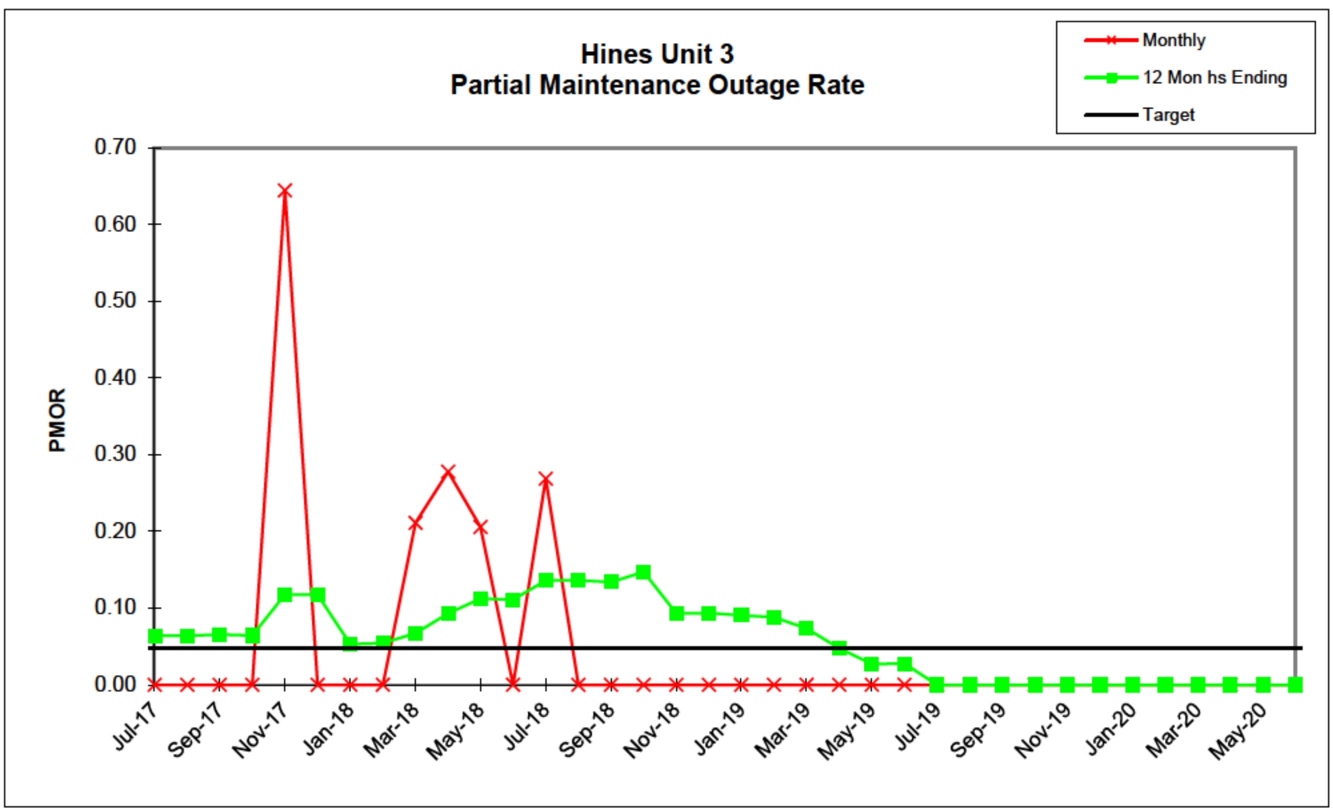
Jan-20
Mar-20
May-20


Hines Unit 3
Partial Maintenance Outage Rate
Monthly
12 Mon hs Ending
Target
PMOR
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
Jul-17
Sep-17
Nov-17
Jan-18
Mar-18
May-18
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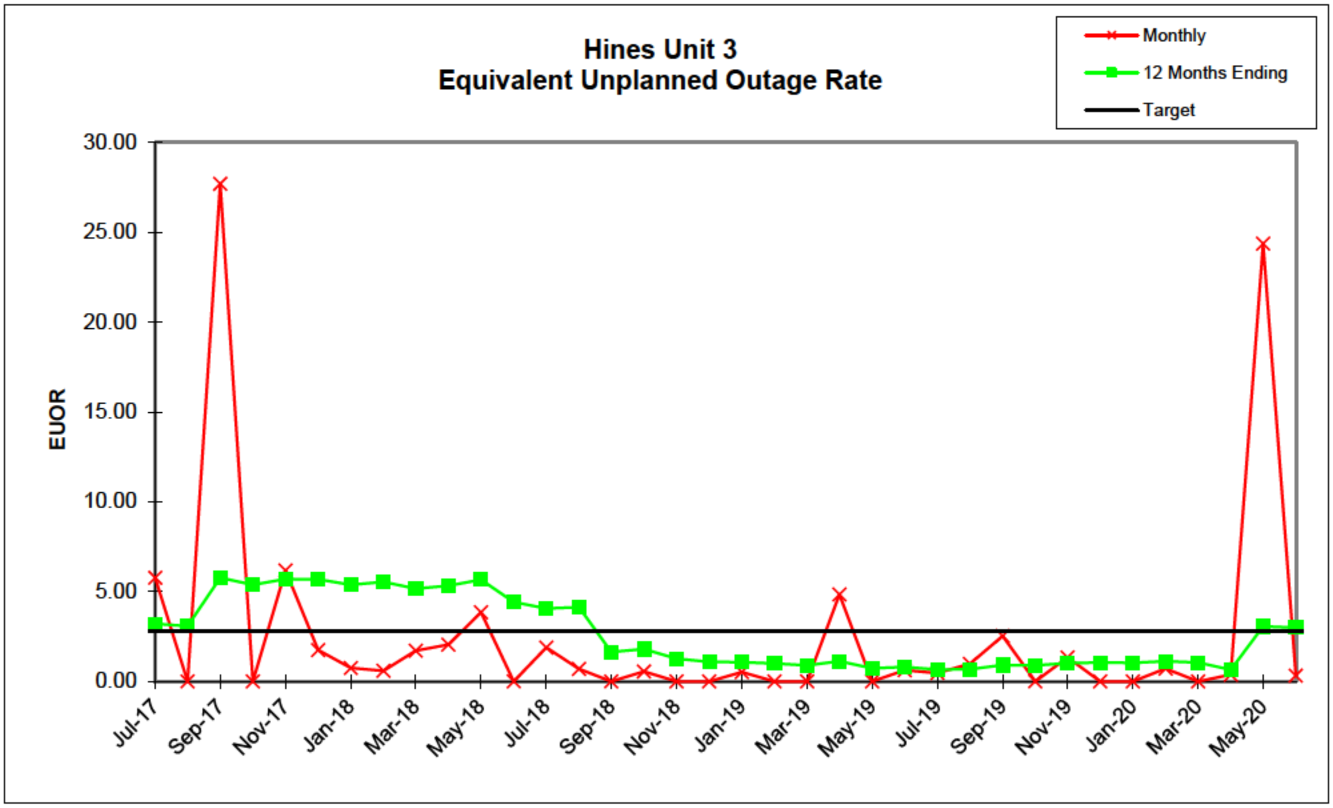
Jan-20
Mar-20
May-20


Hines Unit 3
Equivalent Unplanned Outage Rate
Monthly
12 Months Ending
Target
EUOR
30.00
25.00
20.00
15.00
10.00
5.00
0.00
Jul-17
Sep-17
Nov-17
Jan-18
Mar-18
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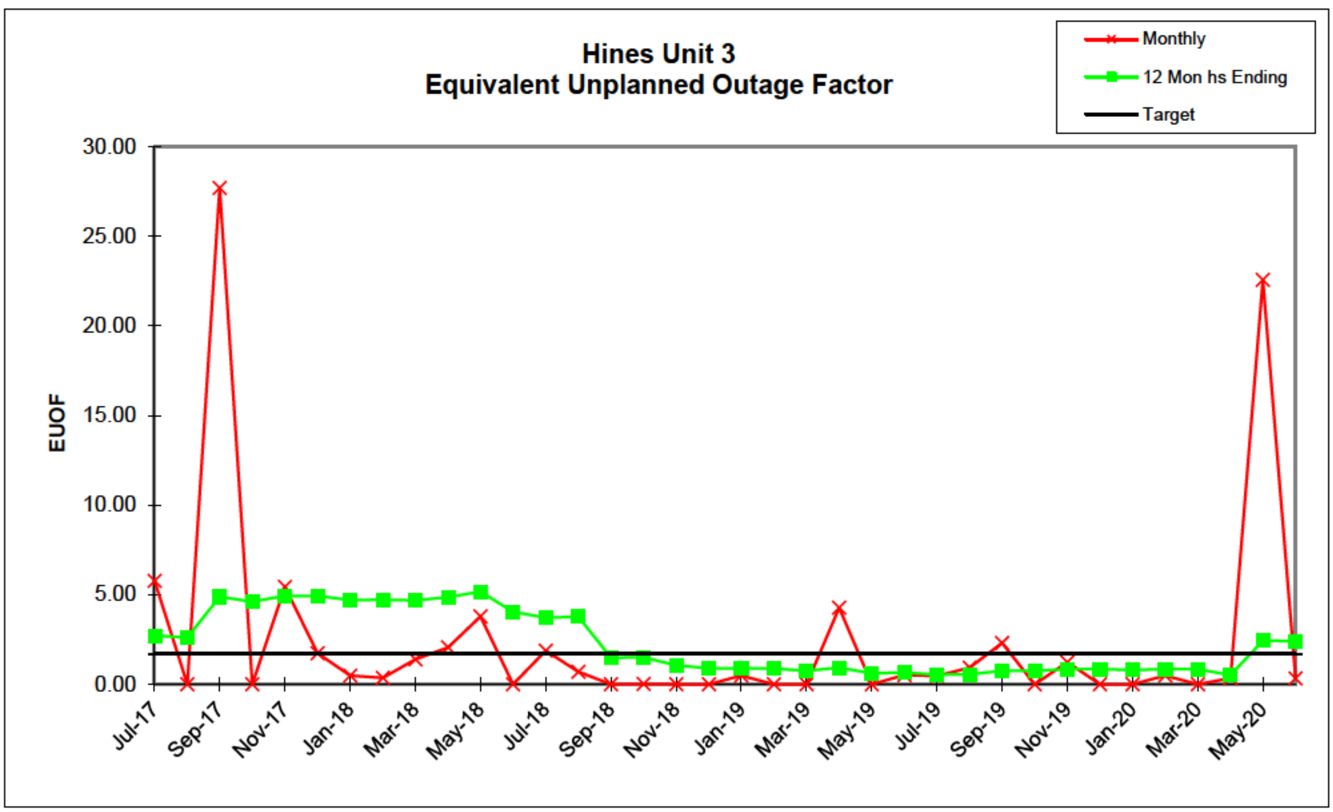

Hines Unit 3
Equivalent Unplanned Outage Factor
Monthly
12 Mon hs Ending
Target
EUOF
30.00
25.00
20.00
15.00
10.00
5.00
0.00
Jul-17
Sep-17
Nov-17
Jan-18
Mar-18
May-18
Jul-18
Sep-18
Nov-18
Jan-19
Mar-19
May-19
Jul-19
Sep-19
Nov-19
Jan-20
Mar-20
May-20

Hines
Unit 4

	Jul-17	Aug-17	Sep-17	Oct-17	Nov-17	Dec-17	Jan-18	Feb-18	Mar-18	Apr-18	May-18	Jun-18	Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18
PER HOURS	744.00	744.00	720.00	744.00	721.00	744.00	744.00	672.00	743.00	720.00	744.00	720.00	744.00	744.00	720.00	744.00	721.00	744.00
SER HOURS	675.38	708.20	711.67	741.07	212.06	377.19	574.23	630.03	743.00	697.74	744.00	718.97	734.94	715.29	720.00	640.18	0.00	436.62
RSH	9.16	2.29	8.33	0.00	18.28	78.42	156.80	41.97	0.00	4.75	0.00	0.00	0.00	5.44	0.00	103.82	328.02	76.72
UH	59.46	33.51	0.00	2.93	490.66	288.39	12.97	0.00	0.00	17.52	0.00	1.03	9.06	23.27	0.00	0.00	392.98	230.66
POH	0.00	0.00	0.00	0.00	489.55	288.39	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	392.98	194.46
FOH	50.46	33.51	0.00	2.93	1.11	0.00	12.97	0.00	0.00	0.00	0.00	1.03	4.99	22.28	0.00	0.00	0.00	36.20
MOH	9.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	17.52	0.00	0.00	4.07	0.99	0.00	0.00	0.00	0.00
PFOH	171.67	20.32	0.00	3.30	1.25	0.00	11.99	0.00	0.00	0.00	0.58	0.97	4.71	57.32	0.00	0.00	0.00	19.40
LRPF	74.14	67.81	0.00	87.68	99.69	0.00	69.17	0.00	0.00	0.00	54.26	76.15	71.10	34.84	0.00	0.00	0.00	67.16
EFOH	24.15	2.61	0.00	0.55	0.24	0.00	1.65	0.00	0.00	0.00	0.06	0.15	0.66	3.96	0.00	0.00	0.00	2.59
PMOH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	16.52	0.00	0.00	3.84	0.00	0.00	0.00	0.00	0.00
LRPM	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	78.14	0.00	0.00	79.10	0.00	0.00	0.00	0.00	0.00
EMOH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	2.56	0.00	0.00	0.60	0.00	0.00	0.00	0.00	0.00
NPC	527.00	527.00	527.00	527.00	527.00	527.00	504.00	504.00	504.00	504.00	504.00	504.00	504.00	504.00	504.00	504.00	504.00	504.00

MONTHLY	**Jul-17**	**Aug-17**	**Sep-17**	**Oct-17**	**Nov-17**	**Dec-17**	**Jan-18**	**Feb-18**	**Mar-18**	**Apr-18**	**May-18**	**Jun-18**	**Jul-18**	**Aug-18**	**Sep-18**	**Oct-18**	**Nov-18**	**Dec-18**
FOR	6.95	4.52	0.00	0.39	0.52	0.00	2.21	0.00	0.00	0.00	0.00	0.14	0.67	3.02	0.00	0.00	0.00	7.66
MOR	1.32	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	2.45	0.00	0.00	0.55	0.14	0.00	0.00	0.00	0.00
PFOR	3.58	0.37	0.00	0.07	0.11	0.00	0.29	0.00	0.00	0.00	0.01	0.02	0.09	0.55	0.00	0.00	0.00	0.59
PMOR	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.37	0.00	0.00	0.08	0.00	0.00	0.00	0.00	0.00
EUOR	11.38	4.87	0.00	0.47	0.63	0.00	2.49	0.00	0.00	2.81	0.01	0.16	1.39	3.69	0.00	0.00	0.00	8.20
EUOF	11.24	4.86	0.00	0.47	0.19	0.00	1.96	0.00	0.00	2.79	0.01	0.16	1.39	3.66	0.00	0.00	0.00	5.21
POF	0.00	0.00	0.00	0.00	67.90	38.76	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	54.50	26.14
EAF	88.76	95.14	100.00	99.53	31.91	61.24	98.04	100.00	100.00	97.21	99.99	99.84	98.61	96.34	100.00	100.00	45.50	68.65

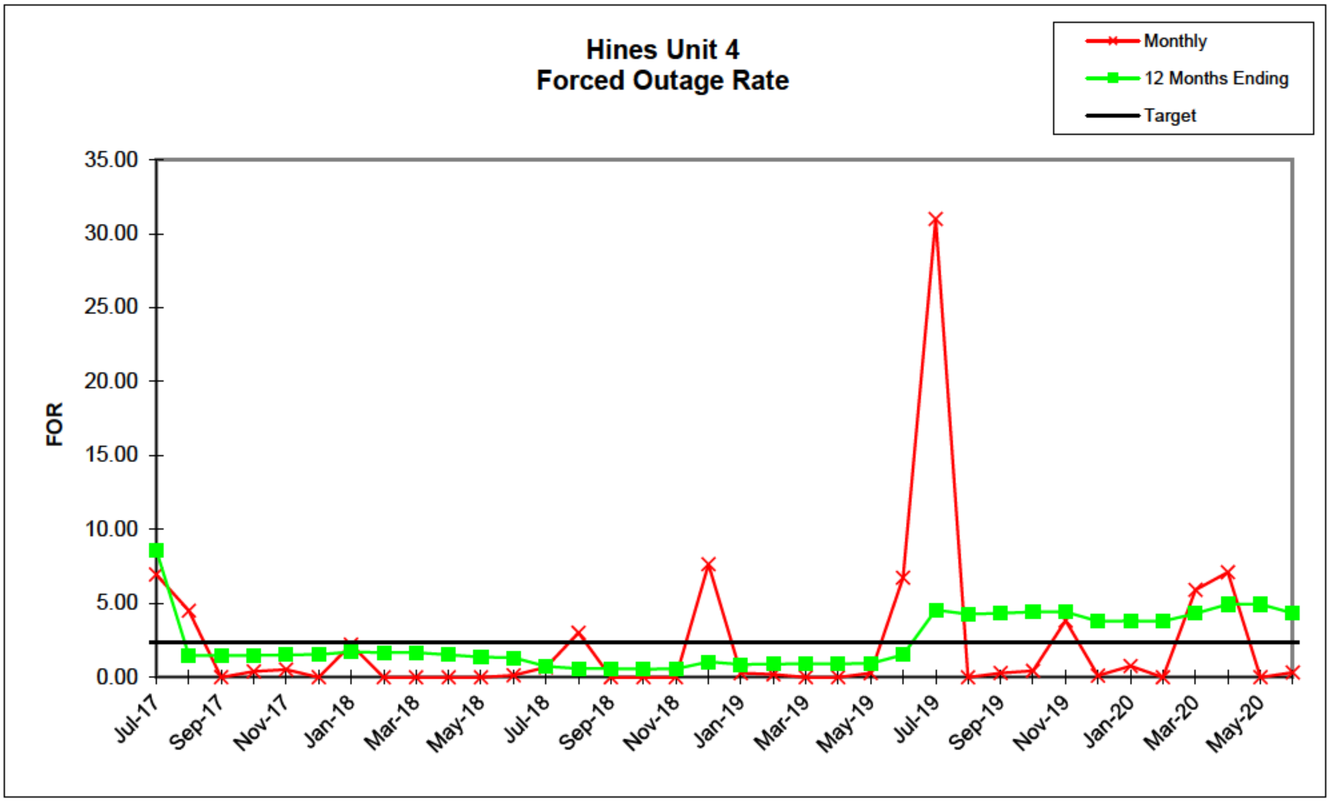
12 MONTHS	**Jul-17**	**Aug-17**	**Sep-17**	**Oct-17**	**Nov-17**	**Dec-17**	**Jan-18**	**Feb-18**	**Mar-18**	**Apr-18**	**May-18**	**Jun-18**	**Jul-18**	**Aug-18**	**Sep-18**	**Oct-18**	**Nov-18**	**Dec-18**
FOR	8.62	1.48	1.48	1.47	1.53	1.53	1.72	1.68	1.68	1.51	1.36	1.34	0.74	0.59	0.59	0.56	0.56	1.04
MOR	1.16	1.08	1.08	1.05	0.55	0.32	0.33	0.32	0.32	0.55	0.55	0.35	0.28	0.30	0.30	0.30	0.31	0.31
PFOR	0.49	0.49	0.49	0.48	0.50	0.50	0.53	0.52	0.52	0.52	0.48	0.39	0.08	0.10	0.10	0.09	0.09	0.12
PMOR	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.03	0.03	0.03	0.04	0.04	0.04	0.04	0.04	0.04
EUOR	10.03	2.99	3.00	2.97	2.55	2.34	2.55	2.50	2.50	2.59	2.40	2.09	1.14	1.02	1.02	0.99	1.00	1.51
EUOF	8.80	2.63	2.63	2.66	2.20	2.01	2.18	2.17	2.17	2.25	2.10	1.83	1.00	0.89	0.89	0.85	0.84	1.28
POF	7.93	7.93	7.93	6.44	9.40	9.04	9.04	9.04	9.04	8.88	8.88	8.88	8.88	8.88	8.88	8.88	7.78	6.71
EAF	83.28	89.45	89.45	90.91	88.40	88.95	88.78	88.79	88.79	88.87	89.02	89.29	90.12	90.23	90.23	90.27	91.38	92.01

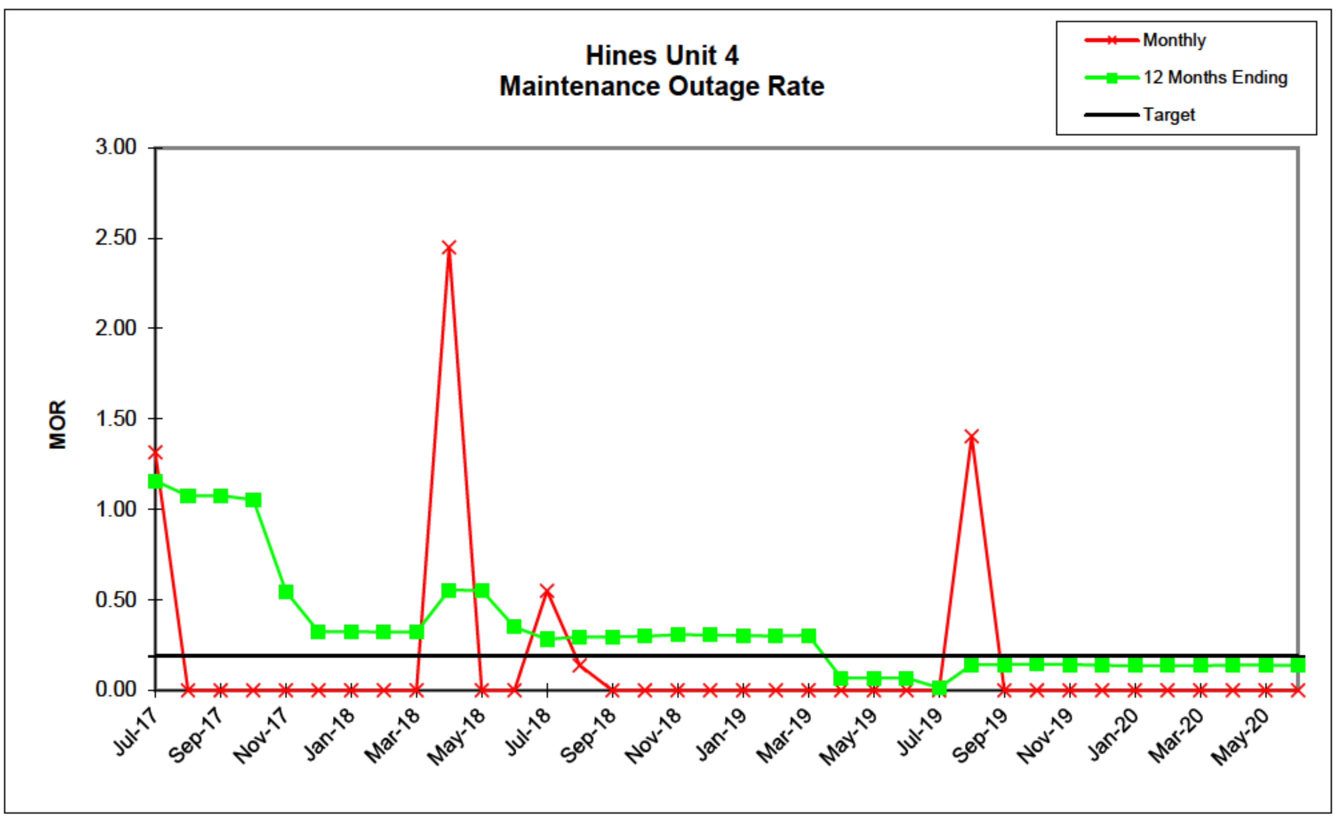
Hines
Unit 4

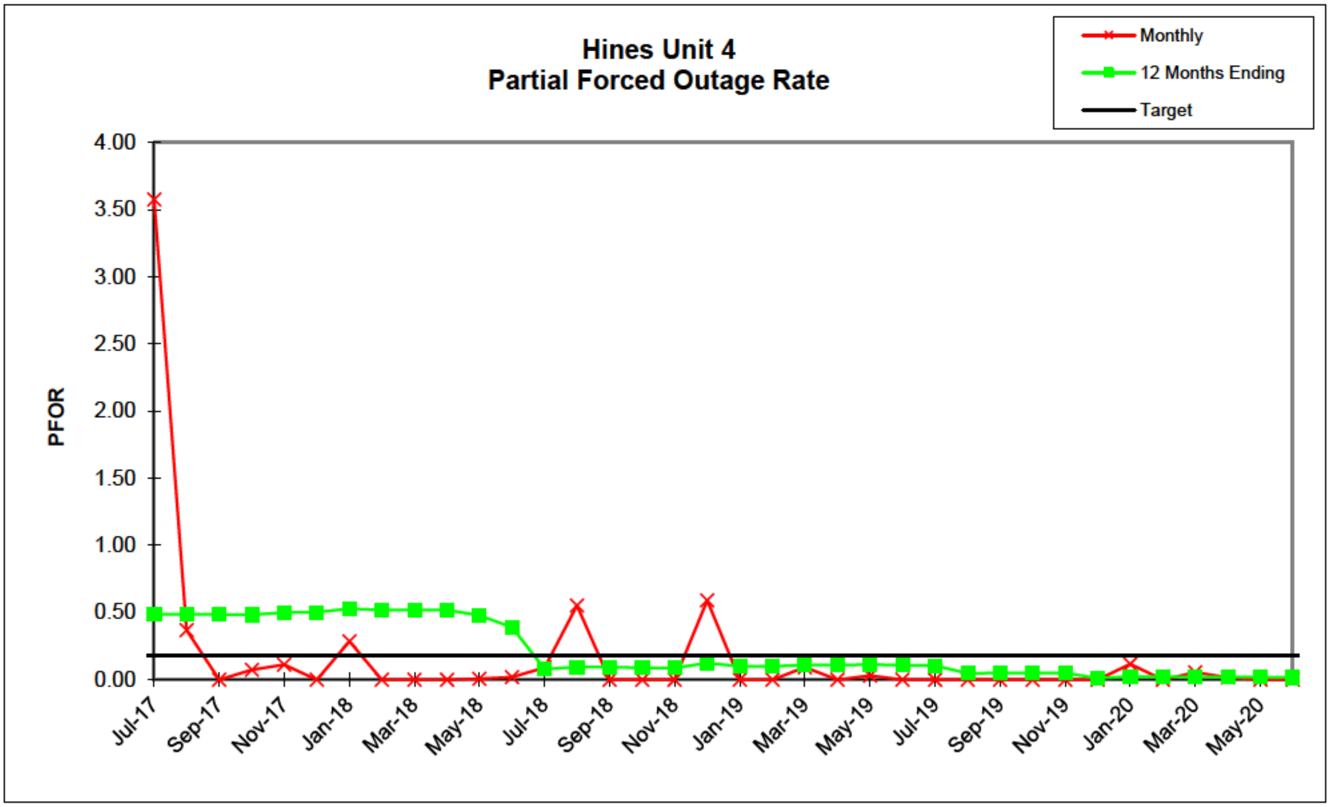
	Jan-19	Feb-19	Mar-19	Apr-19	May-19	Jun-19	Jul-19	Aug-19	Sep-19	Oct-19	Nov-19	Dec-19	Jan-20	Feb-20	Mar-20	Apr-20	May-20	Jun-20
PER HOURS	744.00	672.00	743.00	720.00	744.00	720.00	744.00	744.00	720.00	744.00	721.00	744.00	744.00	696.00	743.00	720.00	744.00	720.00
SER HOURS	677.19	637.21	680.19	678.23	738.92	603.62	509.75	702.35	685.27	542.99	53.31	734.79	720.85	648.90	663.15	556.20	697.39	717.64
RSH	64.80	33.43	62.81	41.77	2.89	72.83	5.43	31.65	32.76	55.83	0.00	1.49	17.57	47.10	38.15	121.23	46.61	0.00
UH	2.01	1.35	0.00	0.00	2.19	43.55	228.81	10.00	1.97	145.18	667.69	7.72	5.58	0.00	41.70	42.57	0.00	2.36
POH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	142.82	665.56	6.91	0.00	0.00	0.00	0.00	0.00	0.00
FOH	2.01	1.35	0.00	0.00	2.19	43.55	228.81	0.00	1.97	2.36	2.13	0.81	5.58	0.00	41.70	42.57	0.00	2.36
MOH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	10.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PFOH	0.00	0.00	8.50	0.00	2.11	0.00	0.00	0.00	0.00	0.00	0.00	0.00	5.58	0.00	3.00	0.58	0.00	0.00
LRPF	0.00	0.00	38.73	0.00	55.13	0.00	0.00	0.00	0.00	0.00	0.00	0.00	78.07	0.00	62.43	89.00	0.00	0.00
EFOH	0.00	0.00	0.64	0.00	0.23	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.84	0.00	0.36	0.10	0.00	0.00
PMOH	0.00	2.60	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
LRPM	0.00	78.09	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
EMOH	0.00	0.39	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
NPC	516.00	516.00	516.00	516.00	516.00	516.00	516.00	516.00	516.00	516.00	516.00	516.00	516.00	516.00	516.00	516.00	516.00	516.00

MONTHLY	**Jan-19**	**Feb-19**	**Mar-19**	**Apr-19**	**May-19**	**Jun-19**	**Jul-19**	**Aug-19**	**Sep-19**	**Oct-19**	**Nov-19**	**Dec-19**	**Jan-20**	**Feb-20**	**Mar-20**	**Apr-20**	**May-20**	**Jun-20**
FOR	0.30	0.21	0.00	0.00	0.30	6.73	30.98	0.00	0.29	0.43	3.84	0.11	0.77	0.00	5.92	7.11	0.00	0.33
MOR	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.40	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PFOR	0.00	0.00	0.09	0.00	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.12	0.00	0.05	0.02	0.00	0.00
PMOR	0.00	0.06	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
EUOR	0.30	0.27	0.09	0.00	0.33	6.73	30.98	1.40	0.29	0.43	3.84	0.11	0.88	0.00	5.97	7.13	0.00	0.33
EUOF	0.27	0.26	0.09	0.00	0.32	6.05	30.75	1.34	0.27	0.32	0.30	0.11	0.86	0.00	5.66	5.93	0.00	0.33
POF	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	19.20	92.31	0.93	0.00	0.00	0.00	0.00	0.00	0.00
EAF	99.73	99.74	99.91	100.00	99.68	93.95	69.25	98.66	99.73	80.49	7.39	98.96	99.14	100.00	94.34	94.07	100.00	99.67

12 MONTHS	**Jan-19**	**Feb-19**	**Mar-19**	**Apr-19**	**May-19**	**Jun-19**	**Jul-19**	**Aug-19**	**Sep-19**	**Oct-19**	**Nov-19**	**Dec-19**	**Jan-20**	**Feb-20**	**Mar-20**	**Apr-20**	**May-20**	**Jun-20**
FOR	0.88	0.90	0.91	0.91	0.94	1.53	4.56	4.28	4.33	4.42	4.41	3.79	3.81	3.79	4.32	4.93	4.93	4.34
MOR	0.30	0.30	0.30	0.07	0.07	0.07	0.01	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14
PFOR	0.10	0.10	0.11	0.11	0.11	0.11	0.11	0.05	0.05	0.05	0.05	0.01	0.02	0.02	0.02	0.02	0.02	0.02
PMOR	0.04	0.05	0.05	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.00	0.00	0.00	0.00	0.00
EUOR	1.32	1.34	1.36	1.10	1.13	1.72	4.68	4.46	4.51	4.60	4.60	3.93	3.97	3.94	4.47	5.08	5.08	4.49
EUOF	1.14	1.16	1.17	0.94	0.96	1.45	3.94	3.74	3.77	3.79	3.82	3.38	3.43	3.41	3.88	4.36	4.34	3.87
POF	6.71	6.71	6.71	6.71	6.71	6.71	6.71	6.71	6.71	8.34	11.45	9.31	9.31	9.28	9.28	9.28	9.28	9.28
EAF	92.16	92.14	92.13	92.36	92.33	91.85	89.35	89.55	89.53	87.87	84.73	87.31	87.26	87.31	86.84	86.36	86.38	86.85


Hines Unit 4
Forced Outage Rate
Monthly
12 Months Ending
Target
FOR
35.00
30.00
25.00
20.00
15.00
10.00
5.00
0.00
Jul-17
Sep-17
Nov-17
Jan-18
Mar-18
May-18
Jul-18
Sep-18
Nov-18
Jan-19
Mar-19
May-19
Jul-19
Sep-19
Nov-19
Jan-20
Mar-20
May-20


Hines Unit 4
Maintenance Outage Rate
Monthly
12 Months Ending
Target
MOR
3.00
2.50
2.00
1.50
1.00
0.50
0.00
Jul-17
Sep-17
Nov-17
Jan-18
Mar-18
May-18
Jul-18
Sep-18
Nov-18
Jan-19
Mar-19
May-19
Jul-19
Sep-19
Nov-19
Jan-20
Mar-20
May-20


Hines Unit 4
Partial Forced Outage Rate
Monthly
12 Months Ending
Target
PFOR
4.00
3.50
3.00
2.50
2.00
1.50
1.00
0.50
0.00
Jul-17
Sep-17
Nov-17
Jan-18
Mar-18
May-18
Jul-18
Sep-18
Nov-18
Jan-19
Mar-19
May-19
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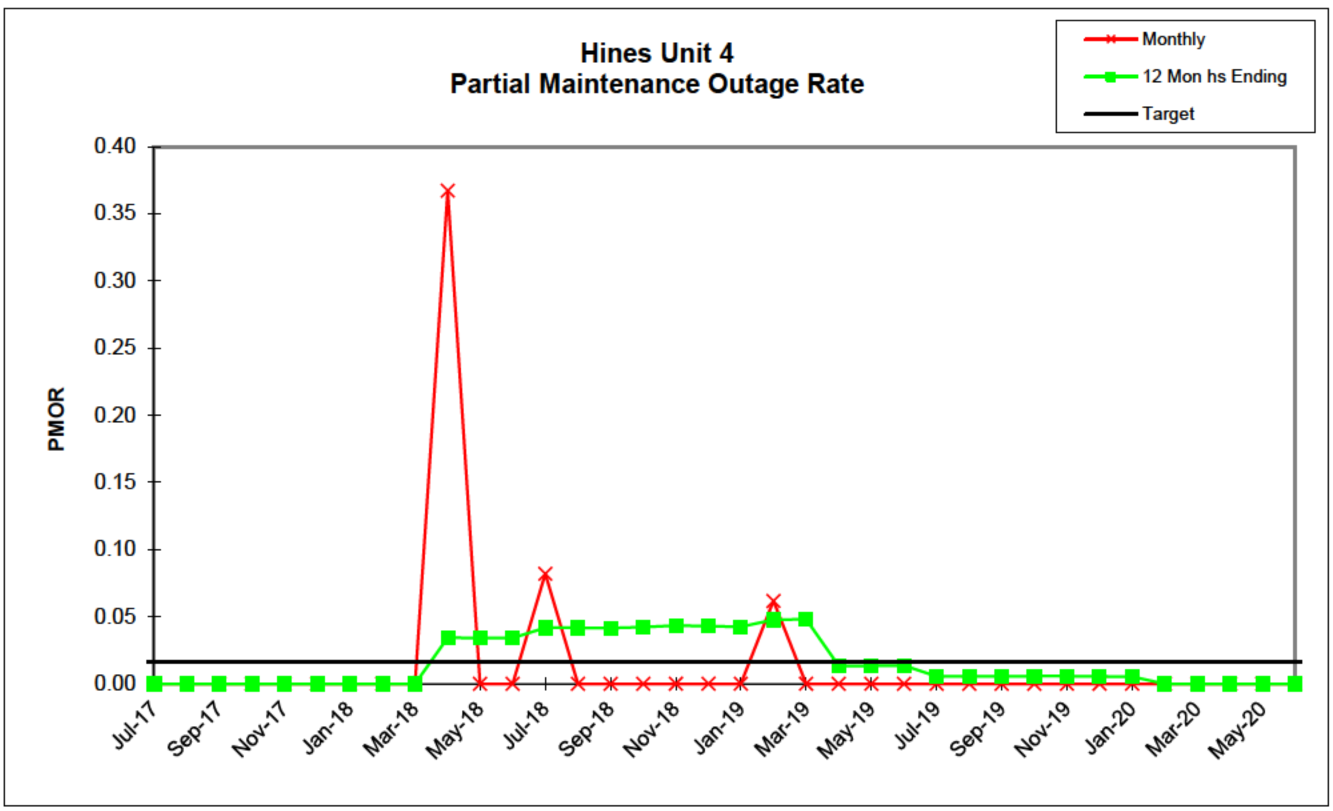
Jan-20
Mar-20
May-20


Hines Unit 4
Partial Maintenance Outage Rate
Monthly
12 Mon hs Ending
Target
PMOR
0.40
0.35
0.30
0.25
0.20
0.15
0.10
0.05
0.00
Jul-17
Sep-17
Nov-17
Jan-18
Mar-18
May-18
Jul-18
Sep-18
Nov-18
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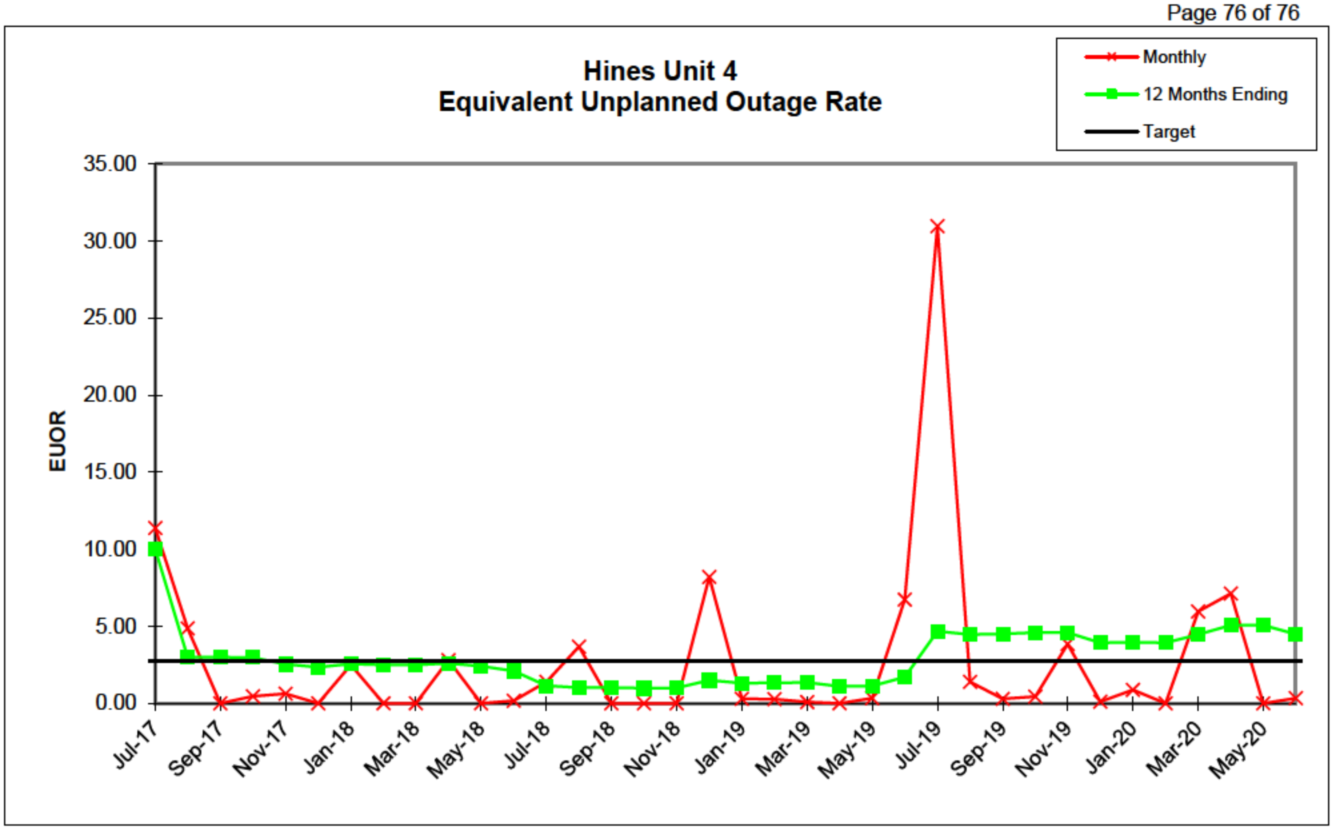
Jul-19
Sep-19
Nov-19
Jan-20
Mar-20
May-20


Hines Unit 4
Equivalent Unplanned Outage Rate
Monthly
12 Months Ending
Target
EUOR
35.00
30.00
25.00
20.00
15.00
10.00
5.00
0.00
Jul-17
Sep-17
Nov-17
Jan-18
Mar-18
May-18
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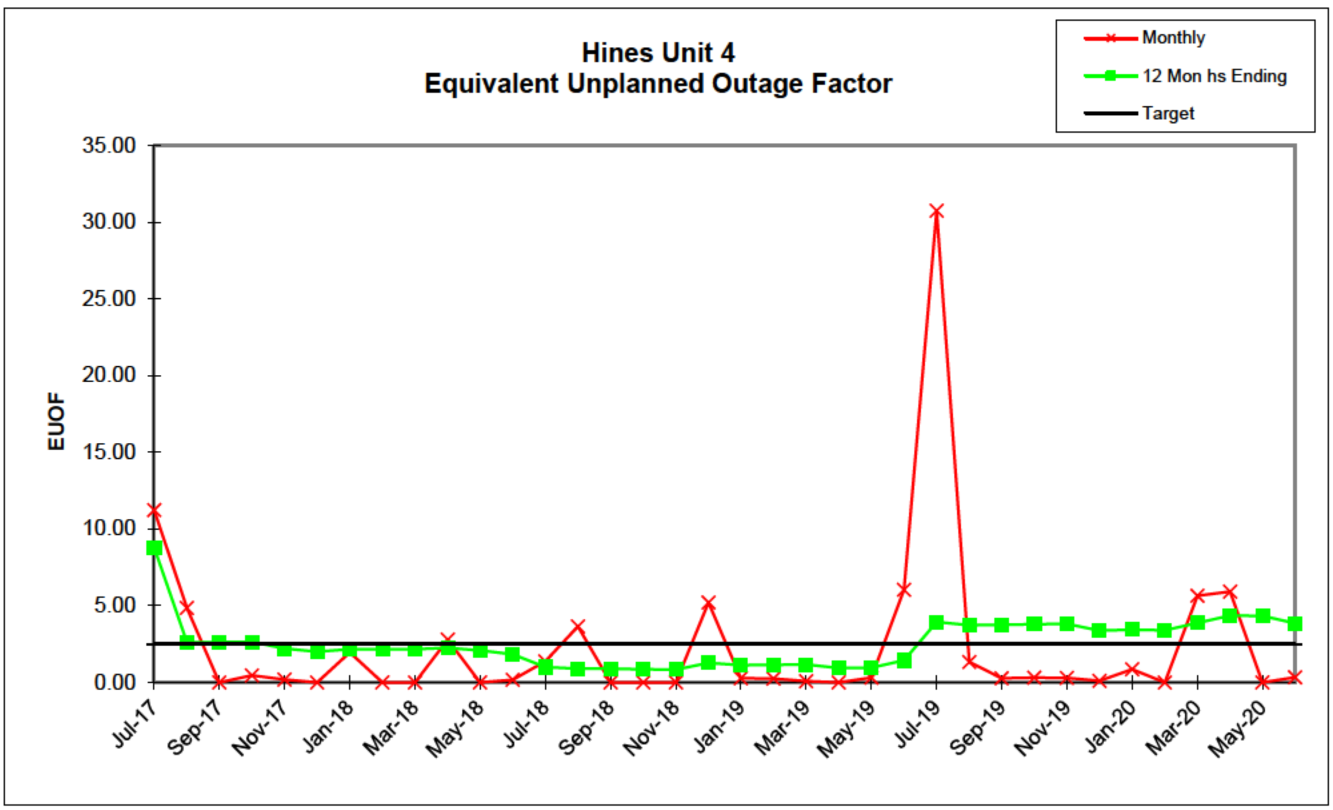
Jan-20
Mar-20
May-20


Hines Unit 4
Equivalent Unplanned Outage Factor
Monthly
12 Mon hs Ending
Target
EUOF
35.00
30.00
25.00
20.00
15.00
10.00
5.00
0.00
Jul-17
Sep-17
Nov-17
Jan-18
Mar-18
May-18
Jul-18
Sep-18
Nov-18
Jan-19
Mar-19
May-19
Jul-19
Sep-19
Nov-19
Jan-20
Mar-20
May-20

Line No.	E1-A True-Up Summary	Total
1	End of Period True-Up [1]	$77,204,120
2	Less - Actual Estimated True-up for the same period [2]	$128,735,937
3	Net True-up for the period	($51,531,817)
4		
5	[1] Page 2, Column 16, Lines 41 & 42	
6	[2] Approved in FPSC Final Order PSC-2019-0484-FOF-EI	
7		
8	( ) Reflects under-recovery	
9		
10	Totals may not add due to rounding	

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20200001-EI EXHIBIT: 10
PARTY: FLORIDA POWER & LIGHT COMPANY – DIRECT
DESCRIPTION: R.B.Deaton RBD-1

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
Line No.	True-up	True Up Line	a-Jan - 2019	a-Feb - 2019	a-Mar - 2019	a-Apr - 2019	a-May - 2019	a-Jun - 2019	a-Jul - 2019	a-Aug - 2019	a-Sep - 2019	a-Oct - 2019	a-Nov - 2019	a-Dec - 2019	a-2019
1	**Fuel Costs & Net Power Transactions**	Fuel Cost of System Net Generation (1)	$247,645,037	$210,407,736	$239,033,820	$240,339,290	$265,852,130	$260,852,387	$257,576,253	$242,828,562	$248,374,166	$242,758,953	$217,693,436	$195,175,246	$2,868,537,018
2		Fuel Cost of Stratified Sales	($2,502,014)	($1,682,735)	($1,748,714)	($2,688,498)	($2,785,905)	($3,537,668)	($3,412,466)	($3,740,146)	($3,166,233)	($3,555,816)	($2,903,428)	($2,908,818)	($34,632,440)
3		Scherer Coal Cars Depreciation & Return													
4		Rail Car Lease (Cedar Bay/ICL/SJRPP)	$431,592	$200,773	$517,637	$288,456	$312,932	$111,960	$175,886	$257,232	$36,235	$163,992	$113,488	$144,570	$2,754,752
5		Fuel Cost of Power Sold (Per A6)	($9,633,494)	($7,019,582)	($6,246,138)	($4,379,818)	($2,828,622)	($2,657,301)	($3,326,575)	($4,855,300)	($3,300,967)	($1,789,066)	($4,980,872)	($3,757,953)	($54,775,689)
6		Gains from Off-System Sales (Per A6)	($4,922,077)	($2,729,301)	($2,317,588)	($1,920,408)	($951,695)	($938,229)	($1,122,124)	($1,962,658)	($1,297,484)	($1,215,518)	($2,858,588)	($1,939,408)	($24,175,079)
7		Fuel Cost of Purchased Power (Per A7)	$2,985,541	$1,982,779	$2,690,113	$2,385,026	$2,396,171	$3,608,732	$2,853,022	$1,945,537	$3,919,643	$2,048,816	$2,532,517	$2,348,824	$31,696,720
8		Energy Payments to Qualifying Facilities (Per A8)	$590,447	$379,280	$398,998	$336,858	$462,632	$639,663	$518,259	$374,924	$596,212	$380,420	$544,180	$343,633	$5,565,507
9		Energy Cost of Economy Purchases (Per A9)	$30,784	$32,530	$559,838	$610,393	$5,635,526	$10,448,887	$2,835,006	$63,539	$4,413,099	$848,272	$55,519	$1,785	$25,535,179
10		Total Fuel Costs & Net Power Transactions	$234,625,816	$201,571,479	$232,887,967	$234,971,299	$268,093,168	$268,528,431	$256,097,261	$234,911,690	$249,574,672	$239,640,053	$210,196,252	$189,407,878	$2,820,505,967
11															
12	**Incremental Optimization Costs**	Incremental Personnel, Software, and Hardware Costs	$45,273	$40,940	$38,239	$40,305	$56,630	$42,240	$46,373	$48,540	$42,427	$46,741	$43,306	$42,051	$533,064
13		Variable Power Plant O&M Attributable to Off-System Sales (Per A6)	$289,804	$224,878	$203,849	$141,000	$87,966	$84,664	$94,130	$155,136	$102,312	$50,107	$182,998	$137,428	$1,754,273
14		Variable Power Plant O&M Avoided due to Economy Purchases (Per A9)	($1,067)	($832)	($8,941)	($9,068)	($74,779)	($145,473)	($39,516)	($1,659)	($58,877)	($16,924)	($1,025)	($111)	($358,271)
15		Total Incremental Optimization Costs	$334,010	$264,985	$233,147	$172,237	$69,817	($18,568)	$100,987	$202,016	$85,862	$79,924	$225,279	$179,369	$1,929,065
16															
17		Dodd Frank Fees											($375)		($375)
18															
19	**Adjustments to Fuel Cost**	Energy Imbalance Fuel Revenues	($177,786)	($133,355)	($3,715)	($58,853)	($171,860)	($25,305)	($181,968)	($41,815)	($80,281)	($58,675)	($93,799)	($36,606)	($1,064,020)
20		Inventory Adjustments	($53,094)	$18,214	($179,394)	$360,284	$705,754	($1,110,949)	$59,322	($49,336)	$37,708	($48,952)	$45,022	$19,252	($196,170)
21		Non Recoverable Oil/Tank Bottoms			$232,871	($549,227)		($1,051,361)		$1,084	($1,084)				($1,367,717)
22		Other O&M Expense (4)				$1,554	$205,738		$196,696	$28,633	$132,828		$8,400		$573,849
23		Adjusted Total Fuel Costs & Net Power Transactions	$234,728,946	$201,721,323	$233,170,876	$234,897,293	$268,902,617	$266,322,249	$256,272,299	$235,052,273	$249,749,704	$239,612,351	$210,380,778	$189,569,892	$2,820,380,600
24															
25	**kWh Sales**	Jurisdictional kWh Sales	8,090,450,684	7,361,664,859	7,987,648,669	8,430,422,795	9,195,507,367	10,476,195,510	10,982,152,510	10,850,301,676	11,097,861,893	10,385,466,073	9,277,887,548	7,793,867,458	111,929,427,042
26		Sales for Resale (excluding Stratified Sales)	398,798,783	418,248,548	387,890,789	426,072,948	452,801,248	540,722,792	564,829,647	577,658,348	563,995,111	542,101,846	538,701,537	409,243,236	5,821,064,833
27		Total Sales	8,489,249,467	7,779,913,407	8,375,539,458	8,856,495,743	9,648,308,615	11,016,918,302	11,546,982,157	11,427,960,024	11,661,857,004	10,927,567,919	9,816,589,085	8,203,110,694	117,750,491,875
28															
29		Jurisdictional % of Total kWh Sales	95.30231%	94.62399%	95.36877%	95.18915%	95.30694%	95.09189%	95.10842%	94.94522%	95.16376%	95.03914%	94.51233%	95.01112%	95.05644%
30															
31	**True-Up Calculation**	Jurisdictional Fuel Revenues (Net of Revenue Taxes)	$216,746,520	$194,169,194	$211,711,391	$211,291,072	$233,391,232	$269,773,583	$284,563,200	$280,559,650	$287,743,740	$266,856,876	$235,011,577	$193,673,527	$2,885,491,562
32															
33	**Fuel Adjustment Revenues Not Applicable to Period**														
34		Prior Period True-Up (Collected)/Refunded This Period (2)	($9,311,710)	($9,311,710)	($9,311,710)	($9,311,710)	($9,311,710)	($9,311,710)	($9,311,710)	($9,311,710)	($9,311,710)	($9,311,710)	($9,311,710)	($9,311,710)	($111,740,516)
35		GPIF, Net of Revenue Taxes (3)	($487,810)	($487,810)	($487,810)	($487,810)	($487,810)	($487,810)	($487,810)	($487,810)	($487,810)	($487,810)	($487,810)	($487,810)	($5,853,723)
36		Incentive Mechanism, Net of Revenue Taxes (5)	($183,580)	($183,580)	($183,580)	($183,580)	($183,580)	($183,580)	($183,580)	($183,580)	($183,580)	($183,580)	($183,580)	($183,580)	($2,202,961)
37		Retail Fuel Revenues Applicable to Period	$206,763,420	$184,186,094	$201,728,291	$201,307,972	$223,408,132	$259,790,483	$274,580,100	$270,576,550	$277,760,640	$256,873,776	$225,028,477	$183,690,427	$2,765,694,362
38		Adjusted Total Fuel Costs & Net Power Transactions	234,728,946	201,721,323	233,170,876	234,897,293	268,902,617	266,322,249	256,272,299	235,052,273	249,749,704	239,612,351	210,380,778	189,569,892	2,820,380,600
39		Retail % of Total kWh Sales	95.30231%	94.62399%	95.36877%	95.18915%	95.30694%	95.09189%	95.10842%	94.94522%	95.16376%	95.03914%	94.51233%	95.01112%	95.05644%
40		Juris. Total Fuel Costs & Net Power Transactions	224,013,054	191,142,083	222,681,294	223,907,536	256,639,089	253,602,879	244,075,328	223,481,105	238,001,572	228,042,056	199,112,157	180,362,834	2,685,060,986
41		True-Up Provision for the Month-Over/(Under) Recovery	($17,249,634)	($6,955,989)	($20,953,003)	($22,599,564)	($33,230,957)	$6,187,604	$30,504,772	$47,095,445	$39,759,068	$28,831,721	$25,916,320	$3,327,593	$80,633,376
42		Interest Provision for the Month	($375,832)	($381,429)	($396,404)	($424,337)	($454,773)	($453,549)	($375,522)	($270,039)	($173,694)	($91,150)	($32,842)	$313	($3,429,256)
43		True-Up & Interest Prov. Beg of Period-Over/(Under) Recovery	($111,740,516)	($120,054,272)	($118,079,980)	($130,117,677)	($143,829,868)	($168,203,888)	($153,158,123)	($113,717,163)	($57,580,048)	($8,682,964)	$29,369,316	$64,564,503	($111,740,516)
44		Deferred True-up Beginning of Period - Over/(Under) Recovery (6)	($70,653,405)	($70,653,405)	($70,653,405)	($70,653,405)	($70,653,405)	($70,653,405)	($70,653,405)	($70,653,405)	($70,653,405)	($70,653,405)	($70,653,405)	($70,653,405)	($70,653,405)
45		Prior Period True-Up Collected/(Refunded) This Period	$9,311,710	$9,311,710	$9,311,710	$9,311,710	$9,311,710	$9,311,710	$9,311,710	$9,311,710	$9,311,710	$9,311,710	$9,311,710	$9,311,710	$111,740,516
46		End of Period Net True-up Amount Over/(Under) Recovery	($190,707,677)	($188,733,385)	($200,771,082)	($214,483,273)	($238,857,293)	($223,811,528)	($184,370,568)	($128,233,453)	($79,336,369)	($41,284,089)	($6,088,902)	$6,550,715	$6,550,715
47															
48															
49	(1) Actuals include various adjustments as noted on the A-Schedules.														
50	(2) Prior Period 2018 Actual/Estimated True-up.														
51	(3) Generating Performance Incentive Factor is (($5,857,941/12) x 99.9280%) - See Order No. PSC-2019-0484-FOF-EI.														
52	(4) Other Fuel Expense consists of nuclear fuel design software maintenance costs.														
53	(5) Jurisdictionalized Incentive Mechanism - FPL Portion is (($2,204,548/12) x 99.9280%) - See Order No. PSC-2018-0610-FOF-EI														
54	(6) 2018 Final True-up.														
55															
56		Totals may not add due to rounding.													

(1)	(2)	(3)	(4)	(5)	(6)	(7)
Line No.	True-up	True Up Line	2019			
			Actuals	Actual/Estimated	Diff $	Diff %
1	**Fuel Costs & Net Power Transactions**	Fuel Cost of System Net Generation [1]	$2,868,537,018	$2,742,695,965	$125,841,052	4.6%
2		Fuel Cost of Stratified Sales	($34,632,440)	($28,202,880)	($6,429,559)	22.8%
3		Rail Car Lease (Cedar Bay/ICL/SJRPP)	$2,754,752	$2,807,537	($52,785)	(1.9%)
4		Fuel Cost of Power Sold (Per A6)	($54,775,689)	($52,136,444)	($2,639,245)	5.1%
5		Gains from Off-System Sales (Per A6)	($24,175,079)	($21,802,243)	($2,372,836)	10.9%
6		Fuel Cost of Purchased Power (Per A7)	$31,696,720	$30,893,610	$803,109	2.6%
7		Energy Payments to Qualifying Facilities (Per A8)	$5,565,507	$5,457,362	$108,146	2.0%
8		Energy Cost of Economy Purchases (Per A9)	$25,535,179	$24,108,353	$1,426,826	5.9%
9		Total Fuel Costs & Net Power Transactions	$2,820,505,967	$2,703,821,260	$116,684,708	4.3%
10						
11	**Incremental Optimization Costs**	Incremental Personnel, Software, and Hardware Costs	$533,064	$526,330	$6,734	1.3%
12		Variable Power Plant O&M Attributable to Off-System Sales (Per A6)	$1,754,273	$1,629,911	$124,361	7.6%
13		Variable Power Plant O&M Avoided due to Economy Purchases (Per A9)	($358,271)	($408,282)	$50,010	(12.2%)
14		Total Incremental Optimization Costs	$1,929,065	$1,747,960	$181,106	10.4%
15		Dodd Frank Fees	($375)	-	($375)	N/A
16						
17	**Adjustments to Fuel Cost**	Energy Imbalance Fuel Revenues	($1,064,020)	($570,875)	($493,145)	86.4%
18		Inventory Adjustments	($196,170)	($259,185)	$63,015	(24.3%)
19		Non Recoverable Oil/Tank Bottoms	($1,367,717)	($1,367,716)	($0)	0.0%
20		Other O&M Expense [2]	$573,849	$565,522	$8,327	1.5%
21		Adjusted Total Fuel Costs & Net Power Transactions	$2,820,380,600	$2,703,936,965	$116,443,636	4.3%
22						
23	**kWh Sales**	Jurisdictional kWh Sales	111,929,427,042	110,337,852,692	1,591,574,350	1.4%
24		Sales for Resale (excluding Stratified Sales)	5,821,064,833	5,237,747,569	583,317,264	11.1%
25		Total Sales	117,750,491,875	115,575,600,261	2,174,891,614	1.9%
26						
27		Jurisdictional % of Total Sales	95.05644%	95.46812%		
28						
29	**True-Up Calculation**	Jurisdictional Fuel Revenues (Net of Revenue Taxes)	$2,885,491,562	$2,835,888,086	$49,603,476	1.7%
30						
31	**Fuel Adjustment Revenues Not Applicable to Period**					
32		Prior Period True-Up (Collected)/Refunded This Period [3]	($111,740,516)	($111,740,516)	-	0.0%
33		GPIF, Net of Revenue Taxes [4]	($5,853,723)	($5,853,723)	-	0.0%
34		Incentive Mechanism, Net of Revenue Taxes [5]	($2,202,961)	($2,202,961)	-	0.0%
35		Jurisdictional Fuel Revenues Applicable to Period	$2,765,694,362	$2,716,090,886	$49,603,476	1.7%
36		Adjusted Total Fuel Costs & Net Power Transactions	2,820,380,600	2,703,936,965	116,443,636	4.3%
37		Jurisdictional Sales % of Total kWh Sales	95.05644%	95.46812%		
38		Juris. Total Fuel Costs & Net Power Transactions	$2,685,060,986	$2,584,104,916	$100,956,070	3.9%
39		True-Up Provision for the Month-Over/(Under) Recovery	$80,633,376	$131,985,970	($51,352,594)	(38.9%)
40		Interest Provision for the Month	($3,429,256)	($3,250,033)	($179,223)	5.5%
41		True-Up & Interest Prov. Beg of Period-Over/(Under) Recovery	($111,740,516)	($111,740,516)	-	0.0%
42		Deferred True-up Beginning of Period - Over/(Under) Recovery [6]	($70,653,405)	($70,653,405)	-	0.0%
43		Prior Period True-Up Collected/(Refunded) This Period	$111,740,516	$111,740,516	-	0.0%
44		End of Period Net True-up Amount Over/(Under) Recovery	$6,550,715	$58,082,532	($51,531,817)	(88.7%)
45						
46						

47 [1] Actuals include various adjustments as noted on the A-Schedules.

48 [2] Other Fuel Expense consists of nuclear fuel design software maintenance costs.

49 [3] Prior Period 2018 Actual/Estimated True-up.

50 [4] Generating Performance Incentive Factor is (($5,857,941/12) x 99.9280%) - See Order No. PSC-2019-0484-FOF-EI.

51 [5] Jurisdictionalized Incentive Mechanism - FPL Portion is (($2,204,548/12) x 99.9280%) - See Order No. PSC-2019-0484-FOF-EI.

52 [6] 2018 Final True-up.

CONFIDENTIAL

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20200001-EI EXHIBIT: 11
PARTY: FLORIDA POWER & LIGHT COMPANY – DIRECT
DESCRIPTION: R.B.Deaton RBD-2

FOR THE ACTUAL/ESTIMATED PERIOD OF: JANUARY 2020 THROUGH DECEMBER 2020

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
Line No.	True Up Section	True Up Line	a-Jan - 2020	a-Feb - 2020	a-Mar - 2020	a-Apr - 2020	a-May - 2020	a-Jun - 2020	Jul - 2020	Aug - 2020	Sep - 2020	Oct - 2020	Nov - 2020	Dec - 2020	2020
1	**Fuel Costs & Net Power Transactions**	Fuel Cost of System Net Generation [1]	185,496,269	173,597,002	181,513,695	178,633,359	202,547,418	214,594,794	211,397,561	221,910,398	208,039,737	211,568,645	192,292,179	215,097,553	2,396,688,611
2		Fuel Cost of Stratified Sales	(2,094,059)	(2,259,573)	(2,232,617)	(2,381,561)	(2,073,042)	(2,254,470)	(3,951,864)	(4,516,441)	(3,808,960)	(3,737,942)	(3,723,535)	(3,048,627)	(36,082,691)
3		Rail Car Lease (Cedar Bay/ICL/SJRPP)	150,371	167,770	159,866	226,043	219,296	215,927	157,046	157,683	157,683	157,046	157,683	157,046	2,083,460
4		Fuel Cost of Power Sold (Per A6)	(7,779,369)	(8,036,378)	(2,876,822)	(3,309,957)	(3,983,636)	(2,767,692)	(2,873,189)	(3,172,581)	(3,308,058)	(3,806,639)	(3,665,091)	(4,989,707)	(50,569,119)
5		Gains from Off-System Sales (Per A6)	(4,426,727)	(4,399,207)	(1,491,017)	(1,603,758)	(2,441,847)	(1,556,051)	(1,393,573)	(1,378,017)	(1,450,675)	(1,409,088)	(1,435,231)	(1,912,955)	(24,898,147)
6		Fuel Cost of Purchased Power (Per A7)	2,427,756	2,257,414	2,165,181	2,433,560	2,007,734	1,781,047	2,306,763	2,205,211	2,559,213	2,305,455	2,420,378	2,422,081	27,291,794
7		Energy Payments to Qualifying Facilities (Per A8)	321,716	405,060	339,253	362,152	340,189	280,482	334,819	317,785	454,126	533,452	451,378	561,069	4,701,482
8		Energy Cost of Economy Purchases (Per A9)	14,565	1,350	1,087,136	572,748	9,950	1,526,812	2,166,590	1,806,990	2,137,200	1,138,320	42,000	27,125	10,530,786
9		Total Fuel Costs & Net Power Transactions	$174,110,520	$161,733,439	$178,664,676	$174,932,586	$196,626,063	$211,820,849	$208,144,153	$217,331,028	$204,780,266	$206,749,249	$186,539,762	$208,313,585	$2,329,746,176
10															
11	**Incremental Optimization Costs**	Incremental Personnel, Software, and Hardware Costs	46,772	43,406	46,420	45,450	43,986	46,732	37,090	38,683	33,906	38,683	37,090	35,498	493,717
12		Variable Power Plant O&M Attributable to Off-System Sales (Per A6)	295,617	320,119	121,837	142,065	169,117	112,095	100,146	103,168	94,575	94,504	126,165	162,208	1,841,614
13		Variable Power Plant O&M Avoided due to Economy Purchases (Per A9)	(624)	(59)	(22,571)	(12,859)	(1,347)	(27,003)	(48,562)	(40,502)	(53,430)	(30,830)	(1,560)	(1,008)	(240,352)
14		Total Incremental Optimization Costs	$341,765	$363,466	$145,687	$174,656	$211,756	$131,824	$88,674	$101,349	$75,051	$102,357	$161,695	$196,698	$2,094,979
15															
16		Dodd Frank Fees	399	-	-	-	-	-	-	-	-	-	-	-	399
17															
18	**Adjustments to Fuel Cost**	Energy Imbalance Fuel Revenues	(80,338)	(47,699)	(54,762)	(81,589)	(59,321)	(71,312)	-	-	-	-	-	-	(395,022)
19		Inventory Adjustments	67,324	(29,576)	14,326	9,656	107,445	(40,469)	-	-	-	-	-	-	128,705
20		Other O&M Expense	-	-	-	-	-	230,839	-	348,990	-	-	-	-	579,829
21		Adjusted Total Fuel Costs & Net Power Transactions	$174,439,670	$162,019,630	$178,769,926	$175,035,309	$196,885,943	$212,071,731	$208,232,828	$217,781,368	$204,855,317	$206,851,605	$186,701,457	$208,510,283	$2,332,155,067
22															
23	**kWh Sales**	Jurisdictional kWh Sales	8,171,566,237	7,512,483,753	7,875,964,458	9,182,676,725	9,179,513,583	10,172,896,382	10,822,490,806	11,189,186,649	10,797,614,351	9,866,490,936	8,805,244,544	7,959,024,047	111,535,152,471
24		Sales for Resale (excluding Stratified Sales)	406,373,114	410,569,706	399,184,391	454,450,732	468,191,181	487,119,537	497,410,009	477,503,452	466,618,753	442,006,697	367,234,372	352,196,378	5,228,858,323
25		Total Sales	8,577,939,351	7,923,053,459	8,275,148,849	9,637,127,457	9,647,704,764	10,660,015,919	11,319,900,815	11,666,690,101	11,264,233,104	10,308,497,633	9,172,478,916	8,311,220,425	116,764,010,794
26															
27		Jurisdictional Sales % of Total kWh Sales	95.26258%	94.81804%	95.17611%	95.28438%	95.14712%	95.43041%	95.60588%	95.90712%	95.85752%	95.71221%	95.99635%	95.76240%	95.52186%
28															
29	**True-Up Calculation**	Jurisdictional Fuel Revenues (Net of Revenue Taxes)	177,353,979	161,495,094	170,048,894	203,756,280	(2,911,081)	227,040,535	239,112,986	247,214,794	238,563,364	217,991,048	194,543,784	175,847,320	2,250,056,998
30		**Fuel Adjustment Revenues Not Applicable to Period**													
31		Prior Period True-Up (Collected)/Refunded This Period [3]	4,840,211	4,840,211	4,840,211	4,840,211	4,840,211	4,840,211	4,840,211	4,840,211	4,840,211	4,840,211	4,840,211	4,840,211	58,082,532
32		GPIF, Net of Revenue Taxes [4]	(714,241)	(714,241)	(714,241)	(714,241)	(714,241)	(714,241)	(714,241)	(714,241)	(714,241)	(714,241)	(714,241)	(714,241)	(8,570,896)
33		Incentive Mechanism, Net of Revenue Taxes [5]	(1,064,771)	(1,064,771)	(1,064,771)	(1,064,771)	(1,064,771)	(1,064,771)	(1,064,771)	(1,064,771)	(1,064,771)	(1,064,771)	(1,064,771)	(1,064,771)	(12,777,254)
34		Solar Together - Subscription Credit, Net of Revenue Taxes [6]	-	-	-	(2,926,367)	(2,838,531)	(3,117,085)	(3,111,156)	(2,815,351)	(2,888,834)	(2,543,459)	(2,325,736)	(2,495,417)	(25,061,936)
35		**Jurisdictional Fuel Revenues Applicable to Period**	$180,415,177	$164,556,293	$173,110,093	$203,891,112	($2,688,413)	$226,984,648	$239,063,029	$247,460,642	$238,735,729	$218,508,788	$195,279,247	$176,413,102	$2,261,729,445
36		Adjusted Total Fuel Costs & Net Power Transactions	174,439,670	162,019,630	178,769,926	175,035,309	196,885,943	212,071,731	208,232,828	217,781,368	204,855,317	206,851,605	186,701,457	208,510,283	2,332,155,067
37		Jurisdictional Sales % of Total kWh Sales	95.26258%	94.81804%	95.17611%	95.28438%	95.14712%	95.43041%	95.60588%	95.90712%	95.85752%	95.71221%	95.99635%	95.76240%	95.52186%
38		Juris. Total Fuel Costs & Net Power Transactions	$166,395,082	$153,826,621	$170,370,854	$167,026,478	$187,606,681	$202,678,422	$199,375,479	$209,174,874	$196,657,889	$198,273,277	$179,490,047	$199,967,973	$2,230,843,677
39		True-Up Provision for the Month-Over/(Under) Recovery	14,020,095	10,729,671	2,739,239	36,864,634	(190,295,095)	24,306,225	39,687,550	38,285,768	42,077,840	20,235,511	15,789,199	(23,554,871)	30,885,767
40		Interest Provision for the Month	14,873	24,800	32,233	33,590	(2,684)	(11,712)	(11,556)	(7,859)	(4,032)	(1,183)	244	(701)	66,013
41		True-Up & Interest Prov. Beg of Period-Over/(Under) Recovery	58,082,532	67,277,289	73,191,550	71,122,810	103,180,822	(91,957,167)	(72,502,864)	(37,667,081)	(4,229,383)	33,004,214	48,398,332	59,347,564	58,082,532
42		Deferred True-up Beginning of Period - Over/(Under) Recovery [7]	(51,621,690)	(51,621,690)	(51,621,690)	(51,621,690)	(51,621,690)	(51,621,690)	(51,621,690)	(51,621,690)	(51,621,690)	(51,621,690)	(51,621,690)	(51,621,690)	(51,621,690)
43		Prior Period True-Up Collected/(Refunded) This Period	(4,840,211)	(4,840,211)	(4,840,211)	(4,840,211)	(4,840,211)	(4,840,211)	(4,840,211)	(4,840,211)	(4,840,211)	(4,840,211)	(4,840,211)	(4,840,211)	(58,082,532)
44		**End of Period Net True-up Amount Over/(Under) Recovery**	$15,655,598	$21,569,859	$19,501,119	$51,559,132	($143,578,857)	($124,124,555)	($89,288,771)	($55,851,073)	($18,617,476)	($3,223,359)	$7,725,873	($20,669,910)	($20,669,910)
45															
46															

47 [1] Actuals include various adjustments as noted on the A-Schedules

48 [2] Other Fuel Expense consists of nuclear fuel design software maintenance costs

49 [3] Prior Period 2019 Actual/Estimated True-up

50 [4] Generating Performance Incentive Factor is (($8,577,071/12) x 99.9280%) - See Order No. PSC-2019-0484-FOF-EI

51 [5] Jurisdictionalized Incentive Mechanism - FPL Portion is (($12,786,460/12) x 99.9280%) - See Order No. PSC-2019-0484-FOF-EI

52 [6] Approved in Order No. PSC-2020-0084-S-EI issued in Docket No. 20190061-EI on March 20, 2020

53 [7] 2019 Final True-up

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20200001-EI EXHIBIT: 12
PARTY: FLORIDA POWER & LIGHT COMPANY – DIRECT
DESCRIPTION: R.B.Deaton RBD-3

FOR THE ACTUAL/ESTIMATED PERIOD OF: JANUARY 2020 THROUGH DECEMBER 2020

(1)	(2)	(3)	(4)	(5)	(6)	(7)
Line No.	True Up Section	True Up Line	2020			
			Actual/Estimated	MCC	Difference	% Difference
1	**Fuel Costs & Net Power Transactions**	Fuel Cost of System Net Generation [1]	$2,396,688,611	$2,397,432,553	($743,942)	(0.0%)
2		Fuel Cost of Stratified Sales	($36,082,691)	($26,025,039)	($10,057,652)	38.6%
3		Rail Car Lease (Cedar Bay/ICL/SJRPP)	$2,083,460	$1,890,513	$192,948	10.2%
4		Fuel Cost of Power Sold (Per A6)	($50,569,119)	($47,254,029)	($3,315,090)	7.0%
5		Gains from Off-System Sales (Per A6)	($24,898,147)	($24,206,994)	($691,153)	2.9%
6		Fuel Cost of Purchased Power (Per A7)	$27,291,794	$27,339,062	($47,267)	(0.2%)
7		Energy Payments to Qualifying Facilities (Per A8)	$4,701,482	$4,451,007	$250,474	5.6%
8		Energy Cost of Economy Purchases (Per A9)	$10,530,786	$12,604,674	($2,073,888)	(16.5%)
9		Total Fuel Costs & Net Power Transactions	$2,329,746,176	$2,346,231,746	($16,485,570)	(0.7%)
10						
11	**Incremental Optimization Costs**	Incremental Personnel, Software, and Hardware Costs	$493,717	$472,570	$21,147	4.5%
12		Variable Power Plant O&M Attributable to Off-System Sales (Per A6)	$1,841,614	$1,758,319	$83,295	4.7%
13		Variable Power Plant O&M Avoided due to Economy Purchases (Per A9)	($240,352)	($293,339)	$52,987	(18.1%)
14		Total Incremental Optimization Costs	$2,094,979	$1,937,550	$157,428	8.1%
15						
16		Dodd Frank Fees	$399	$399	-	N/A
17						
18	**Adjustments to Fuel Cost**	Energy Imbalance Fuel Revenues	($395,022)	($128,037)	($266,984)	208.5%
19		Inventory Adjustments	$128,705	$37,749	$90,957	241.0%
20		Non Recoverable Oil/Tank Bottoms				N/A
21		Other O&M Expense	$579,829	$511,736	$68,094	13.3%
22		Adjusted Total Fuel Costs & Net Power Transactions	$2,332,155,067	$2,348,591,142	($16,436,075)	(0.7%)
23						
24	**kWh Sales**	Jurisdictional kWh Sales	111,535,152,471	110,663,397,794	871,754,677	0.8%
25		Sales for Resale (excluding Stratified Sales)	5,228,858,323	5,138,868,820	89,989,503	1.8%
26		Total Sales	116,764,010,794	115,802,266,614	961,744,180	0.8%
27						
28		Jurisdictional % of Total Sales	N/A	N/A		
29						
30	**True-Up Calculation**	Jurisdictional Fuel Revenues (Net of Revenue Taxes)	$2,250,056,998	$2,233,314,817	$16,742,181	0.7%
31		**Fuel Adjustment Revenues Not Applicable to Period**				
32		Prior Period True-Up (Collected)/Refunded This Period [3]	$58,082,532	$58,082,532	-	N/A
33		GPIF, Net of Revenue Taxes [4]	($8,570,896)	($8,570,896)	-	N/A
34		Incentive Mechanism, Net of Revenue Taxes [5]	($12,777,254)	($12,777,254)	-	N/A
35		Solar Together - Subscription Credit, Net of Revenue Taxes	($25,061,936)	($23,964,654)	($1,097,282)	4.6%
36		Jurisdictional Fuel Revenues Applicable to Period	$2,261,729,445	$2,246,084,545	$15,644,900	0.7%
37		Adjusted Total Fuel Costs & Net Power Transactions	$2,332,155,067	$2,348,591,142	($16,436,075)	(0.7%)
38		Jurisdictional Sales % of Total kWh Sales	N/A	N/A		
39		Juris. Total Fuel Costs & Net Power Transactions	$2,230,843,677	$2,246,084,545	($15,240,868)	(0.7%)
40		True-Up Provision for the Month-Over/(Under) Recovery	$30,885,767	-	$30,885,767	N/A
41		Interest Provision for the Month	$66,013	-	$66,013	N/A
42		True-Up & Interest Prov. Beg of Period-Over/(Under) Recovery	$58,082,532	$58,082,532	-	N/A
43		Deferred True-up Beginning of Period - Over/(Under) Recovery [7]	($51,621,690)	($51,621,690)	-	N/A
44		Prior Period True-Up Collected/(Refunded) This Period	($58,082,532)	($58,082,532)	-	N/A
45		End of Period Net True-up Amount Over/(Under) Recovery	($20,669,910)	($51,621,690)	$30,951,780	(60.0%)

46

47

48 [1] Actuals include various adjustments as noted on the A-Schedules

49 [2] Other Fuel Expense consists of nuclear fuel design software maintenance costs

50 [3] Prior Period 2019 Actual/Estimated True-up

51 [4] Generating Performance Incentive Factor is (($8,577,071/12) x 99.9280%) - See Order No. PSC-2019-0484-FOF-EI

52 [5] Jurisdictionalized Incentive Mechanism - FPL Portion is (($12,786,460/12) x 99.9280%) - See Order No. PSC-2019-0484-FOF-EI

53 [6] Approved in Order No. PSC-2020-0084-S-EI issued in Docket No. 20190061-EI on March 20, 2020

54 [7] 2019 Final True-up

55

56 Note: Totals may not add due to rounding.

57

58 ( ) Reflects Underrecovery

ESTIMATED FOR THE PERIOD OF: JANUARY 2020 THROUGH DECEMBER 2020

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
Line No.	Fuel Data Category	Fuel Type for Reporting	a-Jan - 2020	a-Feb - 2020	a-Mar - 2020	a-Apr - 2020	a-May - 2020	a-Jun - 2020	Jul - 2020	Aug - 2020	Sep - 2020	Oct - 2020	Nov - 2020	Dec - 2020	Total
1	As Burned Fuel Cost ($)	Heavy Oil	-	-	326,267	721,875	67,552	845,704	1,614,126	2,764,546	3,427,903	3,698,618	399,826	-	13,866,418
2		Light Oil	1,800,781	1,050,075	493,986	513,591	852,425	755,992	740,619	1,575,333	3,194,970	3,710,718	5,120	110,957	14,804,568
3		Coal	1,080,768	3,383,964	72,787	(365,042)	6,080,662	7,296,845	5,579,326	5,760,044	5,595,270	5,940,492	5,071,701	5,212,506	50,709,323
4		Gas	168,164,005	157,343,873	168,755,681	167,391,782	182,245,993	192,980,234	190,617,418	198,964,403	183,407,317	188,459,177	174,870,185	196,420,227	2,169,620,295
5		Nuclear	14,450,716	11,819,090	11,864,975	10,371,153	13,300,786	12,715,710	12,846,072	12,846,072	12,414,277	9,759,639	11,945,347	13,353,863	147,687,701
6		Total As Burned Fuel Cost ($)	185,496,269	173,597,002	181,513,695	178,633,359	202,547,418	214,594,487	211,397,561	221,910,398	208,039,737	211,568,645	192,292,179	215,097,553	2,396,688,304
7															
8	Net Generation (MWH)	Heavy Oil	-	-	2,540	5,632	506	6,575	12,605	21,904	30,123	32,534	3,284	-	115,705
9		Light Oil	13,565	7,882	4,066	3,454	7,107	6,159	3,538	7,798	19,130	24,185	32	450	97,367
10		Coal	42,211	102,345	2,973	(2,893)	210,104	202,232	184,644	193,318	189,556	203,664	171,897	177,176	1,677,228
11		Gas	6,250,937	6,404,503	7,444,497	7,971,058	7,504,257	8,911,477	9,141,070	9,247,598	8,337,628	8,113,742	6,182,213	6,083,496	91,592,476
12		Nuclear	2,672,915	2,211,688	2,190,766	2,029,719	2,648,301	2,548,740	2,523,628	2,523,628	2,439,064	1,963,720	2,357,448	2,603,851	28,713,467
13		Solar (3)	228,683	254,390	333,955	329,972	394,431	341,098	415,581	400,297	369,935	378,049	331,211	302,408	4,080,010
14		Total Net Generation (MWH)	9,208,311	8,980,808	9,978,797	10,336,943	10,764,707	12,016,282	12,281,066	12,394,543	11,385,436	10,715,894	9,046,085	9,167,380	126,276,252
15															
16	Fuel Burned (Units) (1)	Heavy Oil	-	-	4,470	9,890	922	11,590	22,114	37,875	51,055	55,087	5,955	-	198,959
17		Light Oil	16,543	10,095	5,011	5,490	8,953	7,554	9,192	19,665	44,142	52,522	58	1,253	180,477
18		Coal (2)	21,861	76,108	2,847	(24,090)	133,780	141,638	124,236	129,284	126,530	135,255	116,073	119,700	1,103,222
19		Gas	42,826,739	44,198,675	51,670,774	54,741,889	51,665,884	61,948,892	63,397,723	64,315,948	58,146,869	56,404,861	42,165,532	41,596,007	633,079,793
20		Nuclear	28,714,743	23,535,391	23,390,657	22,266,296	28,738,222	27,810,510	27,046,601	27,046,601	26,139,306	20,871,266	24,480,013	27,046,729	307,086,334
21															
22	Fuel Burned (MMBTU)	Heavy Oil	-	-	28,291	62,594	5,838	73,351	141,531	242,403	326,753	352,558	38,112	-	1,271,430
23		Light Oil	97,217	59,273	29,275	31,941	52,549	44,118	53,587	114,645	257,350	306,201	337	7,303	1,053,796
24		Coal	361,060	1,272,746	23,877	(139,859)	2,242,705	2,608,296	2,112,010	2,197,826	2,151,007	2,299,336	1,973,249	2,034,894	19,137,147
25		Gas	43,898,440	45,300,631	53,003,268	56,267,943	52,955,797	63,345,403	63,397,723	64,315,948	58,146,869	56,404,861	42,165,532	41,596,007	640,798,422
26		Nuclear	28,714,743	23,535,391	23,390,657	22,266,296	28,738,222	27,810,510	27,046,601	27,046,601	26,139,306	20,871,266	24,480,013	27,046,729	307,086,334
27		Total Fuel Burned (MMBTU)	73,071,460	70,168,041	76,475,368	78,488,915	83,995,111	93,881,677	92,751,452	93,917,423	87,021,285	80,234,222	68,657,243	70,684,933	969,347,129
28															
29	Cost of Fuel ($/Unit)	Heavy Oil	0.0000	0.0000	72.9904	72.9904	73.2347	72.9710	72.9904	72.9904	67.1412	67.1412	67.1412	0.0000	69.6948
30		Light Oil	108.8545	104.0193	98.5803	93.5503	95.2111	100.0784	80.5757	80.1098	72.3788	70.6513	88.5776	88.5776	82.0304
31		Coal	49.4387	44.4624	25.5635	15.1531	45.4526	51.5177	44.9091	44.5535	44.2210	43.9207	43.6939	43.5465	45.9647
32		Gas	3.9266	3.5599	3.2660	3.0578	3.5274	3.1152	3.0067	3.0935	3.1542	3.3412	4.1472	4.7221	3.4271
33		Nuclear	0.5033	0.5022	0.5073	0.4658	0.4628	0.4572	0.4750	0.4750	0.4749	0.4676	0.4880	0.4937	0.4809
34															
35	Generator Mix (%)	Heavy Oil	0.00%	0.00%	0.03%	0.05%	0.00%	0.05%	0.10%	0.18%	0.26%	0.30%	0.04%	0.00%	0.09%
36		Light Oil	0.15%	0.09%	0.04%	0.03%	0.07%	0.05%	0.03%	0.06%	0.17%	0.23%	0.00%	0.00%	0.08%
37		Coal	0.46%	1.14%	0.03%	(0.03%)	1.95%	1.68%	1.50%	1.56%	1.66%	1.90%	1.90%	1.93%	1.33%
38		Gas	67.88%	71.31%	74.60%	77.11%	69.71%	74.16%	74.43%	74.61%	73.23%	75.72%	68.34%	66.36%	72.53%
39		Nuclear	29.03%	24.63%	21.95%	19.64%	24.60%	21.21%	20.55%	20.36%	21.42%	18.33%	26.06%	28.40%	22.74%
40		Solar	2.48%	2.83%	3.35%	3.19%	3.66%	2.84%	3.38%	3.23%	3.25%	3.53%	3.66%	3.30%	3.23%
41		Total Generation Mix %	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
42															
43	Fuel Cost Per MMBTU ($/MMBTU)	Heavy Oil	0.0000	0.0000	11.5327	11.5327	11.5713	11.5296	11.4048	11.4048	10.4908	10.4908	10.4908	0.0000	10.9062
44		Light Oil	18.5233	17.7160	16.8737	16.0795	16.2216	17.1358	13.8209	13.7410	12.4149	12.1186	15.1934	15.1934	14.0488
45		Coal	2.9933	2.6588	3.0484	2.6101	2.7113	2.7976	2.6417	2.6208	2.6012	2.5836	2.5702	2.5616	2.6498
46		Gas	3.8308	3.4733	3.1839	2.9749	3.4415	3.0465	3.0067	3.0935	3.1542	3.3412	4.1472	4.7221	3.3858
47		Nuclear	0.5033	0.5022	0.5073	0.4658	0.4628	0.4572	0.4750	0.4750	0.4749	0.4676	0.4880	0.4937	0.4809
48															
49	BTU Burned Per KWH (BTU/KWH)	Heavy Oil	-	-	11,139	11,114	11,529	11,156	11,228	11,066	10,847	10,837	11,604	-	10,989
50		Light Oil	7,167	7,520	7,200	9,247	7,393	7,163	15,146	14,702	13,453	12,661	10,559	16,229	10,823
51		Coal	8,554	12,436	8,031	48,351	10,674	12,898	11,438	11,369	11,348	11,290	11,479	11,485	11,410
52		Gas	7,023	7,073	7,120	7,059	7,057	7,108	6,935	6,955	6,974	6,952	6,820	6,838	6,996
53		Nuclear	10,743	10,641	10,677	10,970	10,852	10,911	10,717	10,717	10,717	10,628	10,384	10,387	10,695

ESTIMATED FOR THE PERIOD OF: JANUARY 2020 THROUGH DECEMBER 2020

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
Line No.	Fuel Data Category	Fuel Type for Reporting	a-Jan - 2020	a-Feb - 2020	a-Mar - 2020	a-Apr - 2020	a-May - 2020	a-Jun - 2020	Jul - 2020	Aug - 2020	Sep - 2020	Oct - 2020	Nov - 2020	Dec - 2020	Total
54															
55	Cost if Generated (cents/KWH)	Heavy Oil	0.0000	0.0000	12.8457	12.8173	13.3401	12.8621	12.8052	12.6209	11.3797	11.3684	12.1738	0.0000	11.9843
56		Light Oil	13.2755	13.3221	12.1491	14.8682	11.9934	12.2744	20.9333	20.2018	16.7014	15.3431	16.0434	24.6572	15.2050
57		Coal	2.5604	3.3064	2.4483	12.6200	2.8941	3.6081	3.0217	2.9796	2.9518	2.9168	2.9504	2.9420	3.0234
58		Gas	2.6902	2.4568	2.2669	2.1000	2.4286	2.1655	2.0853	2.1515	2.1998	2.3227	2.8286	3.2287	2.3688
59		Nuclear	0.5406	0.5344	0.5416	0.5110	0.5022	0.4989	0.5090	0.5090	0.5090	0.4970	0.5067	0.5129	0.5143
60		Total Generated Fuel Cost per KWH (cents/KWH)	2.0144	1.9330	1.8190	1.7281	1.8816	1.7859	1.7213	1.7904	1.8272	1.9743	2.1257	2.3463	1.8980
61															
62															

63 (1) Fuel Units: Heavy Oil - BBLS, Light Oil - BBLS, Coal - TONS, Gas - MCF, Nuclear - MMBTU

64 (2) Scherer Coal Fuel Burned (Units) is reported in MMBTUs only

65 (3) Actuals do not include Martin 8 solar

ESTIMATED FOR THE PERIOD OF: JULY 2020 THROUGH DECEMBER 2020

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.	FCR - E-4 Schedule	Net Capability (MW)	Net Generation (MWH)	Capacity Factor (%)	Equivalent Availability Factor (%)	Net Output Factor (%)	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost ($)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel ($/Unit)
1	**Jul - 2020**												
2	Babcock Preserve PV Solar												
3	Solar		15,420				N/A	N/A	N/A	N/A	N/A	N/A	N/A
4	Plant Unit Info	74.5	15,420	27.8%	N/A	51.4%				N/A	N/A	N/A	
5	Babcock PV Solar												
6	Solar		14,422				N/A	N/A	N/A	N/A	N/A	N/A	N/A
7	Plant Unit Info	74.5	14,422	26.0%	N/A	41.6%				N/A	N/A	N/A	
8	Barefoot Bay PV Solar												
9	Solar		15,838				N/A	N/A	N/A	N/A	N/A	N/A	N/A
10	Plant Unit Info	74.5	15,838	28.6%	N/A	52.8%				N/A	N/A	N/A	
11	Blue Cypress PV Solar												
12	Solar		16,150				N/A	N/A	N/A	N/A	N/A	N/A	N/A
13	Plant Unit Info	74.5	16,150	29.1%	N/A	53.8%				N/A	N/A	N/A	
14	Blue Heron PV Solar												
15	Solar		15,420				N/A	N/A	N/A	N/A	N/A	N/A	N/A
16	Plant Unit Info	74.5	15,420	27.8%	N/A	51.4%				N/A	N/A	N/A	
17	Cattle Ranch PV Solar												
18	Solar		16,889				N/A	N/A	N/A	N/A	N/A	N/A	N/A
19	Plant Unit Info	74.5	16,889	30.5%	N/A	56.3%				N/A	N/A	N/A	
20	CCEC 3												
21	Light Oil		-				-	-	-	-	-	-	-
22	Gas		659,137				6,748	4,447,871	1,000,000	4,447,871	13,566,225	2.06	3.05
23	Plant Unit Info	1,308	659,137	67.7%	93.9%	67.7%	6,748			4,447,871	13,566,225	2.06	
24	Citrus PV Solar												
25	Solar		14,809				N/A	N/A	N/A	N/A	N/A	N/A	N/A
26	Plant Unit Info	74.5	14,809	26.7%	N/A	42.7%				N/A	N/A	N/A	
27	Coral Farms PV Solar												
28	Solar		16,719				N/A	N/A	N/A	N/A	N/A	N/A	N/A
29	Plant Unit Info	74.5	16,719	30.2%	N/A	55.7%				N/A	N/A	N/A	
30	Desoto Solar												
31	Solar		4,546				N/A	N/A	N/A	N/A	N/A	N/A	N/A
32	Plant Unit Info	25.0	4,546	24.4%	N/A	41.9%				N/A	N/A	N/A	
33	Echo River PV Solar												
34	Solar		19,942				N/A	N/A	N/A	N/A	N/A	N/A	N/A
35	Plant Unit Info	74.5	19,942	36.0%	N/A	61.7%				N/A	N/A	N/A	
36	Fort Myers GT												
37	Light Oil		-				-	-	-	-	-	-	-
38	Gas		-				-	-	-	-	-	-	0.00

ESTIMATED FOR THE PERIOD OF: JULY 2020 THROUGH DECEMBER 2020

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.	FCR - E-4 Schedule	Net Capability (MW)	Net Generation (MWH)	Capacity Factor (%)	Equivalent Availability Factor (%)	Net Output Factor (%)	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost ($)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel ($/Unit)
1	Plant Unit Info	0	-	N/A	N/A	N/A	-			-	-	-	
2	Fort Myers 2												
3	Gas		753,885				7,244	5,461,202	1,000,000	5,461,202	16,659,118	2.21	3.05
4	Plant Unit Info	1,730	753,885	58.6%	94.0%	58.6%	7,244			5,461,202	16,659,118	2.21	
5	Fort Myers 3A												
6	Light Oil		1,100				14,199	2,679	5,830,000	15,619	254,438	23.13	94.97
7	Gas						-	-	-	-	-	-	-
8	Plant Unit Info	164	1,100	0.9%	93.5%	67.1%	14,199			15,619	254,438	23.13	
9	Fort Myers 3B												
10	Light Oil		500				15,010	1,287	5,830,000	7,505	122,259	24.45	94.97
11	Gas						-	-	-	-	-	-	-
12	Plant Unit Info	168	500	0.4%	93.5%	59.5%	15,010			7,505	122,259	24.45	
13	Fort Myers 3C												
14	Light Oil		-				-	-	-	-	-	-	-
15	Gas		11,138				10,476	116,684	1,000,000	116,684	355,783	3.19	3.05
16	Plant Unit Info	219	11,138	6.8%	93.5%	92.5%	10,476			116,684	355,783	3.19	
17	Fort Myers 3D												
18	Light Oil		-				-	-	-	-	-	-	-
19	Gas		11,745				10,490	123,202	1,000,000	123,202	375,534	3.20	3.05
20	Plant Unit Info	219	11,745	7.2%	93.5%	92.5%	10,490			123,202	375,534	3.20	
21	Hammock PV Solar												
22	Solar		15,832				N/A	N/A	N/A	N/A	N/A	N/A	N/A
23	Plant Unit Info	74.5	15,832	28.6%	N/A	52.7%				N/A	N/A	N/A	
24	Hibiscus PV Solar												
25	Solar		15,689				N/A	N/A	N/A	N/A	N/A	N/A	N/A
26	Plant Unit Info	74.5	15,689	28.3%	N/A	52.3%				N/A	N/A	N/A	
27	Horizon PV Solar												
28	Solar		16,746				N/A	N/A	N/A	N/A	N/A	N/A	N/A
29	Plant Unit Info	74.5	16,746	30.2%	N/A	55.8%				N/A	N/A	N/A	
30	Indiantown FPL												
31	Coal		-					-	-	-	-	-	-
32	Plant Unit Info	0	-	0.0%	N/A	0.0%	-			-	-	-	
33	Indian River PV Solar												
34	Solar		16,135				N/A	N/A	N/A	N/A	N/A	N/A	N/A
35	Plant Unit Info	74.5	16,135	29.1%	N/A	53.7%				N/A	N/A	N/A	
36	Interstate PV Solar												
37	Solar		15,280				N/A	N/A	N/A	N/A	N/A	N/A	N/A
38	Plant Unit Info	74.5	15,280	27.6%	N/A	50.9%				N/A	N/A	N/A	

ESTIMATED FOR THE PERIOD OF: JULY 2020 THROUGH DECEMBER 2020

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.	FCR - E-4 Schedule	Net Capability (MW)	Net Generation (MWH)	Capacity Factor (%)	Equivalent Availability Factor (%)	Net Output Factor (%)	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost ($)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel ($/Unit)
1	Lauderdale GT												
2	Light Oil		-				-	-	-	-	-	-	-
3	Gas		-				-	-	-	-	-	-	-
4	Plant Unit Info	0	-	N/A	N/A	N/A	-			-	-	-	
5	Lauderdale 6A												
6	Light Oil		-				-	-	-	-	-	-	-
7	Gas		15,215				10,489	159,596	1,000,000	159,596	486,765	3.20	3.05
8	Plant Unit Info	216	15,215	9.5%	93.5%	92.7%	10,489			159,596	486,765	3.20	
9	Lauderdale 6B												
10	Light Oil		-				-	-	-	-	-	-	-
11	Gas		17,618				10,494	184,875	1,000,000	184,875	563,927	3.20	3.05
12	Plant Unit Info	216	17,618	11.0%	93.5%	92.7%	10,494			184,875	563,927	3.20	
13	Lauderdale 6C												
14	Gas		-				-	-	-	-	-	-	-
15	Plant Unit Info	0	-	N/A	N/A	N/A	-			-	-	-	
16	Lauderdale 6D												
17	Light Oil		458				16,749	1,316	5,830,000	7,671	91,641	20.01	69.65
18	Gas		-				-	-	-	-	-	-	-
19	Plant Unit Info	216	458	0.3%	93.5%	41.6%	16,749			7,671	91,641	20.01	
20	Lauderdale 6E												
21	Light Oil		1,480				15,400	3,909	5,830,000	22,792	272,282	18.40	69.65
22	Gas		-				-	-	-	-	-	-	-
23	Plant Unit Info	216	1,480	0.9%	93.5%	48.9%	15,400			22,792	272,282	18.40	
24	Loggerhead PV Solar												
25	Solar		16,009				N/A	N/A	N/A	N/A	N/A	N/A	N/A
26	Plant Unit Info	74.5	16,009	28.9%	N/A	53.3%				N/A	N/A	N/A	
27	Manatee 1												
28	Heavy Oil		6,330					11,106	6,400,000	71,078	810,627	12.81	72.99
29	Gas		64,155				11,228	720,337	1,000,000	720,337	2,119,220	3.30	2.94
30	Plant Unit Info	789	70,485	12.0%	96.2%	23.1%	11,228			791,415	2,929,847	4.16	
31	Manatee 2												
32	Heavy Oil		6,275					11,008	6,400,000	70,453	803,499	12.80	72.99
33	Gas		109,292				11,228	1,227,101	1,000,000	1,227,101	3,610,693	3.30	2.94
34	Plant Unit Info	789	115,567	19.7%	96.2%	19.7%	11,228			1,297,554	4,414,192	3.82	
35	Manatee 3												
36	Gas		428,905				7,391	3,169,914	1,000,000	3,169,914	9,309,430	2.17	2.94
37	Plant Unit Info	1,223	428,905	47.1%	94.1%	82.7%	7,391			3,169,914	9,309,430	2.17	
38	Manatee PV Solar												

ESTIMATED FOR THE PERIOD OF: JULY 2020 THROUGH DECEMBER 2020

(1) Line No.	(2) FCR - E-4 Schedule	(3) Net Capability (MW)	(4) Net Generation (MWH)	(5) Capacity Factor (%)	(6) Equivalent Availability Factor (%)	(7) Net Output Factor (%)	(8) Avg Net Heat Rate (BTU/KWH)	(9) Fuel Burned (Units)	(10) Fuel Heat Value (BTU/unit)	(11) Fuel Burned (MMBTU)	(12) As Burned Fuel Cost ($)	(13) Fuel Cost per KWH (cents/KWH)	(14) Cost of Fuel ($/Unit)
1	Solar		14,533				N/A	N/A	N/A	N/A	N/A	N/A	N/A
2	Plant Unit Info	74.5	14,533	26.2%	N/A	42.0%				N/A	N/A	N/A	
3	Martin 3												
4	Gas		188,131				7,520	1,414,747	1,000,000	1,414,747	4,242,118	2.25	3.00
5	Plant Unit Info	464	188,131	54.5%	93.9%	54.5%	7,520			1,414,747	4,242,118	2.25	
6	Martin 4												
7	Gas		189,364				7,529	1,425,712	1,000,000	1,425,712	4,276,276	2.26	3.00
8	Plant Unit Info	464	189,364	54.9%	94.0%	54.9%	7,529			1,425,712	4,276,276	2.26	
9	Martin 8 Solar												
10	Solar		12,679				N/A	N/A	N/A	N/A	N/A	N/A	N/A
11	Plant Unit Info	75.0	12,679	22.7%	N/A	36.4%				N/A	N/A	N/A	
12	Martin 8												
13	Light Oil		-				-	-	-	-	-	-	-
14	Gas		314,873				7,589	2,389,551	1,000,000	2,389,551	7,219,593	2.29	3.02
15	Plant Unit Info	1,218	314,873	34.8%	94.0%	83.4%	7,589			2,389,551	7,219,593	2.29	
16	Miami-Dade PV Solar												
17	Solar		14,897				N/A	N/A	N/A	N/A	N/A	N/A	N/A
18	Plant Unit Info	74.5	14,897	26.9%	N/A	49.6%				N/A	N/A	N/A	
19	Northern Preserve PV Solar												
20	Solar		13,402				N/A	N/A	N/A	N/A	N/A	N/A	N/A
21	Plant Unit Info	74.5	13,402	24.2%	N/A	44.6%				N/A	N/A	N/A	
22	Okechobee 1												
23	Light Oil		-				-	-	-	-	-	-	-
24	Gas		1,094,999				6,266	6,861,565	1,000,000	6,861,565	20,838,104	1.90	3.04
25	Plant Unit Info	1,618	1,094,999	91.0%	96.7%	91.0%	6,266			6,861,565	20,838,104	1.90	
26	Okeechobee PV Solar												
27	Solar		16,177				N/A	N/A	N/A	N/A	N/A	N/A	N/A
28	Plant Unit Info	74.5	16,177	29.2%	N/A	53.9%				N/A	N/A	N/A	
29	PEEC												
30	Light Oil		-				-	-	-	-	-	-	-
31	Gas		835,033				6,351	5,303,361	1,000,000	5,303,361	16,176,473	1.94	3.05
32	Plant Unit Info	1,254	835,033	89.5%	93.9%	89.5%	6,351			5,303,361	16,176,473	1.94	
33	Pioneer Trail PV Solar												
34	Solar		15,188				N/A	N/A	N/A	N/A	N/A	N/A	N/A
35	Plant Unit Info	74.5	15,188	27.4%	N/A	50.6%				N/A	N/A	N/A	
36	Riviera 5												
37	Light Oil		-				-	-	-	-	-	-	-
38	Gas		740,699				6,694	4,958,316	1,000,000	4,958,316	15,058,135	2.03	3.04

ESTIMATED FOR THE PERIOD OF: JULY 2020 THROUGH DECEMBER 2020

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.	FCR - E-4 Schedule	Net Capability (MW)	Net Generation (MWH)	Capacity Factor (%)	Equivalent Availability Factor (%)	Net Output Factor (%)	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost ($)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel ($/Unit)
1	Plant Unit Info	1,308	740,699	76.1%	93.9%	76.1%	6,694			4,958,316	15,058,135	2.03	
2	Sanford 4												
3	Gas		437,402				7,225	3,160,217	1,000,000	3,160,217	9,638,467	2.20	3.05
4	Plant Unit Info	1,147	437,402	51.3%	94.0%	51.3%	7,225			3,160,217	9,638,467	2.20	
5	Sanford 5												
6	Gas		479,371				7,087	3,397,537	1,000,000	3,397,537	10,363,232	2.16	3.05
7	Plant Unit Info	1,147	479,371	56.2%	94.0%	56.2%	7,087			3,397,537	10,363,232	2.16	
8	Scherer 4												
9	Coal		184,644					124,236	17,000,000	2,112,010	5,579,326	3.02	44.91
10	Plant Unit Info	636	184,644	39.0%	94.8%	39.0%	11,438			2,112,010	5,579,326	3.02	
11	Southfork PV Solar												
12	Solar		18,794				N/A	N/A	N/A	N/A	N/A	N/A	N/A
13	Plant Unit Info	74.5	18,794	33.9%	N/A	62.6%				N/A	N/A	N/A	
14	Space Coast												
15	Solar		1,555				N/A	N/A	N/A	N/A	N/A	N/A	N/A
16	Plant Unit Info	10.0	1,555	20.9%	N/A	33.4%				N/A	N/A	N/A	
17	St Lucie 1												
18	Nuclear		711,586					7,514,275	1,000,000	7,514,275	3,625,638	0.51	0.48
19	Plant Unit Info	981	711,586	97.5%	97.5%	97.5%	10,560			7,514,275	3,625,638	0.51	
20	St Lucie 2												
21	Nuclear		609,292					6,394,944	1,000,000	6,394,944	2,775,405	0.46	0.43
22	Plant Unit Info	840	609,292	97.5%	97.5%	97.5%	10,496			6,394,944	2,775,405	0.46	
23	Sunshine Gateway PV Solar												
24	Solar		16,190				N/A	N/A	N/A	N/A	N/A	N/A	N/A
25	Plant Unit Info	74.5	16,190	29.2%	N/A	50.1%				N/A	N/A	N/A	
26	Sweet Bay PV Solar												
27	Solar		13,905				N/A	N/A	N/A	N/A	N/A	N/A	N/A
28	Plant Unit Info	74.5	13,905	25.1%	N/A	N/A				N/A	N/A	N/A	
29	Turkey Point 3												
30	Nuclear		607,178					6,568,699	1,000,000	6,568,699	3,162,001	0.52	0.48
31	Plant Unit Info	837	607,178	97.5%	97.5%	97.5%	10,818			6,568,699	3,162,001	0.52	
32	Turkey Point 4												
33	Nuclear		595,572					6,568,683	1,000,000	6,568,683	3,283,028	0.55	0.50
34	Plant Unit Info	821	595,572	97.5%	96.9%	97.5%	11,029			6,568,683	3,283,028	0.55	
35	Turkey Point 5												
36	Light Oil		-				-	-	-	-	-	-	-
37	Gas		495,815				7,142	3,540,972	1,000,000	3,540,972	10,800,017	2.18	3.05
38	Plant Unit Info	1,256	495,815	53.1%	94.0%	53.1%	7,142			3,540,972	10,800,017	2.18	

ESTIMATED FOR THE PERIOD OF: JULY 2020 THROUGH DECEMBER 2020

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.	FCR - E-4 Schedule	Net Capability (MW)	Net Generation (MWH)	Capacity Factor (%)	Equivalent Availability Factor (%)	Net Output Factor (%)	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost ($)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel ($/Unit)
1	Twin Lakes PV Solar												
2	Solar		16,435				N/A	N/A	N/A	N/A	N/A	N/A	N/A
3	Plant Unit Info	74.5	16,435	29.7%	N/A	54.7%				N/A	N/A	N/A	
4	WCEC 01												
5	Light Oil		-				-	-	-	-	-	-	-
6	Gas		795,447				6,636	5,278,296	1,000,000	5,278,296	15,474,342	1.95	2.93
7	Plant Unit Info	1,223	795,447	87.4%	93.9%	87.4%	6,636			5,278,296	15,474,342	1.95	
8	WCEC 02												
9	Light Oil		-				-	-	-	-	-	-	-
10	Gas		725,275				6,682	4,845,994	1,000,000	4,845,994	14,207,653	1.96	2.93
11	Plant Unit Info	1,223	725,275	79.7%	86.4%	79.7%	6,682			4,845,994	14,207,653	1.96	
12	WCEC 03												
13	Light Oil		-				-	-	-	-	-	-	-
14	Gas		773,571				6,736	5,210,673	1,000,000	5,210,673	15,276,312	1.97	2.93
15	Plant Unit Info	1,211	773,571	85.9%	93.9%	85.9%	6,736			5,210,673	15,276,312	1.97	
16	Wildflower PV Solar												
17	Solar		15,980				N/A	N/A	N/A	N/A	N/A	N/A	N/A
18	Plant Unit Info	74.5	15,980	28.8%	N/A	53.2%				N/A	N/A	N/A	
19	System Totals												
20	Plant Unit Info	27,094	12,281,066				7,552			92,751,452	211,397,561	1.72	
21													
22													
23													
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ESTIMATED FOR THE PERIOD OF: JULY 2020 THROUGH DECEMBER 2020

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.	FCR - E-4 Schedule	Net Capability (MW)	Net Generation (MWH)	Capacity Factor (%)	Equivalent Availability Factor (%)	Net Output Factor (%)	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost ($)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel ($/Unit)
1	**Aug - 2020**												
2	Babcock Preserve PV Solar												
3	Solar		14,937				N/A	N/A	N/A	N/A	N/A	N/A	N/A
4	Plant Unit Info	74.5	14,937	27.0%	N/A	49.8%				N/A	N/A	N/A	
5	Babcock PV Solar												
6	Solar		14,342				N/A	N/A	N/A	N/A	N/A	N/A	N/A
7	Plant Unit Info	74.5	14,342	25.9%	N/A	41.4%				N/A	N/A	N/A	
8	Barefoot Bay PV Solar												
9	Solar		15,018				N/A	N/A	N/A	N/A	N/A	N/A	N/A
10	Plant Unit Info	74.5	15,018	27.1%	N/A	50.0%				N/A	N/A	N/A	
11	Blue Cypress PV Solar												
12	Solar		15,243				N/A	N/A	N/A	N/A	N/A	N/A	N/A
13	Plant Unit Info	74.5	15,243	27.5%	N/A	50.8%				N/A	N/A	N/A	
14	Blue Heron PV Solar												
15	Solar		14,937				N/A	N/A	N/A	N/A	N/A	N/A	N/A
16	Plant Unit Info	74.5	14,937	27.0%	N/A	49.8%				N/A	N/A	N/A	
17	Cattle Ranch PV Solar												
18	Solar		15,651				N/A	N/A	N/A	N/A	N/A	N/A	N/A
19	Plant Unit Info	74.5	15,651	28.2%	N/A	52.1%				N/A	N/A	N/A	
20	CCEC 3												
21	Light Oil		-				-	-	-	-	-	-	-
22	Gas		694,408				6,720	4,666,537	1,000,000	4,666,537	14,657,593	2.11	3.14
23	Plant Unit Info	1,308	694,408	71.4%	93.9%	71.4%	6,720			4,666,537	14,657,593	2.11	
24	Citrus PV Solar												
25	Solar		14,611				N/A	N/A	N/A	N/A	N/A	N/A	N/A
26	Plant Unit Info	74.5	14,611	26.4%	N/A	45.2%				N/A	N/A	N/A	
27	Coral Farms PV Solar												
28	Solar		16,129				N/A	N/A	N/A	N/A	N/A	N/A	N/A
29	Plant Unit Info	74.5	16,129	29.1%	N/A	53.7%				N/A	N/A	N/A	
30	Desoto Solar												
31	Solar		4,326				N/A	N/A	N/A	N/A	N/A	N/A	N/A
32	Plant Unit Info	25.0	4,326	23.3%	N/A	39.9%				N/A	N/A	N/A	
33	Echo River PV Solar												
34	Solar		18,710				N/A	N/A	N/A	N/A	N/A	N/A	N/A
35	Plant Unit Info	74.5	18,710	33.8%	N/A	62.3%				N/A	N/A	N/A	
36	Fort Myers GT												
37	Light Oil		-				-	-	-	-	-	-	-
38	Gas		-				-	-	-	-	-	-	-

ESTIMATED FOR THE PERIOD OF: JULY 2020 THROUGH DECEMBER 2020

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.	FCR - E-4 Schedule	Net Capability (MW)	Net Generation (MWH)	Capacity Factor (%)	Equivalent Availability Factor (%)	Net Output Factor (%)	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost ($)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel ($/Unit)
1	Plant Unit Info	0	-	N/A	N/A	N/A	-			-	-	-	
2	Fort Myers 2												
3	Gas		764,040				7,247	5,536,713	1,000,000	5,536,713	17,389,904	2.28	3.14
4	Plant Unit Info	1,730	764,040	59.4%	94.0%	59.4%	7,247			5,536,713	17,389,904	2.28	
5	Fort Myers 3A												
6	Light Oil		1,733				14,290	4,248	5,830,000	24,765	403,429	23.28	94.97
7	Gas		-				-	-	-	-	-	-	-
8	Plant Unit Info	164	1,733	1.4%	93.5%	66.0%	14,290			24,765	403,429	23.28	
9	Fort Myers 3B												
10	Light Oil		1,513				14,936	3,876	5,830,000	22,598	368,128	24.33	94.97
11	Gas		-				-	-	-	-	-	-	-
12	Plant Unit Info	168	1,513	1.2%	93.5%	60.0%	14,936			22,598	368,128	24.33	
13	Fort Myers 3C												
14	Light Oil		-				-	-	-	-	-	-	-
15	Gas		17,820				10,470	186,575	1,000,000	186,575	585,838	3.29	3.14
16	Plant Unit Info	219	17,820	10.9%	93.5%	92.5%	10,470			186,575	585,838	3.29	
17	Fort Myers 3D												
18	Light Oil		-				-	-	-	-	-	-	-
19	Gas		16,605				10,487	174,140	1,000,000	174,140	546,396	3.29	3.14
20	Plant Unit Info	219	16,605	10.2%	93.5%	92.5%	10,487			174,140	546,396	3.29	
21	Hammock PV Solar												
22	Solar		15,279				N/A	N/A	N/A	N/A	N/A	N/A	N/A
23	Plant Unit Info	74.5	15,279	27.6%	N/A	50.9%				N/A	N/A	N/A	
24	Hibiscus PV Solar												
25	Solar		15,424				N/A	N/A	N/A	N/A	N/A	N/A	N/A
26	Plant Unit Info	74.5	15,424	27.8%	N/A	51.4%				N/A	N/A	N/A	
27	Horizon PV Solar												
28	Solar		16,140				N/A	N/A	N/A	N/A	N/A	N/A	N/A
29	Plant Unit Info	74.5	16,140	29.1%	N/A	53.8%				N/A	N/A	N/A	
30	Indiantown FPL												
31	Coal		-					-	-	-	-	-	-
32	Plant Unit Info	0	-	N/A	N/A	N/A	-			-	-	-	
33	Indian River PV Solar												
34	Solar		15,230				N/A	N/A	N/A	N/A	N/A	N/A	N/A
35	Plant Unit Info	74.5	15,230	27.5%	N/A	50.7%				N/A	N/A	N/A	
36	Interstate PV Solar												
37	Solar		15,104				N/A	N/A	N/A	N/A	N/A	N/A	N/A
38	Plant Unit Info	74.5	15,104	27.3%	N/A	50.3%				N/A	N/A	N/A	

ESTIMATED FOR THE PERIOD OF: JULY 2020 THROUGH DECEMBER 2020

(1) Line No.	(2) FCR - E-4 Schedule	(3) Net Capability (MW)	(4) Net Generation (MWH)	(5) Capacity Factor (%)	(6) Equivalent Availability Factor (%)	(7) Net Output Factor (%)	(8) Avg Net Heat Rate (BTU/KWH)	(9) Fuel Burned (Units)	(10) Fuel Heat Value (BTU/unit)	(11) Fuel Burned (MMBTU)	(12) As Burned Fuel Cost ($)	(13) Fuel Cost per KWH (cents/KWH)	(14) Cost of Fuel ($/Unit)
1	Lauderdale GT												
2	Light Oil		-				-	-	-	-	-	-	-
3	Gas		-				-	-	-	-	-	-	-
4	Plant Unit Info	0	-	N/A	N/A	N/A	-			-	-	-	
5	Lauderdale 6A												
6	Light Oil		-				-	-	-	-	-	-	-
7	Gas		21,622				10,494	226,905	1,000,000	226,905	712,452	3.30	3.14
8	Plant Unit Info	216	21,622	13.5%	93.5%	92.7%	10,494			226,905	712,452	3.30	
9	Lauderdale 6B												
10	Light Oil		-				-	-	-	-	-	-	-
11	Gas		21,421				10,497	224,849	1,000,000	224,849	705,891	3.30	3.14
12	Plant Unit Info	216	21,421	13.3%	93.5%	92.7%	10,497			224,849	705,891	3.30	
13	Lauderdale 6C												
14	Light Oil		1,195				14,315	2,934	5,830,000	17,106	204,354	17.10	69.65
15	Gas		-				-	-	-	-	-	-	-
16	Plant Unit Info	216	1,195	0.7%	93.5%	55.1%	14,315			17,106	204,354	17.10	
17	Lauderdale 6D												
18	Light Oil		2,085				14,625	5,231	5,830,000	30,494	364,292	17.47	69.65
19	Gas		-				-	-	-	-	-	-	-
20	Plant Unit Info	216	2,085	1.3%	93.5%	53.6%	14,625			30,494	364,292	17.47	
21	Lauderdale 6E												
22	Light Oil		1,272				15,473	3,376	5,830,000	19,682	235,128	18.48	69.65
23	Gas		-				-	-	-	-	-	-	-
24	Plant Unit Info	216	1,272	0.8%	93.5%	49.1%	15,473			19,682	235,128	18.48	
25	Loggerhead PV Solar												
26	Solar		15,258				N/A	N/A	N/A	N/A	N/A	N/A	N/A
27	Plant Unit Info	74.5	15,258	27.5%	N/A	50.8%				N/A	N/A	N/A	
28	Manatee 1												
29	Heavy Oil		12,097					20,757	6,400,000	132,847	1,515,087	12.52	72.99
30	Gas		116,927				10,982	1,284,107	1,000,000	1,284,107	3,872,233	3.31	3.02
31	Plant Unit Info	789	129,024	22.0%	96.2%	22.0%	10,982			1,416,954	5,387,320	4.18	
32	Manatee 2												
33	Heavy Oil		9,808					17,118	6,400,000	109,556	1,249,459	12.74	72.99
34	Gas		107,015				11,170	1,195,400	1,000,000	1,195,400	3,615,655	3.38	3.02
35	Plant Unit Info	789	116,823	19.9%	96.2%	19.9%	11,170			1,304,956	4,865,114	4.16	
36	Manatee 3												
37	Gas		354,466				7,445	2,638,988	1,000,000	2,638,988	7,966,772	2.25	3.02
38	Plant Unit Info	1,223	354,466	39.0%	94.1%	85.5%	7,445			2,638,988	7,966,772	2.25	

ESTIMATED FOR THE PERIOD OF: JULY 2020 THROUGH DECEMBER 2020

(1) Line No.	(2) FCR - E-4 Schedule	(3) Net Capability (MW)	(4) Net Generation (MWH)	(5) Capacity Factor (%)	(6) Equivalent Availability Factor (%)	(7) Net Output Factor (%)	(8) Avg Net Heat Rate (BTU/KWH)	(9) Fuel Burned (Units)	(10) Fuel Heat Value (BTU/unit)	(11) Fuel Burned (MMBTU)	(12) As Burned Fuel Cost ($)	(13) Fuel Cost per KWH (cents/KWH)	(14) Cost of Fuel ($/Unit)
1	Manatee PV Solar												
2	Solar		14,390				N/A	N/A	N/A	N/A	N/A	N/A	N/A
3	Plant Unit Info	74.5	14,390	26.0%	N/A	44.5%				N/A	N/A	N/A	
4	Martin 3												
5	Gas		183,663				7,539	1,384,614	1,000,000	1,384,614	4,280,580	2.33	3.09
6	Plant Unit Info	464	183,663	53.2%	93.9%	53.2%	7,539			1,384,614	4,280,580	2.33	
7	Martin 4												
8	Gas		190,017				7,531	1,431,004	1,000,000	1,431,004	4,416,665	2.32	3.09
9	Plant Unit Info	464	190,017	55.0%	94.0%	55.0%	7,531			1,431,004	4,416,665	2.32	
10	Martin 8 Solar												
11	Solar		11,873				N/A	N/A	N/A	N/A	N/A	N/A	N/A
12	Plant Unit Info	75.0	11,873	21.3%	N/A	39.3%				N/A	N/A	N/A	
13	Martin 8												
14	Light Oil		-				-	-	-	-	-	-	-
15	Gas		319,118				7,617	2,430,725	1,000,000	2,430,725	7,567,813	2.37	3.11
16	Plant Unit Info	1,218	319,118	35.2%	94.0%	83.2%	7,617			2,430,725	7,567,813	2.37	
17	Miami-Dade PV Solar												
18	Solar		14,745				N/A	N/A	N/A	N/A	N/A	N/A	N/A
19	Plant Unit Info	74.5	14,745	26.6%	N/A	49.1%				N/A	N/A	N/A	
20	Northern Preserve PV Solar												
21	Solar		12,982				N/A	N/A	N/A	N/A	N/A	N/A	N/A
22	Plant Unit Info	74.5	12,982	23.4%	N/A	43.2%				N/A	N/A	N/A	
23	Okechobee 1												
24	Light Oil		-				-	-	-	-	-	-	-
25	Gas		1,093,129				6,267	6,851,087	1,000,000	6,851,087	21,405,461	1.96	3.12
26	Plant Unit Info	1,618	1,093,129	90.8%	96.7%	90.8%	6,267			6,851,087	21,405,461	1.96	
27	Okeechobee PV Solar												
28	Solar		15,842				N/A	N/A	N/A	N/A	N/A	N/A	N/A
29	Plant Unit Info	74.5	15,842	28.6%	N/A	52.8%				N/A	N/A	N/A	
30	PEEC												
31	Light Oil		-				-	-	-	-	-	-	-
32	Gas		839,707				6,347	5,329,488	1,000,000	5,329,488	16,740,738	1.99	3.14
33	Plant Unit Info	1,254	839,707	90.0%	93.9%	90.0%	6,347			5,329,488	16,740,738	1.99	
34	Pioneer Trail PV Solar												
35	Solar		15,069				N/A	N/A	N/A	N/A	N/A	N/A	N/A
36	Plant Unit Info	74.5	15,069	27.2%	N/A	50.2%				N/A	N/A	N/A	
37	Riviera 5												
38	Light Oil		-				-	-	-	-	-	-	-

ESTIMATED FOR THE PERIOD OF: JULY 2020 THROUGH DECEMBER 2020

(1) Line No.	(2) FCR - E-4 Schedule	(3) Net Capability (MW)	(4) Net Generation (MWH)	(5) Capacity Factor (%)	(6) Equivalent Availability Factor (%)	(7) Net Output Factor (%)	(8) Avg Net Heat Rate (BTU/KWH)	(9) Fuel Burned (Units)	(10) Fuel Heat Value (BTU/unit)	(11) Fuel Burned (MMBTU)	(12) As Burned Fuel Cost ($)	(13) Fuel Cost per KWH (cents/KWH)	(14) Cost of Fuel ($/Unit)
1	Gas		798,917				6,650	5,312,879	1,000,000	5,312,879	16,599,518	2.08	3.12
2	Plant Unit Info	1,308	798,917	82.1%	93.9%	82.1%	6,650			5,312,879	16,599,518	2.08	
3	Sanford 4												
4	Gas		441,739				7,220	3,189,224	1,000,000	3,189,224	10,015,513	2.27	3.14
5	Plant Unit Info	1,147	441,739	51.8%	94.0%	51.8%	7,220			3,189,224	10,015,513	2.27	
6	Sanford 5												
7	Gas		473,562				7,085	3,355,036	1,000,000	3,355,036	10,535,562	2.22	3.14
8	Plant Unit Info	1,147	473,562	55.5%	94.0%	55.5%	7,085			3,355,036	10,535,562	2.22	
9	Scherer 4												
10	Coal		193,318					129,284	17,000,000	2,197,826	5,760,044	2.98	44.55
11	Plant Unit Info	636	193,318	40.9%	94.8%	40.9%	11,369			2,197,826	5,760,044	2.98	
12	Southfork PV Solar												
13	Solar		18,357				N/A	N/A	N/A	N/A	N/A	N/A	N/A
14	Plant Unit Info	74.5	18,357	33.1%	N/A	61.1%				N/A	N/A	N/A	
15	Space Coast												
16	Solar		1,545				N/A	N/A	N/A	N/A	N/A	N/A	N/A
17	Plant Unit Info	10.0	1,545	20.8%	N/A	38.3%				N/A	N/A	N/A	
18	St Lucie 1												
19	Nuclear		711,586					7,514,275	1,000,000	7,514,275	3,625,638	0.51	0.48
20	Plant Unit Info	981	711,586	97.5%	97.5%	97.5%	10,560			7,514,275	3,625,638	0.51	
21	St Lucie 2												
22	Nuclear		609,292					6,394,944	1,000,000	6,394,944	2,775,405	0.46	0.43
23	Plant Unit Info	840	609,292	97.5%	97.5%	97.5%	10,496			6,394,944	2,775,405	0.46	
24	Sunshine Gateway PV Solar												
25	Solar		15,292				N/A	N/A	N/A	N/A	N/A	N/A	N/A
26	Plant Unit Info	74.5	15,292	27.6%	N/A	50.9%				N/A	N/A	N/A	
27	Sweet Bay PV Solar												
28	Solar		13,274				N/A	N/A	N/A	N/A	N/A	N/A	N/A
29	Plant Unit Info	74.5	13,274	24.0%	N/A	N/A				N/A	N/A	N/A	
30	Turkey Point 3												
31	Nuclear		607,178					6,568,699	1,000,000	6,568,699	3,162,001	0.52	0.48
32	Plant Unit Info	837	607,178	97.5%	97.5%	97.5%	10,818			6,568,699	3,162,001	0.52	
33	Turkey Point 4												
34	Nuclear		595,572					6,568,683	1,000,000	6,568,683	3,283,028	0.55	0.50
35	Plant Unit Info	821	595,572	97.5%	96.9%	97.5%	11,029			6,568,683	3,283,028	0.55	
36	Turkey Point 5												
37	Light Oil		-				-	-	-	-	-	-	-
38	Gas		494,570				7,144	3,533,267	1,000,000	3,533,267	11,094,141	2.24	3.14

ESTIMATED FOR THE PERIOD OF: JULY 2020 THROUGH DECEMBER 2020

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.	FCR - E-4 Schedule	Net Capability (MW)	Net Generation (MWH)	Capacity Factor (%)	Equivalent Availability Factor (%)	Net Output Factor (%)	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost ($)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel ($/Unit)
1	Plant Unit Info	1,256	494,570	52.9%	94.0%	52.9%	7,144			3,533,267	11,094,141	2.24	
2	Twin Lakes PV Solar												
3	Solar		15,230				N/A	N/A	N/A	N/A	N/A	N/A	N/A
4	Plant Unit Info	74.5	15,230	27.5%	N/A	50.7%				N/A	N/A	N/A	
5	WCEC 01												
6	Light Oil		-				-	-	-	-	-	-	-
7	Gas		796,367				6,637	5,285,550	1,000,000	5,285,550	15,913,246	2.00	3.01
8	Plant Unit Info	1,223	796,367	87.5%	93.9%	87.5%	6,637			5,285,550	15,913,246	2.00	
9	WCEC 02												
10	Light Oil		-				-	-	-	-	-	-	-
11	Gas		784,776				6,678	5,240,668	1,000,000	5,240,668	15,778,462	2.01	3.01
12	Plant Unit Info	1,223	784,776	86.3%	93.9%	86.2%	6,678			5,240,668	15,778,462	2.01	
13	WCEC 03												
14	Light Oil		-				-	-	-	-	-	-	-
15	Gas		717,708				6,741	4,838,192	1,000,000	4,838,192	14,563,970	2.03	3.01
16	Plant Unit Info	1,211	717,708	79.7%	87.4%	79.7%	6,741			4,838,192	14,563,970	2.03	
17	Wildflower PV Solar												
18	Solar		15,359				N/A	N/A	N/A	N/A	N/A	N/A	N/A
19	Plant Unit Info	74.5	15,359	27.7%	N/A	51.2%				N/A	N/A	N/A	
20	System Totals												
21	Plant Unit Info	27,310	12,394,543				7,577			93,917,423	221,910,398	1.79	
22													
23													
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ESTIMATED FOR THE PERIOD OF: JULY 2020 THROUGH DECEMBER 2020

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.	FCR - E-4 Schedule	Net Capability (MW)	Net Generation (MWH)	Capacity Factor (%)	Equivalent Availability Factor (%)	Net Output Factor (%)	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost ($)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel ($/Unit)
1	**Sep - 2020**												
2	Babcock Preserve PV Solar												
3	Solar		14,167				N/A	N/A	N/A	N/A	N/A	N/A	N/A
4	Plant Unit Info	74.5	14,167	26.4%	N/A	48.8%				N/A	N/A	N/A	
5	Babcock PV Solar												
6	Solar		12,899				N/A	N/A	N/A	N/A	N/A	N/A	N/A
7	Plant Unit Info	74.5	12,899	24.1%	N/A	44.4%				N/A	N/A	N/A	
8	Barefoot Bay PV Solar												
9	Solar		13,957				N/A	N/A	N/A	N/A	N/A	N/A	N/A
10	Plant Unit Info	74.5	13,957	26.0%	N/A	48.0%				N/A	N/A	N/A	
11	Blue Cypress PV Solar												
12	Solar		14,290				N/A	N/A	N/A	N/A	N/A	N/A	N/A
13	Plant Unit Info	74.5	14,290	26.6%	N/A	49.2%				N/A	N/A	N/A	
14	Blue Heron PV Solar												
15	Solar		14,167				N/A	N/A	N/A	N/A	N/A	N/A	N/A
16	Plant Unit Info	74.5	14,167	26.4%	N/A	48.8%				N/A	N/A	N/A	
17	Cattle Ranch PV Solar												
18	Solar		14,415				N/A	N/A	N/A	N/A	N/A	N/A	N/A
19	Plant Unit Info	74.5	14,415	26.9%	N/A	49.6%				N/A	N/A	N/A	
20	CCEC 3												
21	Light Oil		-				-	-	-	-	-	-	-
22	Gas		631,890				6,749	4,264,531	1,000,000	4,264,531	13,603,319	2.15	3.19
23	Plant Unit Info	1,308	631,890	67.1%	93.9%	67.1%	6,749			4,264,531	13,603,319	2.15	
24	Citrus PV Solar												
25	Solar		13,630				N/A	N/A	N/A	N/A	N/A	N/A	N/A
26	Plant Unit Info	74.5	13,630	25.4%	N/A	46.9%				N/A	N/A	N/A	
27	Coral Farms PV Solar												
28	Solar		14,602				N/A	N/A	N/A	N/A	N/A	N/A	N/A
29	Plant Unit Info	74.5	14,602	27.2%	N/A	50.3%				N/A	N/A	N/A	
30	Desoto Solar												
31	Solar		3,868				N/A	N/A	N/A	N/A	N/A	N/A	N/A
32	Plant Unit Info	25.0	3,868	21.5%	N/A	39.7%				N/A	N/A	N/A	
33	Echo River PV Solar												
34	Solar		16,335				N/A	N/A	N/A	N/A	N/A	N/A	N/A
35	Plant Unit Info	74.5	16,335	30.5%	N/A	56.2%				N/A	N/A	N/A	
36	Fort Myers GT												
37	Light Oil		-				-	-	-	-	-	-	-
38	Gas		-				-	-	-	-	-	-	-

ESTIMATED FOR THE PERIOD OF: JULY 2020 THROUGH DECEMBER 2020

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.	FCR - E-4 Schedule	Net Capability (MW)	Net Generation (MWH)	Capacity Factor (%)	Equivalent Availability Factor (%)	Net Output Factor (%)	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost ($)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel ($/Unit)
1	Plant Unit Info	0	-	N/A	N/A	N/A	-			-	-	-	
2	Fort Myers 2												
3	Gas		675,415				7,252	4,898,341	1,000,000	4,898,341	15,630,325	2.31	3.19
4	Plant Unit Info	1,730	675,415	54.2%	80.7%	54.2%	7,252			4,898,341	15,630,325	2.31	
5	Fort Myers 3A												
6	Light Oil		3,493				13,272	7,952	5,830,000	46,358	704,336	20.16	88.58
7	Gas		-				-	-	-	-	-	-	-
8	Plant Unit Info	164	3,493	3.0%	93.5%	76.1%	13,272			46,358	704,336	20.16	
9	Fort Myers 3B												
10	Light Oil		2,954				14,590	7,392	5,830,000	43,098	654,806	22.17	88.58
11	Gas		-				-	-	-	-	-	-	-
12	Plant Unit Info	168	2,954	2.4%	93.5%	62.8%	14,590			43,098	654,806	22.17	
13	Fort Myers 3C												
14	Light Oil		-				-	-	-	-	-	-	-
15	Gas		17,820				10,470	186,575	1,000,000	186,575	594,086	3.33	3.18
16	Plant Unit Info	219	17,820	11.3%	93.5%	92.5%	10,470			186,575	594,086	3.33	
17	Fort Myers 3D												
18	Light Oil		-				-	-	-	-	-	-	-
19	Gas		17,618				10,472	184,502	1,000,000	184,502	588,053	3.34	3.19
20	Plant Unit Info	219	17,618	11.2%	93.5%	92.5%	10,472			184,502	588,053	3.34	
21	Hammock PV Solar												
22	Solar		14,411				N/A	N/A	N/A	N/A	N/A	N/A	N/A
23	Plant Unit Info	74.5	14,411	26.9%	N/A	49.6%				N/A	N/A	N/A	
24	Hibiscus PV Solar												
25	Solar		13,975				N/A	N/A	N/A	N/A	N/A	N/A	N/A
26	Plant Unit Info	74.5	13,975	26.1%	N/A	48.1%				N/A	N/A	N/A	
27	Horizon PV Solar												
28	Solar		14,806				N/A	N/A	N/A	N/A	N/A	N/A	N/A
29	Plant Unit Info	74.5	14,806	27.6%	N/A	51.0%				N/A	N/A	N/A	
30	Indiantown FPL												
31	Coal		-					-	-	-	-	-	-
32	Plant Unit Info	0	-	N/A	N/A	N/A	-			-	-	-	
33	Indian River PV Solar												
34	Solar		14,277				N/A	N/A	N/A	N/A	N/A	N/A	N/A
35	Plant Unit Info	74.5	14,277	26.6%	N/A	49.1%				N/A	N/A	N/A	
36	Interstate PV Solar												
37	Solar		14,079				N/A	N/A	N/A	N/A	N/A	N/A	N/A
38	Plant Unit Info	74.5	14,079	26.3%	N/A	48.5%				N/A	N/A	N/A	

ESTIMATED FOR THE PERIOD OF: JULY 2020 THROUGH DECEMBER 2020

(1) Line No.	(2) FCR - E-4 Schedule	(3) Net Capability (MW)	(4) Net Generation (MWH)	(5) Capacity Factor (%)	(6) Equivalent Availability Factor (%)	(7) Net Output Factor (%)	(8) Avg Net Heat Rate (BTU/KWH)	(9) Fuel Burned (Units)	(10) Fuel Heat Value (BTU/unit)	(11) Fuel Burned (MMBTU)	(12) As Burned Fuel Cost ($)	(13) Fuel Cost per KWH (cents/KWH)	(14) Cost of Fuel ($/Unit)
1	Lauderdale GT												
2	Light Oil		-				-	-	-	-	-	-	-
3	Gas		-				-	-	-	-	-	-	-
4	Plant Unit Info	0	-		0.0%		-			-	-	-	
5	Lauderdale 6A												
6	Light Oil		-				-	-	-	-	-	-	-
7	Gas		22,823				10,483	239,244	1,000,000	239,244	763,169	3.34	3.19
8	Plant Unit Info	216	22,823	14.7%	93.5%	92.7%	10,483			239,244	763,169	3.34	
9	Lauderdale 6B												
10	Light Oil		-				-	-	-	-	-	-	-
11	Gas		22,022				10,477	230,718	1,000,000	230,718	736,546	3.34	3.19
12	Plant Unit Info	216	22,022	14.2%	93.5%	92.7%	10,477			230,718	736,546	3.34	
13	Lauderdale 6C												
14	Light Oil		3,579				12,991	7,975	5,830,000	46,493	508,375	14.20	63.75
15	Gas		-				-	-	-	-	-	-	-
16	Plant Unit Info	216	3,579	2.3%	93.5%	66.3%	12,991			46,493	508,375	14.20	
17	Lauderdale 6D												
18	Light Oil		5,344				13,468	12,345	5,830,000	71,974	786,996	14.73	63.75
19	Gas		-				-	-	-	-	-	-	-
20	Plant Unit Info	216	5,344	3.4%	93.5%	61.9%	13,468			71,974	786,996	14.73	
21	Lauderdale 6E												
22	Light Oil		3,760				13,145	8,478	5,830,000	49,427	540,457	14.37	63.75
23	Gas		-				-	-	-	-	-	-	-
24	Plant Unit Info	216	3,760	2.4%	93.5%	64.5%	13,145			49,427	540,457	14.37	
25	Loggerhead PV Solar												
26	Solar		14,449				N/A	N/A	N/A	N/A	N/A	N/A	N/A
27	Plant Unit Info	74.5	14,449	26.9%	N/A	49.7%				N/A	N/A	N/A	
28	Manatee 1												
29	Heavy Oil		15,273					25,639	6,400,000	164,089	1,721,426	11.27	67.14
30	Gas		88,317				10,744	948,850	1,000,000	948,850	2,951,440	3.34	3.11
31	Plant Unit Info	789	103,590	18.2%	96.2%	24.2%	10,744			1,112,939	4,672,867	4.51	
32	Manatee 2												
33	Heavy Oil		14,850					25,416	6,400,000	162,664	1,706,477	11.49	67.14
34	Gas		108,627				10,954	1,189,894	1,000,000	1,189,894	3,712,950	3.42	3.12
35	Plant Unit Info	789	123,477	21.7%	96.2%	21.7%	10,954			1,352,558	5,419,426	4.39	
36	Manatee 3												
37	Gas		471,913				7,219	3,406,657	1,000,000	3,406,657	10,602,746	2.25	3.11
38	Plant Unit Info	1,223	471,913	53.6%	94.1%	74.2%	7,219			3,406,657	10,602,746	2.25	

ESTIMATED FOR THE PERIOD OF: JULY 2020 THROUGH DECEMBER 2020

(1) Line No.	(2) FCR - E-4 Schedule	(3) Net Capability (MW)	(4) Net Generation (MWH)	(5) Capacity Factor (%)	(6) Equivalent Availability Factor (%)	(7) Net Output Factor (%)	(8) Avg Net Heat Rate (BTU/KWH)	(9) Fuel Burned (Units)	(10) Fuel Heat Value (BTU/unit)	(11) Fuel Burned (MMBTU)	(12) As Burned Fuel Cost ($)	(13) Fuel Cost per KWH (cents/KWH)	(14) Cost of Fuel ($/Unit)
1	Manatee PV Solar												
2	Solar		13,678				N/A	N/A	N/A	N/A	N/A	N/A	N/A
3	Plant Unit Info	74.5	13,678	25.5%	N/A	47.1%				N/A	N/A	N/A	
4	Martin 3												
5	Gas		193,402				7,487	1,447,920	1,000,000	1,447,920	4,522,864	2.34	3.12
6	Plant Unit Info	464	193,402	57.9%	93.9%	57.9%	7,487			1,447,920	4,522,864	2.34	
7	Martin 4												
8	Gas		203,442				7,491	1,524,017	1,000,000	1,524,017	4,756,887	2.34	3.12
9	Plant Unit Info	464	203,442	60.9%	94.0%	60.9%	7,491			1,524,017	4,756,887	2.34	
10	Martin 8 Solar												
11	Solar		10,320				N/A	N/A	N/A	N/A	N/A	N/A	N/A
12	Plant Unit Info	75.0	10,320	19.1%	N/A	35.3%				N/A	N/A	N/A	
13	Martin 8												
14	Light Oil		-				-	-	-	-	-	-	-
15	Gas		392,770				7,603	2,986,418	1,000,000	2,986,418	9,336,747	2.38	3.13
16	Plant Unit Info	1,218	392,770	44.8%	94.0%	86.0%	7,603			2,986,418	9,336,747	2.38	
17	Miami-Dade PV Solar												
18	Solar		13,518				N/A	N/A	N/A	N/A	N/A	N/A	N/A
19	Plant Unit Info	74.5	13,518	25.2%	N/A	46.5%				N/A	N/A	N/A	
20	Northern Preserve PV Solar												
21	Solar		12,314				N/A	N/A	N/A	N/A	N/A	N/A	N/A
22	Plant Unit Info	74.5	12,314	23.0%	N/A	42.4%				N/A	N/A	N/A	
23	Okechobee 1												
24	Light Oil		-				-	-	-	-	-	-	-
25	Gas		1,061,754				6,265	6,651,998	1,000,000	6,651,998	21,001,109	1.98	3.16
26	Plant Unit Info	1,618	1,061,754	91.1%	96.7%	91.1%	6,265			6,651,998	21,001,109	1.98	
27	Okeechobee PV Solar												
28	Solar		14,608				N/A	N/A	N/A	N/A	N/A	N/A	N/A
29	Plant Unit Info	74.5	14,608	27.2%	N/A	50.3%				N/A	N/A	N/A	
30	PEEC												
31	Light Oil		-				-	-	-	-	-	-	-
32	Gas		660,514				6,390	4,220,526	1,000,000	4,220,526	13,471,001	2.04	3.19
33	Plant Unit Info	1,254	660,514	73.2%	76.1%	73.2%	6,390			4,220,526	13,471,001	2.04	
34	Pioneer Trail PV Solar												
35	Solar		13,694				N/A	N/A	N/A	N/A	N/A	N/A	N/A
36	Plant Unit Info	74.5	13,694	25.5%	N/A	47.1%				N/A	N/A	N/A	
37	Riviera 5												
38	Light Oil		-				-	-	-	-	-	-	-

ESTIMATED FOR THE PERIOD OF: JULY 2020 THROUGH DECEMBER 2020

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.	FCR - E-4 Schedule	Net Capability (MW)	Net Generation (MWH)	Capacity Factor (%)	Equivalent Availability Factor (%)	Net Output Factor (%)	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost ($)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel ($/Unit)
1	Gas		798,906				6,639	5,303,749	1,000,000	5,303,749	16,744,535	2.10	3.16
2	Plant Unit Info	1,308	798,906	84.8%	93.9%	84.8%	6,639			5,303,749	16,744,535	2.10	
3	Sanford 4												
4	Gas		410,604				7,255	2,978,939	1,000,000	2,978,939	9,501,940	2.31	3.19
5	Plant Unit Info	1,147	410,604	49.7%	94.0%	49.7%	7,255			2,978,939	9,501,940	2.31	
6	Sanford 5												
7	Gas		438,574				7,105	3,116,029	1,000,000	3,116,029	9,939,905	2.27	3.19
8	Plant Unit Info	1,147	438,574	53.1%	94.0%	53.1%	7,105			3,116,029	9,939,905	2.27	
9	Scherer 4												
10	Coal		189,556					126,530	17,000,000	2,151,007	5,595,270	2.95	44.22
11	Plant Unit Info	636	189,556	41.4%	94.8%	41.4%	11,348			2,151,007	5,595,270	2.95	
12	Southfork PV Solar												
13	Solar		16,374				N/A	N/A	N/A	N/A	N/A	N/A	N/A
14	Plant Unit Info	74.5	16,374	30.5%	N/A	56.4%				N/A	N/A	N/A	
15	Space Coast												
16	Solar		1,421				N/A	N/A	N/A	N/A	N/A	N/A	N/A
17	Plant Unit Info	10.0	1,421	19.7%	N/A	36.4%				N/A	N/A	N/A	
18	St Lucie 1												
19	Nuclear		688,631					7,271,879	1,000,000	7,271,879	3,508,681	0.51	0.48
20	Plant Unit Info	981	688,631	97.5%	97.5%	97.5%	10,560			7,271,879	3,508,681	0.51	
21	St Lucie 2												
22	Nuclear		589,637					6,188,655	1,000,000	6,188,655	2,685,876	0.46	0.43
23	Plant Unit Info	840	589,637	97.5%	97.5%	97.5%	10,496			6,188,655	2,685,876	0.46	
24	Sunshine Gateway PV Solar												
25	Solar		14,199				N/A	N/A	N/A	N/A	N/A	N/A	N/A
26	Plant Unit Info	74.5	14,199	26.5%	N/A	48.9%				N/A	N/A	N/A	
27	Sweet Bay PV Solar												
28	Solar		12,663				N/A	N/A	N/A	N/A	N/A	N/A	N/A
29	Plant Unit Info	74.5	12,663	23.6%	N/A	N/A				N/A	N/A	N/A	
30	Turkey Point 3												
31	Nuclear		587,592					6,356,806	1,000,000	6,356,806	3,060,001	0.52	0.48
32	Plant Unit Info	837	587,592	97.5%	97.5%	97.5%	10,818			6,356,806	3,060,001	0.52	
33	Turkey Point 4												
34	Nuclear		573,203					6,321,966	1,000,000	6,321,966	3,159,719	0.55	0.50
35	Plant Unit Info	821	573,203	97.0%	95.7%	97.0%	11,029			6,321,966	3,159,719	0.55	
36	Turkey Point 5												
37	Light Oil		-				-	-	-	-	-	-	-
38	Gas		456,521				7,176	3,276,015	1,000,000	3,276,015	10,447,851	2.29	3.19

ESTIMATED FOR THE PERIOD OF: JULY 2020 THROUGH DECEMBER 2020

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.	FCR - E-4 Schedule	Net Capability (MW)	Net Generation (MWH)	Capacity Factor (%)	Equivalent Availability Factor (%)	Net Output Factor (%)	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost ($)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel ($/Unit)
1	Plant Unit Info	1,256	456,521	50.5%	94.0%	50.5%	7,176			3,276,015	10,447,851	2.29	
2	Twin Lakes PV Solar												
3	Solar		14,028				N/A	N/A	N/A	N/A	N/A	N/A	N/A
4	Plant Unit Info	74.5	14,028	26.2%	N/A	48.3%				N/A	N/A	N/A	
5	WCEC 01												
6	Light Oil		-				-	-	-	-	-	-	-
7	Gas		773,905				6,633	5,133,560	1,000,000	5,133,560	15,965,832	2.06	3.11
8	Plant Unit Info	1,223	773,905	87.9%	93.9%	87.9%	6,633			5,133,560	15,965,832	2.06	
9	WCEC 02												
10	Light Oil		-				-	-	-	-	-	-	-
11	Gas		778,876				6,661	5,188,059	1,000,000	5,188,059	16,135,425	2.07	3.11
12	Plant Unit Info	1,223	778,876	88.5%	93.9%	88.5%	6,661			5,188,059	16,135,425	2.07	
13	WCEC 03												
14	Light Oil		-				-	-	-	-	-	-	-
15	Gas		111,915				6,883	770,327	1,000,000	770,327	2,400,588	2.15	3.12
16	Plant Unit Info	1,211	111,915	7.2%	7.2%	48.1%	6,883			770,327	2,400,588	2.15	
17	Wildflower PV Solar												
18	Solar		14,791				N/A	N/A	N/A	N/A	N/A	N/A	N/A
19	Plant Unit Info	74.5	14,791	27.6%	N/A	50.9%				N/A	N/A	N/A	
20	System Totals												
21	Plant Unit Info	27,310	11,385,436				7,643			87,021,285	208,039,737	1.83	
22													
23													
24													
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ESTIMATED FOR THE PERIOD OF: JULY 2020 THROUGH DECEMBER 2020

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.	FCR - E-4 Schedule	Net Capability (MW)	Net Generation (MWH)	Capacity Factor (%)	Equivalent Availability Factor (%)	Net Output Factor (%)	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost ($)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel ($/Unit)
1	**Oct - 2020**												
2	Babcock Preserve PV Solar												
3	Solar		14,948				N/A	N/A	N/A	N/A	N/A	N/A	N/A
4	Plant Unit Info	74.5	14,948	27.0%	N/A	53.9%				N/A	N/A	N/A	
5	Babcock PV Solar												
6	Solar		13,941				N/A	N/A	N/A	N/A	N/A	N/A	N/A
7	Plant Unit Info	74.5	13,941	25.2%	N/A	46.4%				N/A	N/A	N/A	
8	Barefoot Bay PV Solar												
9	Solar		14,309				N/A	N/A	N/A	N/A	N/A	N/A	N/A
10	Plant Unit Info	74.5	14,309	25.8%	N/A	51.6%				N/A	N/A	N/A	
11	Blue Cypress PV Solar												
12	Solar		14,540				N/A	N/A	N/A	N/A	N/A	N/A	N/A
13	Plant Unit Info	74.5	14,540	26.2%	N/A	52.5%				N/A	N/A	N/A	
14	Blue Heron PV Solar												
15	Solar		14,948				N/A	N/A	N/A	N/A	N/A	N/A	N/A
16	Plant Unit Info	74.5	14,948	27.0%	N/A	53.9%				N/A	N/A	N/A	
17	Cattle Ranch PV Solar												
18	Solar		14,269				N/A	N/A	N/A	N/A	N/A	N/A	N/A
19	Plant Unit Info	74.5	14,269	25.7%	N/A	51.5%				N/A	N/A	N/A	
20	CCEC 3												
21	Light Oil		-				-	-	-	-	-	-	-
22	Gas		334,269				6,691	2,236,612	1,000,000	2,236,612	7,548,778	2.26	3.38
23	Plant Unit Info	1,308	334,269	34.4%	39.1%	76.1%	6,691			2,236,612	7,548,778	2.26	
24	Citrus PV Solar												
25	Solar		14,046				N/A	N/A	N/A	N/A	N/A	N/A	N/A
26	Plant Unit Info	74.5	14,046	25.3%	N/A	46.8%				N/A	N/A	N/A	
27	Coral Farms PV Solar												
28	Solar		15,020				N/A	N/A	N/A	N/A	N/A	N/A	N/A
29	Plant Unit Info	74.5	15,020	27.1%	N/A	54.2%				N/A	N/A	N/A	
30	Desoto Solar												
31	Solar		3,833				N/A	N/A	N/A	N/A	N/A	N/A	N/A
32	Plant Unit Info	25.0	3,833	20.6%	N/A	41.2%				N/A	N/A	N/A	
33	Echo River PV Solar												
34	Solar		16,339				N/A	N/A	N/A	N/A	N/A	N/A	N/A
35	Plant Unit Info	74.5	16,339	29.5%	N/A	59.0%				N/A	N/A	N/A	
36	Fort Myers GT												
37	Light Oil		-				-	-	-	-	-	-	-
38	Gas		-				-	-	-	-	-	-	-

ESTIMATED FOR THE PERIOD OF: JULY 2020 THROUGH DECEMBER 2020

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.	FCR - E-4 Schedule	Net Capability (MW)	Net Generation (MWH)	Capacity Factor (%)	Equivalent Availability Factor (%)	Net Output Factor (%)	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost ($)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel ($/Unit)
1	Plant Unit Info	0		N/A	N/A	N/A	-			-	-	-	
2	Fort Myers 2												
3	Gas		794,963				7,211	5,732,139	1,000,000	5,732,139	19,335,586	2.43	3.37
4	Plant Unit Info	1,730	794,963	61.8%	94.0%	61.8%	7,211			5,732,139	19,335,586	2.43	
5	Fort Myers 3A												
6	Light Oil		3,947				13,079	8,854	5,830,000	51,621	784,299	19.87	88.58
7	Gas		-				-	-	-	-	-	-	-
8	Plant Unit Info	164	3,947	3.2%	93.5%	77.6%	13,079			51,621	784,299	19.87	
9	Fort Myers 3B												
10	Light Oil		3,901				13,170	8,813	5,830,000	51,378	780,607	20.01	88.58
11	Gas		-				-	-	-	-	-	-	-
12	Plant Unit Info	168	3,901	3.1%	93.5%	74.9%	13,170			51,378	780,607	20.01	
13	Fort Myers 3C												
14	Light Oil		-				-	-	-	-	-	-	-
15	Gas		19,328				10,491	202,776	1,000,000	202,776	687,038	3.55	3.39
16	Plant Unit Info	219	19,328	11.9%	93.5%	91.9%	10,491			202,776	687,038	3.55	
17	Fort Myers 3D												
18	Light Oil		-				-	-	-	-	-	-	-
19	Gas		22,163				10,486	232,391	1,000,000	232,391	787,336	3.55	3.39
20	Plant Unit Info	219	22,163	13.6%	93.5%	92.0%	10,486			232,391	787,336	3.55	
21	Hammock PV Solar												
22	Solar		15,340				N/A	N/A	N/A	N/A	N/A	N/A	N/A
23	Plant Unit Info	74.5	15,340	27.7%	N/A	55.4%				N/A	N/A	N/A	
24	Hibiscus PV Solar												
25	Solar		13,972				N/A	N/A	N/A	N/A	N/A	N/A	N/A
26	Plant Unit Info	74.5	13,972	25.2%	N/A	50.4%				N/A	N/A	N/A	
27	Horizon PV Solar												
28	Solar		15,171				N/A	N/A	N/A	N/A	N/A	N/A	N/A
29	Plant Unit Info	74.5	15,171	27.4%	N/A	54.7%				N/A	N/A	N/A	
30	Indiantown FPL												
31	Coal		-					-	-	-	-	-	-
32	Plant Unit Info	0		N/A	N/A	N/A	-			-	-	-	
33	Indian River PV Solar												
34	Solar		14,532				N/A	N/A	N/A	N/A	N/A	N/A	N/A
35	Plant Unit Info	74.5	14,532	26.2%	N/A	52.4%				N/A	N/A	N/A	
36	Interstate PV Solar												
37	Solar		14,238				N/A	N/A	N/A	N/A	N/A	N/A	N/A
38	Plant Unit Info	74.5	14,238	25.7%	N/A	51.4%				N/A	N/A	N/A	

ESTIMATED FOR THE PERIOD OF: JULY 2020 THROUGH DECEMBER 2020

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.	FCR - E-4 Schedule	Net Capability (MW)	Net Generation (MWH)	Capacity Factor (%)	Equivalent Availability Factor (%)	Net Output Factor (%)	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost ($)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel ($/Unit)
1	Lauderdale GT												
2	Light Oil		-				-	-	-	-	-	-	-
3	Gas		-				-	-	-	-	-	-	-
4	Plant Unit Info	0		N/A	N/A	N/A	-			-	-	-	
5	Lauderdale 6A												
6	Light Oil		-				-	-	-	-	-	-	-
7	Gas		24,424				10,481	255,997	1,000,000	255,997	866,368	3.55	3.38
8	Plant Unit Info	216	24,424	15.2%	93.5%	92.7%	10,481			255,997	866,368	3.55	
9	Lauderdale 6B												
10	Light Oil		-				-	-	-	-	-	-	-
11	Gas		25,425				10,473	266,279	1,000,000	266,279	901,196	3.54	3.38
12	Plant Unit Info	216	25,425	15.8%	93.5%	92.7%	10,473			266,279	901,196	3.54	
13	Lauderdale 6C												
14	Light Oil		5,157				12,336	10,912	5,830,000	63,618	671,806	13.03	61.56
15	Gas		-				-	-	-	-	-	-	-
16	Plant Unit Info	216	5,157	3.2%	93.5%	72.3%	12,336			63,618	671,806	13.03	
17	Lauderdale 6D												
18	Light Oil		5,525				12,639	11,978	5,830,000	69,832	737,426	13.35	61.56
19	Gas		-				-	-	-	-	-	-	-
20	Plant Unit Info	216	5,525	3.4%	93.5%	69.1%	12,639			69,832	737,426	13.35	
21	Lauderdale 6E												
22	Light Oil		5,655				12,335	11,964	5,830,000	69,752	736,581	13.03	61.56
23	Gas		-				-	-	-	-	-	-	-
24	Plant Unit Info	216	5,655	3.5%	93.5%	72.7%	12,335			69,752	736,581	13.03	
25	Loggerhead PV Solar												
26	Solar		14,876				N/A	N/A	N/A	N/A	N/A	N/A	N/A
27	Plant Unit Info	74.5	14,876	26.8%	N/A	53.7%				N/A	N/A	N/A	
28	Manatee 1												
29	Heavy Oil		16,311					27,801	6,400,000	177,924	1,866,567	11.44	67.14
30	Gas		85,798				10,908	935,904	1,000,000	935,904	3,089,484	3.60	3.30
31	Plant Unit Info	789	102,109	17.4%	96.2%	27.1%	10,908			1,113,828	4,956,051	4.85	
32	Manatee 2												
33	Heavy Oil		16,223					27,287	6,400,000	174,634	1,832,052	11.29	67.14
34	Gas		80,183				10,764	863,120	1,000,000	863,120	2,845,547	3.55	3.30
35	Plant Unit Info	789	96,406	16.4%	96.2%	25.4%	10,764			1,037,754	4,677,599	4.85	
36	Manatee 3												
37	Gas		586,969				6,970	4,091,229	1,000,000	4,091,229	13,487,976	2.30	3.30
38	Plant Unit Info	1,223	586,969	64.5%	94.1%	65.4%	6,970			4,091,229	13,487,976	2.30	

ESTIMATED FOR THE PERIOD OF: JULY 2020 THROUGH DECEMBER 2020

(1) Line No.	(2) FCR - E-4 Schedule	(3) Net Capability (MW)	(4) Net Generation (MWH)	(5) Capacity Factor (%)	(6) Equivalent Availability Factor (%)	(7) Net Output Factor (%)	(8) Avg Net Heat Rate (BTU/KWH)	(9) Fuel Burned (Units)	(10) Fuel Heat Value (BTU/unit)	(11) Fuel Burned (MMBTU)	(12) As Burned Fuel Cost ($)	(13) Fuel Cost per KWH (cents/KWH)	(14) Cost of Fuel ($/Unit)
1	Manatee PV Solar												
2	Solar		14,472				N/A	N/A	N/A	N/A	N/A	N/A	N/A
3	Plant Unit Info	74.5	14,472	26.1%	N/A	48.2%				N/A	N/A	N/A	
4	Martin 3												
5	Gas		138,108				7,818	1,079,661	1,000,000	1,079,661	3,573,904	2.59	3.31
6	Plant Unit Info	464	138,108	40.0%	93.9%	76.9%	7,818			1,079,661	3,573,904	2.59	
7	Martin 4												
8	Gas		211,018				7,474	1,577,083	1,000,000	1,577,083	5,207,763	2.47	3.30
9	Plant Unit Info	464	211,018	61.1%	94.0%	61.1%	7,474			1,577,083	5,207,763	2.47	
10	Martin 8 Solar												
11	Solar		9,114				N/A	N/A	N/A	N/A	N/A	N/A	N/A
12	Plant Unit Info	75.0	9,114	16.3%	N/A	30.2%				N/A	N/A	N/A	
13	Martin 8												
14	Light Oil		-				-	-	-	-	-	-	-
15	Gas		551,630				7,146	3,941,784	1,000,000	3,941,784	13,010,166	2.36	3.30
16	Plant Unit Info	1,218	551,630	60.9%	94.0%	67.5%	7,146			3,941,784	13,010,166	2.36	
17	Miami-Dade PV Solar												
18	Solar		13,970				N/A	N/A	N/A	N/A	N/A	N/A	N/A
19	Plant Unit Info	74.5	13,970	25.2%	N/A	50.4%				N/A	N/A	N/A	
20	Northern Preserve PV Solar												
21	Solar		12,992				N/A	N/A	N/A	N/A	N/A	N/A	N/A
22	Plant Unit Info	74.5	12,992	23.4%	N/A	46.9%				N/A	N/A	N/A	
23	Okechobee 1												
24	Light Oil		-				-	-	-	-	-	-	-
25	Gas		1,100,585				6,263	6,893,181	1,000,000	6,893,181	23,190,152	2.11	3.36
26	Plant Unit Info	1,618	1,100,585	91.4%	96.7%	91.4%	6,263			6,893,181	23,190,152	2.11	
27	Okeechobee PV Solar												
28	Solar		14,662				N/A	N/A	N/A	N/A	N/A	N/A	N/A
29	Plant Unit Info	74.5	14,662	26.5%	N/A	52.9%				N/A	N/A	N/A	
30	PEEC												
31	Light Oil		-				-	-	-	-	-	-	-
32	Gas		568,883				6,420	3,652,277	1,000,000	3,652,277	12,313,387	2.16	3.37
33	Plant Unit Info	1,254	568,883	61.0%	61.6%	61.0%	6,420			3,652,277	12,313,387	2.16	
34	Pioneer Trail PV Solar												
35	Solar		13,603				N/A	N/A	N/A	N/A	N/A	N/A	N/A
36	Plant Unit Info	74.5	13,603	24.5%	N/A	49.1%				N/A	N/A	N/A	
37	Riviera 5												
38	Light Oil		-				-	-	-	-	-	-	-

ESTIMATED FOR THE PERIOD OF: JULY 2020 THROUGH DECEMBER 2020

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.	FCR - E-4 Schedule	Net Capability (MW)	Net Generation (MWH)	Capacity Factor (%)	Equivalent Availability Factor (%)	Net Output Factor (%)	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost ($)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel ($/Unit)
1	Gas		872,634				6,610	5,767,728	1,000,000	5,767,728	19,384,734	2.22	3.36
2	Plant Unit Info	1,308	872,634	89.7%	93.9%	89.7%	6,610			5,767,728	19,384,734	2.22	
3	Sanford 4												
4	Gas		382,392				7,269	2,779,779	1,000,000	2,779,779	9,391,619	2.46	3.38
5	Plant Unit Info	1,147	382,392	44.8%	94.0%	54.8%	7,269			2,779,779	9,391,619	2.46	
6	Sanford 5												
7	Gas		478,848				7,069	3,384,748	1,000,000	3,384,748	11,415,876	2.38	3.37
8	Plant Unit Info	1,147	478,848	56.1%	94.0%	56.1%	7,069			3,384,748	11,415,876	2.38	
9	Scherer 4												
10	Coal		203,664					135,255	17,000,000	2,299,336	5,940,492	2.92	43.92
11	Plant Unit Info	636	203,664	43.0%	94.8%	43.0%	11,290			2,299,336	5,940,492	2.92	
12	Southfork PV Solar												
13	Solar		16,729				N/A	N/A	N/A	N/A	N/A	N/A	N/A
14	Plant Unit Info	74.5	16,729	30.2%	N/A	60.4%				N/A	N/A	N/A	
15	Space Coast												
16	Solar		1,451				N/A	N/A	N/A	N/A	N/A	N/A	N/A
17	Plant Unit Info	10.0	1,451	19.5%	N/A	39.0%				N/A	N/A	N/A	
18	St Lucie 1												
19	Nuclear		711,586					7,514,275	1,000,000	7,514,275	3,625,638	0.51	0.48
20	Plant Unit Info	981	711,586	97.5%	97.5%	97.5%	10,560			7,514,275	3,625,638	0.51	
21	St Lucie 2												
22	Nuclear		609,292					6,394,944	1,000,000	6,394,944	2,775,405	0.46	0.43
23	Plant Unit Info	840	609,292	97.5%	97.5%	97.5%	10,496			6,394,944	2,775,405	0.46	
24	Sunshine Gateway PV Solar												
25	Solar		14,347				N/A	N/A	N/A	N/A	N/A	N/A	N/A
26	Plant Unit Info	74.5	14,347	25.9%	N/A	56.5%				N/A	N/A	N/A	
27	Sweet Bay PV Solar												
28	Solar		13,027				N/A	N/A	N/A	N/A	N/A	N/A	N/A
29	Plant Unit Info	74.5	13,027	23.5%	N/A					N/A	N/A	N/A	
30	Turkey Point 3												
31	Nuclear		607,178					6,568,699	1,000,000	6,568,699	3,162,001	0.52	0.48
32	Plant Unit Info	837	607,178	97.5%	97.5%	97.5%	10,818			6,568,699	3,162,001	0.52	
33	Turkey Point 4												
34	Nuclear		35,664					393,348	1,000,000	393,348	196,595	0.55	0.50
35	Plant Unit Info	821	35,664	5.8%	5.7%	90.5%	11,029			393,348	196,595	0.55	
36	Turkey Point 5												
37	Light Oil		-					-	-	-	-	-	-
38	Gas		331,824				7,479	2,481,803	1,000,000	2,481,803	8,392,881	2.53	3.38

ESTIMATED FOR THE PERIOD OF: JULY 2020 THROUGH DECEMBER 2020

(1) Line No.	(2) FCR - E-4 Schedule	(3) Net Capability (MW)	(4) Net Generation (MWH)	(5) Capacity Factor (%)	(6) Equivalent Availability Factor (%)	(7) Net Output Factor (%)	(8) Avg Net Heat Rate (BTU/KWH)	(9) Fuel Burned (Units)	(10) Fuel Heat Value (BTU/unit)	(11) Fuel Burned (MMBTU)	(12) As Burned Fuel Cost ($)	(13) Fuel Cost per KWH (cents/KWH)	(14) Cost of Fuel ($/Unit)
1	Plant Unit Info	1,256	331,824	35.5%	94.0%	72.0%	7,479			2,481,803	8,392,881	2.53	
2	Twin Lakes PV Solar												
3	Solar		13,886				N/A	N/A	N/A	N/A	N/A	N/A	N/A
4	Plant Unit Info	74.5	13,886	25.1%	N/A	50.1%				N/A	N/A	N/A	
5	WCEC 01												
6	Light Oil		-					-	-	-	-	-	-
7	Plant Unit Info	0		N/A	N/A	N/A	-			-	-	-	
8	WCEC 02												
9	Light Oil		-				-	-	-	-	-	-	-
10	Gas		819,829				6,651	5,452,832	1,000,000	5,452,832	17,952,361	2.19	3.29
11	Plant Unit Info	1,223	819,829	90.1%	93.9%	90.1%	6,651			5,452,832	17,952,361	2.19	
12	WCEC 03												
13	Light Oil		-				-	-	-	-	-	-	-
14	Gas		684,469				6,688	4,577,538	1,000,000	4,577,538	15,077,023	2.20	3.29
15	Plant Unit Info	1,228	684,469	74.9%	77.8%	74.9%	6,688			4,577,538	15,077,023	2.20	
16	Wildflower PV Solar												
17	Solar		15,474				N/A	N/A	N/A	N/A	N/A	N/A	N/A
18	Plant Unit Info	74.5	15,474	27.9%	N/A	55.8%				N/A	N/A	N/A	
19	System Totals												
20	Plant Unit Info	26,104	10,715,894				7,487			80,234,222	211,568,645	1.97	
21													
22													
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ESTIMATED FOR THE PERIOD OF: JULY 2020 THROUGH DECEMBER 2020

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.	FCR - E-4 Schedule	Net Capability (MW)	Net Generation (MWH)	Capacity Factor (%)	Equivalent Availability Factor (%)	Net Output Factor (%)	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost ($)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel ($/Unit)
1	**Nov - 2020**												
2	Babcock Preserve PV Solar												
3	Solar		13,755				N/A	N/A	N/A	N/A	N/A	N/A	N/A
4	Plant Unit Info	74.5	13,755	25.6%	N/A	55.9%				N/A	N/A	N/A	
5	Babcock PV Solar												
6	Solar		12,647				N/A	N/A	N/A	N/A	N/A	N/A	N/A
7	Plant Unit Info	74.5	12,647	23.6%	N/A	47.2%				N/A	N/A	N/A	
8	Barefoot Bay PV Solar												
9	Solar		12,750				N/A	N/A	N/A	N/A	N/A	N/A	N/A
10	Plant Unit Info	74.5	12,750	23.8%	N/A	51.9%				N/A	N/A	N/A	
11	Blue Cypress PV Solar												
12	Solar		13,101				N/A	N/A	N/A	N/A	N/A	N/A	N/A
13	Plant Unit Info	74.5	13,101	24.4%	N/A	53.3%				N/A	N/A	N/A	
14	Blue Heron PV Solar												
15	Solar		13,755				N/A	N/A	N/A	N/A	N/A	N/A	N/A
16	Plant Unit Info	74.5	13,755	25.6%	N/A	55.9%				N/A	N/A	N/A	
17	Cattle Ranch PV Solar												
18	Solar		12,159				N/A	N/A	N/A	N/A	N/A	N/A	N/A
19	Plant Unit Info	74.5	12,159	22.7%	N/A	49.5%				N/A	N/A	N/A	
20	CCEC 3												
21	Light Oil		-				-	-	-	-	-	-	-
22	Gas		365,760				6,760	2,472,646	1,000,000	2,472,646	10,319,928	2.82	4.17
23	Plant Unit Info	1,326	365,760	38.3%	57.2%	60.5%	6,760			2,472,646	10,319,928	2.82	
24	Citrus PV Solar												
25	Solar		12,570				N/A	N/A	N/A	N/A	N/A	N/A	N/A
26	Plant Unit Info	74.5	12,570	23.4%	N/A	46.9%				N/A	N/A	N/A	
27	Coral Farms PV Solar												
28	Solar		13,212				N/A	N/A	N/A	N/A	N/A	N/A	N/A
29	Plant Unit Info	74.5	13,212	24.6%	N/A	53.7%				N/A	N/A	N/A	
30	Desoto Solar												
31	Solar		3,261				N/A	N/A	N/A	N/A	N/A	N/A	N/A
32	Plant Unit Info	25.0	3,261	18.1%	N/A	39.5%				N/A	N/A	N/A	
33	Echo River PV Solar												
34	Solar		13,329				N/A	N/A	N/A	N/A	N/A	N/A	N/A
35	Plant Unit Info	74.5	13,329	24.9%	N/A	54.2%				N/A	N/A	N/A	
36	Fort Myers GT												
37	Light Oil		-				-	-	-	-	-	-	-
38	Gas		-				-	-	-	-	-	-	-

ESTIMATED FOR THE PERIOD OF: JULY 2020 THROUGH DECEMBER 2020

(1) Line No.	(2) FCR - E-4 Schedule	(3) Net Capability (MW)	(4) Net Generation (MWH)	(5) Capacity Factor (%)	(6) Equivalent Availability Factor (%)	(7) Net Output Factor (%)	(8) Avg Net Heat Rate (BTU/KWH)	(9) Fuel Burned (Units)	(10) Fuel Heat Value (BTU/unit)	(11) Fuel Burned (MMBTU)	(12) As Burned Fuel Cost ($)	(13) Fuel Cost per KWH (cents/KWH)	(14) Cost of Fuel ($/Unit)
1	Plant Unit Info	0		N/A	N/A	N/A	-			-	-	-	
2	Fort Myers 2												
3	Gas		690,232				7,266	5,015,030	1,000,000	5,015,030	20,886,858	3.03	4.16
4	Plant Unit Info	1,770	690,232	54.2%	93.4%	54.2%	7,266			5,015,030	20,886,858	3.03	
5	Fort Myers 3A												
6	Light Oil		-				-	-	-	-	-	-	-
7	Gas		-				-	-	-	-	-	-	-
8	Plant Unit Info	0		N/A	N/A	N/A	-			-	-	-	
9	Fort Myers 3B												
10	Light Oil		-				-	-	-	-	-	-	-
11	Gas		-				-	-	-	-	-	-	-
12	Plant Unit Info	0		N/A	N/A	N/A	-			-	-	-	
13	Fort Myers 3C												
14	Light Oil		32				10,559	58	5,830,000	337	5,120	16.04	88.58
15	Gas		4,056				10,559	42,830	1,000,000	42,830	178,344	4.40	4.16
16	Plant Unit Info	221	4,088	2.6%	93.5%	92.5%	10,559			43,167	183,464	4.49	
17	Fort Myers 3D												
18	Light Oil		-				-	-	-	-	-	-	-
19	Gas		4,088				10,556	43,151	1,000,000	43,151	179,675	4.40	4.16
20	Plant Unit Info	221	4,088	2.6%	93.5%	92.5%	10,556			43,151	179,675	4.40	
21	Hammock PV Solar												
22	Solar		14,053				N/A	N/A	N/A	N/A	N/A	N/A	N/A
23	Plant Unit Info	74.5	14,053	26.2%	N/A	57.2%				N/A	N/A	N/A	
24	Hibiscus PV Solar												
25	Solar		12,211				N/A	N/A	N/A	N/A	N/A	N/A	N/A
26	Plant Unit Info	74.5	12,211	22.8%	N/A	49.7%				N/A	N/A	N/A	
27	Horizon PV Solar												
28	Solar		13,335				N/A	N/A	N/A	N/A	N/A	N/A	N/A
29	Plant Unit Info	74.5	13,335	24.9%	N/A	54.2%				N/A	N/A	N/A	
30	Indiantown FPL												
31	Coal		-					-	-	-	-	-	-
32	Plant Unit Info	0		N/A	N/A	N/A	-			-	-	-	
33	Indian River PV Solar												
34	Solar		13,089				N/A	N/A	N/A	N/A	N/A	N/A	N/A
35	Plant Unit Info	74.5	13,089	24.4%	N/A	53.2%				N/A	N/A	N/A	
36	Interstate PV Solar												
37	Solar		12,422				N/A	N/A	N/A	N/A	N/A	N/A	N/A
38	Plant Unit Info	74.5	12,422	23.2%	N/A	50.5%				N/A	N/A	N/A	

ESTIMATED FOR THE PERIOD OF: JULY 2020 THROUGH DECEMBER 2020

(1) Line No.	(2) FCR - E-4 Schedule	(3) Net Capability (MW)	(4) Net Generation (MWH)	(5) Capacity Factor (%)	(6) Equivalent Availability Factor (%)	(7) Net Output Factor (%)	(8) Avg Net Heat Rate (BTU/KWH)	(9) Fuel Burned (Units)	(10) Fuel Heat Value (BTU/unit)	(11) Fuel Burned (MMBTU)	(12) As Burned Fuel Cost ($)	(13) Fuel Cost per KWH (cents/KWH)	(14) Cost of Fuel ($/Unit)
1	Lauderdale GT												
2	Light Oil		-				-	-	-	-	-	-	-
3	Gas		-				-	-	-	-	-	-	-
4	Plant Unit Info	0	-	N/A	N/A	N/A	-			-	-	-	
5	Lauderdale 6A												
6	Light Oil		-				-	-	-	-	-	-	-
7	Gas		4,444				10,572	46,984	1,000,000	46,984	195,573	4.40	4.16
8	Plant Unit Info	218	4,444	2.8%	93.5%	92.7%	10,572			46,984	195,573	4.40	
9	Lauderdale 6B												
10	Light Oil		-				-	-	-	-	-	-	-
11	Gas		4,040				10,600	42,822	1,000,000	42,822	178,305	4.41	4.16
12	Plant Unit Info	218	4,040	2.6%	93.5%	92.7%	10,600			42,822	178,305	4.41	
13	Lauderdale 6C												
14	Gas		-				-	-	-	-	-	-	-
15	Plant Unit Info	0	-	N/A	N/A	N/A	-			-	-	-	
16	Lauderdale 6D												
17	Light Oil		-				-	-	-	-	-	-	-
18	Gas		-				-	-	-	-	-	-	-
19	Plant Unit Info	0	-	N/A	N/A	N/A	-			-	-	-	
20	Lauderdale 6E												
21	Light Oil		-				-	-	-	-	-	-	-
22	Gas		-				-	-	-	-	-	-	-
23	Plant Unit Info	0	-	N/A	N/A	N/A	-			-	-	-	
24	Loggerhead PV Solar												
25	Solar		13,286				N/A	N/A	N/A	N/A	N/A	N/A	N/A
26	Plant Unit Info	74.5	13,286	24.8%	N/A	54.0%				N/A	N/A	N/A	
27	Manatee 1												
28	Heavy Oil		1,868					3,296	6,400,000	21,097	221,325	11.85	67.14
29	Gas		16,475				11,292	186,037	1,000,000	186,037	767,016	4.66	4.12
30	Plant Unit Info	796	18,343	3.2%	96.2%	25.0%	11,292			207,134	988,341	5.39	
31	Manatee 2												
32	Heavy Oil		1,416					2,659	6,400,000	17,015	178,501	12.61	67.14
33	Gas		14,430				12,016	173,389	1,000,000	173,389	715,404	4.96	4.13
34	Plant Unit Info	797	15,846	2.8%	96.2%	25.2%	12,016			190,404	893,905	5.64	
35	Manatee 3												
36	Gas		198,960				7,192	1,430,978	1,000,000	1,430,978	5,896,634	2.96	4.12
37	Plant Unit Info	1,254	198,960	22.0%	59.1%	61.3%	7,192			1,430,978	5,896,634	2.96	
38	Manatee PV Solar												

ESTIMATED FOR THE PERIOD OF: JULY 2020 THROUGH DECEMBER 2020

(1) Line No.	(2) FCR - E-4 Schedule	(3) Net Capability (MW)	(4) Net Generation (MWH)	(5) Capacity Factor (%)	(6) Equivalent Availability Factor (%)	(7) Net Output Factor (%)	(8) Avg Net Heat Rate (BTU/KWH)	(9) Fuel Burned (Units)	(10) Fuel Heat Value (BTU/unit)	(11) Fuel Burned (MMBTU)	(12) As Burned Fuel Cost ($)	(13) Fuel Cost per KWH (cents/KWH)	(14) Cost of Fuel ($/Unit)
1	Solar		12,714				N/A	N/A	N/A	N/A	N/A	N/A	N/A
2	Plant Unit Info	74.5	12,714	23.7%	N/A	47.4%				N/A	N/A	N/A	
3	Martin 3												
4	Gas		43,320				7,818	338,676	1,000,000	338,676	1,396,579	3.22	4.12
5	Plant Unit Info	492	43,320	12.2%	90.6%	65.2%	7,818			338,676	1,396,579	3.22	
6	Martin 4												
7	Gas		35,302				8,197	289,370	1,000,000	289,370	1,193,154	3.38	4.12
8	Plant Unit Info	492	35,302	10.0%	94.0%	82.5%	8,197			289,370	1,193,154	3.38	
9	Martin 8 Solar												
10	Solar		4,340				N/A	N/A	N/A	N/A	N/A	N/A	N/A
11	Plant Unit Info	75.0	4,340	8.0%	N/A	20.7%				N/A	N/A	N/A	
12	Martin 8												
13	Light Oil		-				-	-	-	-	-	-	-
14	Gas		201,658				7,516	1,515,756	1,000,000	1,515,756	6,251,252	3.10	4.12
15	Plant Unit Info	1,258	201,658	22.3%	60.7%	71.6%	7,516			1,515,756	6,251,252	3.10	
16	Miami-Dade PV Solar												
17	Solar		13,058				N/A	N/A	N/A	N/A	N/A	N/A	N/A
18	Plant Unit Info	74.5	13,058	24.3%	N/A	53.1%				N/A	N/A	N/A	
19	Northern Preserve PV Solar												
20	Solar		11,955				N/A	N/A	N/A	N/A	N/A	N/A	N/A
21	Plant Unit Info	74.5	11,955	22.3%	N/A	48.6%				N/A	N/A	N/A	
22	Okechobee 1												
23	Light Oil		-				-	-	-	-	-	-	-
24	Gas		1,063,609				6,264	6,662,635	1,000,000	6,662,635	27,569,915	2.59	4.14
25	Plant Unit Info	1,655	1,063,609	89.3%	96.7%	89.3%	6,264			6,662,635	27,569,915	2.59	
26	Okeechobee PV Solar												
27	Solar		12,724				N/A	N/A	N/A	N/A	N/A	N/A	N/A
28	Plant Unit Info	74.5	12,724	23.7%	N/A	51.8%				N/A	N/A	N/A	
29	PEEC												
30	Light Oil		-				-	-	-	-	-	-	-
31	Gas		725,326				6,370	4,620,094	1,000,000	4,620,094	19,250,265	2.65	4.17
32	Plant Unit Info	1,283	725,326	78.5%	82.8%	78.5%	6,370			4,620,094	19,250,265	2.65	
33	Pioneer Trail PV Solar												
34	Solar		12,082				N/A	N/A	N/A	N/A	N/A	N/A	N/A
35	Plant Unit Info	74.5	12,082	22.5%	N/A	49.1%				N/A	N/A	N/A	
36	Riviera 5												
37	Light Oil		-				-	-	-	-	-	-	-
38	Gas		671,438				6,687	4,489,588	1,000,000	4,489,588	18,577,869	2.77	4.14

ESTIMATED FOR THE PERIOD OF: JULY 2020 THROUGH DECEMBER 2020

(1) Line No.	(2) FCR - E-4 Schedule	(3) Net Capability (MW)	(4) Net Generation (MWH)	(5) Capacity Factor (%)	(6) Equivalent Availability Factor (%)	(7) Net Output Factor (%)	(8) Avg Net Heat Rate (BTU/KWH)	(9) Fuel Burned (Units)	(10) Fuel Heat Value (BTU/unit)	(11) Fuel Burned (MMBTU)	(12) As Burned Fuel Cost ($)	(13) Fuel Cost per KWH (cents/KWH)	(14) Cost of Fuel ($/Unit)
1	Plant Unit Info	1,326	671,438	70.3%	93.9%	70.3%	6,687			4,489,588	18,577,869	2.77	
2	Sanford 4												
3	Gas		90,772				7,534	683,886	1,000,000	683,886	2,847,929	3.14	4.16
4	Plant Unit Info	1,192	90,772	10.6%	94.0%	53.3%	7,534			683,886	2,847,929	3.14	
5	Sanford 5												
6	Gas		407,820				7,106	2,898,022	1,000,000	2,898,022	12,071,895	2.96	4.17
7	Plant Unit Info	1,192	407,820	47.5%	94.0%	47.5%	7,106			2,898,022	12,071,895	2.96	
8	Scherer 4												
9	Coal		171,897					116,073	17,000,000	1,973,249	5,071,701	2.95	43.69
10	Plant Unit Info	626	171,897	38.1%	94.8%	38.1%	11,479			1,973,249	5,071,701	2.95	
11	Southfork PV Solar												
12	Solar		14,045				N/A	N/A	N/A	N/A	N/A	N/A	N/A
13	Plant Unit Info	74.5	14,045	26.2%	N/A	57.1%				N/A	N/A	N/A	
14	Space Coast												
15	Solar		1,255				N/A	N/A	N/A	N/A	N/A	N/A	N/A
16	Plant Unit Info	10.0	1,255	17.4%	N/A	34.9%				N/A	N/A	N/A	
17	St Lucie 1												
18	Nuclear		704,121					7,272,374	1,000,000	7,272,374	3,508,920	0.50	0.48
19	Plant Unit Info	1,003	704,121	97.5%	97.5%	97.5%	10,328			7,272,374	3,508,920	0.50	
20	St Lucie 2												
21	Nuclear		603,399					6,188,882	1,000,000	6,188,882	2,685,975	0.45	0.43
22	Plant Unit Info	860	603,399	97.5%	97.5%	97.5%	10,257			6,188,882	2,685,975	0.45	
23	Sunshine Gateway PV Solar												
24	Solar		12,701				N/A	N/A	N/A	N/A	N/A	N/A	N/A
25	Plant Unit Info	74.5	12,701	23.7%	N/A	51.7%				N/A	N/A	N/A	
26	Sweet Bay PV Solar												
27	Solar		11,706				N/A	N/A	N/A	N/A	N/A	N/A	N/A
28	Plant Unit Info	74.5	11,706	21.8%	N/A					N/A	N/A	N/A	
29	Turkey Point 3												
30	Nuclear		603,000					6,356,404	1,000,000	6,356,404	3,059,808	0.51	0.48
31	Plant Unit Info	859	603,000	97.5%	97.5%	97.5%	10,541			6,356,404	3,059,808	0.51	
32	Turkey Point 4												
33	Nuclear		446,928					4,662,353	1,000,000	4,662,353	2,690,644	0.60	0.58
34	Plant Unit Info	848	446,928	73.2%	71.0%	89.4%	10,432			4,662,353	2,690,644	0.60	
35	Turkey Point 5												
36	Light Oil		-				-	-	-	-	-	-	-
37	Gas		277,493				7,405	2,054,832	1,000,000	2,054,832	8,561,784	3.09	4.17
38	Plant Unit Info	1,294	277,493	29.8%	94.0%	59.2%	7,405			2,054,832	8,561,784	3.09	

ESTIMATED FOR THE PERIOD OF: JULY 2020 THROUGH DECEMBER 2020

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.	FCR - E-4 Schedule	Net Capability (MW)	Net Generation (MWH)	Capacity Factor (%)	Equivalent Availability Factor (%)	Net Output Factor (%)	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost ($)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel ($/Unit)
1	Twin Lakes PV Solar												
2	Solar		11,832				N/A	N/A	N/A	N/A	N/A	N/A	N/A
3	Plant Unit Info	74.5	11,832	22.1%	N/A	48.1%				N/A	N/A	N/A	
4	WCEC 01												
5	Light Oil		-				-	-	-	-	-	-	-
6	Plant Unit Info	0	-	N/A	N/A	N/A	-			-	-	-	
7	WCEC 02												
8	Light Oil		-				-	-	-	-	-	-	-
9	Gas		686,104				6,687	4,588,025	1,000,000	4,588,025	18,950,329	2.76	4.13
10	Plant Unit Info	1,248	686,104	76.4%	93.9%	76.4%	6,687			4,588,025	18,950,329	2.76	
11	WCEC 03												
12	Light Oil		-				-	-	-	-	-	-	-
13	Gas		676,886				6,753	4,570,781	1,000,000	4,570,781	18,881,477	2.79	4.13
14	Plant Unit Info	1,254	676,886	75.0%	93.9%	75.0%	6,753			4,570,781	18,881,477	2.79	
15	Wildflower PV Solar												
16	Solar		13,864				N/A	N/A	N/A	N/A	N/A	N/A	N/A
17	Plant Unit Info	74.5	13,864	25.9%	N/A	56.4%				N/A	N/A	N/A	
18	System Totals												
19	Plant Unit Info	25,676	9,046,085				7,590			68,657,243	192,292,179	2.13	
20													
21													
22													
23													
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25													
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ESTIMATED FOR THE PERIOD OF: JULY 2020 THROUGH DECEMBER 2020

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.	FCR - E-4 Schedule	Net Capability (MW)	Net Generation (MWH)	Capacity Factor (%)	Equivalent Availability Factor (%)	Net Output Factor (%)	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost ($)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel ($/Unit)
1	**Dec - 2020**												
2	Babcock Preserve PV Solar												
3	Solar		12,564				N/A	N/A	N/A	N/A	N/A	N/A	N/A
4	Plant Unit Info	74.5	12,564	22.7%	N/A	49.5%				N/A	N/A	N/A	
5	Babcock PV Solar												
6	Solar		11,786				N/A	N/A	N/A	N/A	N/A	N/A	N/A
7	Plant Unit Info	74.5	11,786	21.3%	N/A	46.4%				N/A	N/A	N/A	
8	Barefoot Bay PV Solar												
9	Solar		11,620				N/A	N/A	N/A	N/A	N/A	N/A	N/A
10	Plant Unit Info	74.5	11,620	21.0%	N/A	45.7%				N/A	N/A	N/A	
11	Blue Cypress PV Solar												
12	Solar		12,043				N/A	N/A	N/A	N/A	N/A	N/A	N/A
13	Plant Unit Info	74.5	12,043	21.7%	N/A	47.4%				N/A	N/A	N/A	
14	Blue Heron PV Solar												
15	Solar		12,564				N/A	N/A	N/A	N/A	N/A	N/A	N/A
16	Plant Unit Info	74.5	12,564	22.7%	N/A	49.5%				N/A	N/A	N/A	
17	Cattle Ranch PV Solar												
18	Solar		10,595				N/A	N/A	N/A	N/A	N/A	N/A	N/A
19	Plant Unit Info	74.5	10,595	19.1%	N/A	41.7%				N/A	N/A	N/A	
20	CCEC 3												
21	Light Oil		-				-	-	-	-	-	-	-
22	Gas		526,137				6,761	3,556,964	1,000,000	3,556,964	16,856,174	3.20	4.74
23	Plant Unit Info	1,326	526,137	53.3%	93.9%	53.3%	6,761			3,556,964	16,856,174	3.20	
24	Citrus PV Solar												
25	Solar		11,757				N/A	N/A	N/A	N/A	N/A	N/A	N/A
26	Plant Unit Info	74.5	11,757	21.2%	N/A	46.3%				N/A	N/A	N/A	
27	Coral Farms PV Solar												
28	Solar		12,061				N/A	N/A	N/A	N/A	N/A	N/A	N/A
29	Plant Unit Info	74.5	12,061	21.8%	N/A	47.5%				N/A	N/A	N/A	
30	Desoto Solar												
31	Solar		2,906				N/A	N/A	N/A	N/A	N/A	N/A	N/A
32	Plant Unit Info	25.0	2,906	15.6%	N/A	34.1%				N/A	N/A	N/A	
33	Echo River PV Solar												
34	Solar		10,814				N/A	N/A	N/A	N/A	N/A	N/A	N/A
35	Plant Unit Info	74.5	10,814	19.5%	N/A	42.6%				N/A	N/A	N/A	
36	Fort Myers GT												
37	Light Oil		-				-	-	-	-	-	-	-
38	Gas		-				-	-	-	-	-	-	-

ESTIMATED FOR THE PERIOD OF: JULY 2020 THROUGH DECEMBER 2020

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.	FCR - E-4 Schedule	Net Capability (MW)	Net Generation (MWH)	Capacity Factor (%)	Equivalent Availability Factor (%)	Net Output Factor (%)	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost ($)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel ($/Unit)
1	Plant Unit Info	0	-	N/A	N/A	N/A	-			-	-	-	
2	Fort Myers 2												
3	Gas		608,721				7,380	4,492,519	1,000,000	4,492,519	21,290,908	3.50	4.74
4	Plant Unit Info	1,770	608,721	46.2%	89.2%	46.2%	7,380			4,492,519	21,290,908	3.50	
5	Fort Myers 3A												
6	Light Oil		450				16,229	1,253	5,830,000	7,303	110,957	24.66	88.58
7	Gas		-				-	-	-	-	-	-	-
8	Plant Unit Info	189	450	0.3%	48.3%	47.6%	16,229			7,303	110,957	24.66	
9	Fort Myers 3B												
10	Light Oil		-				-	-	-	-	-	-	-
11	Gas		-				-	-	-	-	-	-	-
12	Plant Unit Info	0	-	N/A	N/A	N/A	-			-	-	-	
13	Fort Myers 3C												
14	Light Oil		-				-	-	-	-	-	-	-
15	Gas		908				11,128	10,104	1,000,000	10,104	47,854	5.27	4.74
16	Plant Unit Info	221	908	0.6%	93.5%	81.8%	11,128			10,104	47,854	5.27	
17	Fort Myers 3D												
18	Light Oil		-				-	-	-	-	-	-	-
19	Gas		1,586				11,880	18,842	1,000,000	18,842	89,237	5.63	4.74
20	Plant Unit Info	221	1,586	1.0%	93.5%	71.4%	11,880			18,842	89,237	5.63	
21	Hammock PV Solar												
22	Solar		12,892				N/A	N/A	N/A	N/A	N/A	N/A	N/A
23	Plant Unit Info	74.5	12,892	23.3%	N/A	50.7%				N/A	N/A	N/A	
24	Hibiscus PV Solar												
25	Solar		11,247				N/A	N/A	N/A	N/A	N/A	N/A	N/A
26	Plant Unit Info	74.5	11,247	20.3%	N/A	44.3%				N/A	N/A	N/A	
27	Horizon PV Solar												
28	Solar		12,148				N/A	N/A	N/A	N/A	N/A	N/A	N/A
29	Plant Unit Info	74.5	12,148	21.9%	N/A	47.8%				N/A	N/A	N/A	
30	Indiantown FPL												
31	Coal		-					-	-	-	-	-	-
32	Plant Unit Info	0	-	N/A	N/A	N/A	-			-	-	-	
33	Indian River PV Solar												
34	Solar		12,031				N/A	N/A	N/A	N/A	N/A	N/A	N/A
35	Plant Unit Info	74.5	12,031	21.7%	N/A	47.4%				N/A	N/A	N/A	
36	Interstate PV Solar												
37	Solar		11,611				N/A	N/A	N/A	N/A	N/A	N/A	N/A
38	Plant Unit Info	74.5	11,611	21.0%	N/A	45.7%				N/A	N/A	N/A	

ESTIMATED FOR THE PERIOD OF: JULY 2020 THROUGH DECEMBER 2020

(1) Line No.	(2) FCR - E-4 Schedule	(3) Net Capability (MW)	(4) Net Generation (MWH)	(5) Capacity Factor (%)	(6) Equivalent Availability Factor (%)	(7) Net Output Factor (%)	(8) Avg Net Heat Rate (BTU/KWH)	(9) Fuel Burned (Units)	(10) Fuel Heat Value (BTU/unit)	(11) Fuel Burned (MMBTU)	(12) As Burned Fuel Cost ($)	(13) Fuel Cost per KWH (cents/KWH)	(14) Cost of Fuel ($/Unit)
1	Lauderdale GT												
2	Light Oil		-				-	-	-	-	-	-	-
3	Gas		-				-	-	-	-	-	-	-
4	Plant Unit Info	0	-	N/A	N/A	N/A	-			-	-	-	
5	Lauderdale 6A												
6	Light Oil		-				-	-	-	-	-	-	-
7	Gas		3,030				10,599	32,116	1,000,000	32,116	152,104	5.02	4.74
8	Plant Unit Info	218	3,030	1.9%	93.5%	92.7%	10,599			32,116	152,104	5.02	
9	Lauderdale 6B												
10	Light Oil		-				-	-	-	-	-	-	-
11	Gas		3,030				10,599	32,116	1,000,000	32,116	152,104	5.02	4.74
12	Plant Unit Info	218	3,030	1.9%	93.5%	92.7%	10,599			32,116	152,104	5.02	
13	Lauderdale 6C												
14	Gas		-				-	-	-	-	-	-	-
15	Plant Unit Info	0	-	N/A	N/A	N/A	-			-	-	-	
16	Lauderdale 6D												
17	Light Oil		-				-	-	-	-	-	-	-
18	Gas		-				-	-	-	-	-	-	-
19	Plant Unit Info	0	-	N/A	N/A	N/A	-			-	-	-	
20	Lauderdale 6E												
21	Light Oil		-				-	-	-	-	-	-	-
22	Gas		-				-	-	-	-	-	-	-
23	Plant Unit Info	0	-	N/A	N/A	N/A	-			-	-	-	
24	Loggerhead PV Solar												
25	Solar		12,343				N/A	N/A	N/A	N/A	N/A	N/A	N/A
26	Plant Unit Info	74.5	12,343	22.3%	N/A	48.6%				N/A	N/A	N/A	
27	Manatee 1												
28	Heavy Oil		-					-	-	-	-	-	-
29	Plant Unit Info	0	-	N/A	N/A	N/A	-			-	-	-	
30	Manatee 3												
31	Gas		149,703				8,012	1,199,460	1,000,000	1,199,460	5,632,652	3.76	4.70
32	Plant Unit Info	1,254	149,703	16.1%	94.1%	66.3%	8,012			1,199,460	5,632,652	3.76	
33	Manatee PV Solar												
34	Solar		11,751				N/A	N/A	N/A	N/A	N/A	N/A	N/A
35	Plant Unit Info	74.5	11,751	21.2%	N/A	46.3%				N/A	N/A	N/A	
36	Martin 3												
37	Gas		75,921				7,796	591,850	1,000,000	591,850	2,779,748	3.66	4.70
38	Plant Unit Info	492	75,921	20.7%	52.0%	35.7%	7,796			591,850	2,779,748	3.66	

ESTIMATED FOR THE PERIOD OF: JULY 2020 THROUGH DECEMBER 2020

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.	FCR - E-4 Schedule	Net Capability (MW)	Net Generation (MWH)	Capacity Factor (%)	Equivalent Availability Factor (%)	Net Output Factor (%)	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost ($)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel ($/Unit)
1	Martin 4												
2	Gas		12,599				9,371	118,071	1,000,000	118,071	554,460	4.40	4.70
3	Plant Unit Info	492	12,599	3.4%	94.0%	73.2%	9,371			118,071	554,460	4.40	
4	Martin 8 Solar												
5	Solar		5,425				N/A	N/A	N/A	N/A	N/A	N/A	N/A
6	Plant Unit Info	75.0	5,425	9.7%	N/A	17.9%				N/A	N/A	N/A	
7	Martin 8												
8	Light Oil		-				-	-	-	-	-	-	-
9	Gas		116,979				8,143	952,567	1,000,000	952,567	4,473,389	3.82	4.70
10	Plant Unit Info	1,258	116,979	12.5%	94.0%	65.9%	8,143			952,567	4,473,389	3.82	
11	Miami-Dade PV Solar												
12	Solar		12,413				N/A	N/A	N/A	N/A	N/A	N/A	N/A
13	Plant Unit Info	74.5	12,413	22.4%	N/A	48.9%				N/A	N/A	N/A	
14	Northern Preserve PV Solar												
15	Solar		10,920				N/A	N/A	N/A	N/A	N/A	N/A	N/A
16	Plant Unit Info	74.5	10,920	19.7%	N/A	43.0%				N/A	N/A	N/A	
17	Okechobee 1												
18	Light Oil		-				-	-	-	-	-	-	-
19	Gas		1,056,720				6,285	6,641,050	1,000,000	6,641,050	31,376,710	2.97	4.72
20	Plant Unit Info	1,655	1,056,720	85.8%	96.7%	85.8%	6,285			6,641,050	31,376,710	2.97	
21	Okeechobee PV Solar												
22	Solar		11,539				N/A	N/A	N/A	N/A	N/A	N/A	N/A
23	Plant Unit Info	74.5	11,539	20.8%	N/A	45.4%				N/A	N/A	N/A	
24	PEEC												
25	Light Oil		-				-	-	-	-	-	-	-
26	Gas		836,483				6,352	5,313,265	1,000,000	5,313,265	25,179,518	3.01	4.74
27	Plant Unit Info	1,283	836,483	87.6%	93.9%	87.6%	6,352			5,313,265	25,179,518	3.01	
28	Pioneer Trail PV Solar												
29	Solar		11,197				N/A	N/A	N/A	N/A	N/A	N/A	N/A
30	Plant Unit Info	74.5	11,197	20.2%	N/A	44.1%				N/A	N/A	N/A	
31	Riviera 5												
32	Light Oil		-				-	-	-	-	-	-	-
33	Gas		570,444				6,744	3,846,879	1,000,000	3,846,879	18,175,198	3.19	4.72
34	Plant Unit Info	1,326	570,444	57.8%	93.9%	57.8%	6,744			3,846,879	18,175,198	3.19	
35	Sanford 4												
36	Gas		37,565				8,360	314,034	1,000,000	314,034	1,488,201	3.96	4.74
37	Plant Unit Info	1,192	37,565	4.2%	94.0%	47.8%	8,360			314,034	1,488,201	3.96	
38	Sanford 5												

ESTIMATED FOR THE PERIOD OF: JULY 2020 THROUGH DECEMBER 2020

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.	FCR - E-4 Schedule	Net Capability (MW)	Net Generation (MWH)	Capacity Factor (%)	Equivalent Availability Factor (%)	Net Output Factor (%)	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost ($)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel ($/Unit)
1	Gas		348,380				7,267	2,531,632	1,000,000	2,531,632	11,998,382	3.44	4.74
2	Plant Unit Info	1,192	348,380	39.3%	94.0%	39.3%	7,267			2,531,632	11,998,382	3.44	
3	Scherer 4												
4	Coal		177,176					119,700	17,000,000	2,034,894	5,212,506	2.94	43.55
5	Plant Unit Info	626	177,176	38.0%	94.8%	38.0%	11,485			2,034,894	5,212,506	2.94	
6	Southfork PV Solar												
7	Solar		12,295				N/A	N/A	N/A	N/A	N/A	N/A	N/A
8	Plant Unit Info	74.5	12,295	22.2%	N/A	48.4%				N/A	N/A	N/A	
9	Space Coast												
10	Solar		1,170				N/A	N/A	N/A	N/A	N/A	N/A	N/A
11	Plant Unit Info	10.0	1,170	15.7%	N/A	34.3%				N/A	N/A	N/A	
12	St Lucie 1												
13	Nuclear		727,591					7,514,787	1,000,000	7,514,787	3,625,884	0.50	0.48
14	Plant Unit Info	1,003	727,591	97.5%	97.5%	97.5%	10,328			7,514,787	3,625,884	0.50	
15	St Lucie 2												
16	Nuclear		623,512					6,395,178	1,000,000	6,395,178	2,775,507	0.45	0.43
17	Plant Unit Info	860	623,512	97.5%	97.5%	97.5%	10,257			6,395,178	2,775,507	0.45	
18	Sunshine Gateway PV Solar												
19	Solar		10,864				N/A	N/A	N/A	N/A	N/A	N/A	N/A
20	Plant Unit Info	74.5	10,864	19.6%	N/A	42.8%				N/A	N/A	N/A	
21	Sweet Bay PV Solar												
22	Solar		10,858				N/A	N/A	N/A	N/A	N/A	N/A	N/A
23	Plant Unit Info	74.5	10,858	19.6%	N/A					N/A	N/A	N/A	
24	Turkey Point 3												
25	Nuclear		623,100					6,568,284	1,000,000	6,568,284	3,161,801	0.51	0.48
26	Plant Unit Info	859	623,100	97.5%	97.5%	97.5%	10,541			6,568,284	3,161,801	0.51	
27	Turkey Point 4												
28	Nuclear		629,647					6,568,480	1,000,000	6,568,480	3,790,670	0.60	0.58
29	Plant Unit Info	868	629,647	97.5%	96.9%	97.5%	10,432			6,568,480	3,790,670	0.60	
30	Turkey Point 5												
31	Light Oil		-				-	-	-	-	-	-	-
32	Gas		253,974				7,441	1,889,773	1,000,000	1,889,773	8,956,511	3.53	4.74
33	Plant Unit Info	1,294	253,974	26.4%	61.7%	34.1%	7,441			1,889,773	8,956,511	3.53	
34	Twin Lakes PV Solar												
35	Solar		10,310				N/A	N/A	N/A	N/A	N/A	N/A	N/A
36	Plant Unit Info	74.5	10,310	18.6%	N/A	40.6%				N/A	N/A	N/A	
37	WCEC 01												
38	Light Oil		-				-	-	-	-	-	-	-

ESTIMATED FOR THE PERIOD OF: JULY 2020 THROUGH DECEMBER 2020

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.	FCR - E-4 Schedule	Net Capability (MW)	Net Generation (MWH)	Capacity Factor (%)	Equivalent Availability Factor (%)	Net Output Factor (%)	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost ($)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel ($/Unit)
1	Gas		259,020				6,863	1,777,731	1,000,000	1,777,731	8,348,208	3.22	4.70
2	Plant Unit Info	1,248	259,020	27.9%	48.7%	53.4%	6,863			1,777,731	8,348,208	3.22	
3	WCEC 02												
4	Light Oil		-				-	-	-	-	-	-	-
5	Gas		618,016				6,741	4,165,874	1,000,000	4,165,874	19,562,902	3.17	4.70
6	Plant Unit Info	1,248	618,016	66.6%	93.9%	66.6%	6,741			4,165,874	19,562,902	3.17	
7	WCEC 03												
8	Light Oil		-				-	-	-	-	-	-	-
9	Gas		604,280				6,803	4,111,160	1,000,000	4,111,160	19,305,966	3.19	4.70
10	Plant Unit Info	1,254	604,280	64.8%	93.9%	64.8%	6,803			4,111,160	19,305,966	3.19	
11	Wildflower PV Solar												
12	Solar		12,684				N/A	N/A	N/A	N/A	N/A	N/A	N/A
13	Plant Unit Info	74.5	12,684	22.9%	N/A	49.9%				N/A	N/A	N/A	
14	System Totals												
15	Plant Unit Info	25,540	9,167,380				7,710			70,684,933	215,097,553	2.35	
16													
17													
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ESTIMATED FOR THE PERIOD OF: JULY 2020 THROUGH DECEMBER 2020

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
Line No.	FCR - E-5 Schedule	Jul - 2020	Aug - 2020	Sep - 2020	Oct - 2020	Nov - 2020	Dec - 2020	Total
1	**#6 Heavy Oil (BBLS)**							
2	Purchases							
3	Units	-	-	-	-	130,000	-	130,000
4	Unit Cost	-	-	-	-	55.5538	-	55.5538
5	Amount	-	-	-	-	$7,222,000	-	$7,222,000
6								
7	Burned							
8	Units	22,114	37,875	51,055	55,087	5,955	-	172,087
9	Unit Cost	72.9904	72.9904	67.1412	67.1412	67.1412	-	69.1802
10	Amount	$1,614,126	$2,764,546	$3,427,903	$3,698,618	$399,826	-	$11,905,019
11								
12	Ending Inventory							
13	Units	555,055	517,179	466,124	411,037	535,082	535,082	535,082
14	Unit Cost	72.9910	72.9902	72.9913	72.9910	68.8007	68.8007	68.8007
15	Amount	$40,514,000	$37,749,000	$34,023,000	$30,002,000	$36,814,000	$36,814,000	$36,814,000
16								
17	**#2 Light Oil (BBLS)**							
18	Purchases							
19	Units	11,000	-	39,978	78,926	-	-	129,904
20	Unit Cost	56.8182	-	58.0817	58.8779	-	-	58.4584
21	Amount	$625,000	-	$2,322,000	$4,647,000	-	-	$7,594,000
22								
23	Burned							
24	Units	9,192	19,665	44,142	52,522	58	1,253	126,831
25	Unit Cost	80.5757	80.1098	72.3788	70.6513	88.5745	88.5772	73.6235
26	Amount	$740,619	$1,575,333	$3,194,970	$3,710,718	$5,120	$110,957	$9,337,717
27								
28	Ending Inventory							
29	Units	1,413,617	1,393,953	1,389,789	1,416,193	1,416,135	1,414,883	1,414,883
30	Unit Cost	92.0843	92.1975	91.5808	90.2998	90.3000	90.3008	90.3008
31	Amount	$130,172,000	$128,519,000	$127,278,000	$127,882,000	$127,877,000	$127,765,000	$127,765,000
32								
33	**Coal - Scherer (MMBTU)**							
34	Purchases							
35	Units	2,128,054	2,128,054	2,128,054	2,128,054	2,128,054	2,128,054	12,768,322
36	Unit Cost	2.4910	2.4943	2.4943	2.4981	2.5075	2.5234	2.5014
37	Amount	$5,301,000	$5,308,000	$5,308,000	$5,316,000	$5,336,000	$5,370,000	$31,939,000
38								
39	Burned							
40	Units	2,112,010	2,197,826	2,151,007	2,299,336	1,973,249	2,034,894	12,768,322
41	Unit Cost	2.6417	2.6208	2.6012	2.5836	2.5702	2.5616	2.5970
42	Amount	$5,579,326	$5,760,044	$5,595,270	$5,940,492	$5,071,701	$5,212,506	$33,159,339
43								
44	Ending Inventory							
45	Units	5,970,458	5,900,685	5,877,732	5,706,450	5,861,254	5,954,414	5,954,414
46	Unit Cost	2.6629	2.6187	2.5857	2.5624	2.5476	2.5411	2.5411
47	Amount	$15,899,000	$15,452,000	$15,198,000	$14,622,000	$14,932,000	$15,131,000	$15,131,000
48								
49	**Gas (MCF)**							
50	Burned							
51	Units	63,397,723	64,315,948	58,146,869	56,404,861	42,165,532	41,596,007	326,026,940
52	Unit Cost	3.0067	3.0935	3.1542	3.3412	4.1472	4.7221	3.4744
53	Amount	$190,617,418	$198,964,403	$183,407,317	$188,459,177	$174,870,185	$196,420,227	$1,132,738,727
54								
55	**Nuclear (Other)**							
56	Burned							
57	Units	27,046,601	27,046,601	26,139,306	20,871,266	24,480,013	27,046,729	152,630,515
58	Unit Cost	0.4750	0.4750	0.4749	0.4676	0.4880	0.4937	0.4794
59	Amount	$12,846,072	$12,846,072	$12,414,277	$9,759,639	$11,945,347	$13,353,862	$73,165,269
60								

ESTIMATED FOR THE PERIOD OF: JULY 2020 THROUGH DECEMBER 2020

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Line No.	FCR - E-6 Schedule	Type & Schedule	Total KWH Sold (000)	KWH from Own Generation (000)	Fuel Cost (cents/KWH)	Total Cost (cents/KWH)	Total $ for Fuel Adjustment (Col (5)*Col(6))	Total Cost ($) (Col (5)*Col(7))	Gain from Off System Sales ($)
1	**July Estimated**								
2	Off System	OS	154,070	154,070	1.680	2.884	2,588,041	4,443,824	1,393,573
3	St Lucie Reliability Sales		52,997	52,997	0.538	0.538	285,148	285,148	-
4	**Subtotal July Estimated**		207,067	207,067	1.388	2.284	$2,873,189	$4,728,971	$1,393,573
5									
6	**August Estimated**								
7	Off System	OS	158,720	158,720	1.819	2.987	2,887,433	4,741,610	1,378,017
8	St Lucie Reliability Sales		52,997	52,997	0.538	0.538	285,148	285,148	-
9	**Subtotal August Estimated**		211,717	211,717	1.498	2.374	$3,172,581	$5,026,758	$1,378,017
10									
11	**September Estimated**								
12	Off System	OS	145,500	145,500	2.084	3.381	3,032,109	4,919,284	1,450,675
13	St Lucie Reliability Sales		51,288	51,288	0.538	0.538	275,949	275,949	-
14	**Subtotal September Estimated**		196,788	196,788	1.681	2.640	$3,308,058	$5,195,233	$1,450,675
15									
16	**October Estimated**								
17	Off System	OS	145,390	145,390	2.422	3.691	3,521,492	5,366,750	1,409,088
18	St Lucie Reliability Sales		52,997	52,997	0.538	0.538	285,148	285,148	-
19	**Subtotal October Estimated**		198,387	198,387	1.919	2.849	$3,806,639	$5,651,897	$1,409,088
20									
21	**November Estimated**								
22	Off System	OS	194,100	194,100	1.749	2.789	3,395,175	5,412,706	1,435,231
23	St Lucie Reliability Sales		52,441	52,441	0.515	0.515	269,916	269,916	-
24	**Subtotal November Estimated**		246,541	246,541	1.487	2.305	$3,665,091	$5,682,622	$1,435,231
25									
26	**December Estimated**								
27	Off System	OS	249,550	249,550	1.888	3.083	4,710,794	7,692,399	1,912,955
28	St Lucie Reliability Sales		54,189	54,189	0.515	0.515	278,913	278,913	-
29	**Subtotal December Estimated**		303,739	303,739	1.643	2.624	$4,989,707	$7,971,312	$1,912,955
30									
31	**Period Total**								
32	Off System	OS	1,047,330	1,047,330	1.923	3.110	20,135,044	32,576,573	8,979,539
33	St Lucie Reliability Sales		316,910	316,910	0.530	0.530	1,680,221	1,680,221	-
34	**Subtotal Period Total**		1,364,240	1,364,240	1.599	2.511	$21,815,265	$34,256,794	$8,979,539
35									

ESTIMATED FOR THE PERIOD OF: JULY 2020 THROUGH DECEMBER 2020

(1) Line No.	(2) PURCHASED FROM	(3) Type & Schedule	(4) KWH Purchased (000)	(5) KWH for Firm	(6) Fuel Cost (cents/KWH)	(7) Total $ for Fuel Adj
1	**July Estimated**					
2	OUC		5,767	5,767	2.706	156,051
3	St Lucie Reliability		53,318	53,318	0.478	254,911
4	SWA		74,750	74,750	2.536	1,895,802
5	**Subtotal July Estimated**		133,835	133,835	1.724	2,306,763
6						
7	**August Estimated**					
8	OUC		8,629	8,629	2.788	240,540
9	St Lucie Reliability		53,318	53,318	0.478	254,911
10	SWA		65,926	65,926	2.593	1,709,761
11	**Subtotal August Estimated**		127,873	127,873	1.725	2,205,211
12						
13	**September Estimated**					
14	OUC		9,909	9,909	2.819	279,308
15	St Lucie Reliability		51,598	51,598	0.478	246,688
16	SWA		73,253	73,253	2.776	2,033,217
17	**Subtotal September Estimated**		134,760	134,760	1.899	2,559,213
18						
19	**October Estimated**					
20	OUC		6,862	6,862	2.900	198,980
21	St Lucie Reliability		53,318	53,318	0.478	254,911
22	SWA		64,081	64,081	2.889	1,851,565
23	**Subtotal October Estimated**		124,261	124,261	1.855	2,305,455
24						
25	**November Estimated**					
26	OUC		800	800	3.281	26,250
27	St Lucie Reliability		52,806	52,806	0.457	241,095
28	SWA		73,800	73,800	2.917	2,153,033
29	**Subtotal November Estimated**		127,406	127,406	1.900	2,420,378
30						
31	**December Estimated**					
32	OUC		722	722	3.745	27,036
33	St Lucie Reliability		54,566	54,566	0.457	249,132
34	SWA		75,293	75,293	2.850	2,145,913
35	**Subtotal December Estimated**		130,581	130,581	1.855	2,422,081
36						
37	**Period Total**					
38	OUC		32,689	32,689	2.839	928,165
39	St Lucie Reliability		318,924	318,924	0.471	1,501,647
40	SWA		427,102	427,102	2.760	11,789,290
41	**Subtotal Period Total**		778,715	778,715	1.826	14,219,102
42						

ESTIMATED FOR THE PERIOD OF: JULY 2020 THROUGH DECEMBER 2020

(1)	(2)	(3)	(4)	(5)	(6)	(7)
Line No.	PURCHASED FROM	Type & Schedule	Total KWH Purchased (000)	KWH For Firm (000)	Fuel Cost (cents/KWH)	Total $ for Fuel Adj
1	**July Estimated**					
2	Qualifying Facilities		23,592	23,592	1.419	$334,819
3	**Subtotal July Estimated**		23,592	23,592	1.419	$334,819
4						
5	**August Estimated**					
6	Qualifying Facilities		20,639	20,639	1.540	$317,785
7	**Subtotal August Estimated**		20,639	20,639	1.540	$317,785
8						
9	**September Estimated**					
10	Qualifying Facilities		27,367	27,367	1.659	$454,126
11	**Subtotal September Estimated**		27,367	27,367	1.659	$454,126
12						
13	**October Estimated**					
14	Qualifying Facilities		27,662	27,662	1.928	$533,452
15	**Subtotal October Estimated**		27,662	27,662	1.928	$533,452
16						
17	**November Estimated**					
18	Qualifying Facilities		27,086	27,086	1.666	$451,378
19	**Subtotal November Estimated**		27,086	27,086	1.666	$451,378
20						
21	**December Estimated**					
22	Qualifying Facilities		30,006	30,006	1.870	$561,069
23	**Subtotal December Estimated**		30,006	30,006	1.870	$561,069
24						
25	**Period Total**					
26	Qualifying Facilities		156,352	156,352	1.697	$2,652,629
27	**Subtotal Period Total**		156,352	156,352	1.697	$2,652,629
28						

ESTIMATED FOR THE PERIOD OF: JULY 2020 THROUGH DECEMBER 2020

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
Line No.	PURCHASED FROM	Type & Schedule	Total KWH Purchased (000)	Transaction Cost (cents/KWH)	Total ($) for Fuel Adj (Col(4)*Col(5))	Cost if Generated (cents/KWH)	Cost if Generated ($) (Col(4)*Col(7))	Fuel Savings ($) (Col(8)-Col(6))
1	**July Estimated**							
2	Economy	OS	74,710	2.900	$2,166,590	3.219	$2,404,552	$237,962
3	**Subtotal July Estimated**		74,710	2.900	$2,166,590	3.219	$2,404,552	$237,962
4								
5	**August Estimated**							
6	Economy	OS	62,310	2.900	$1,806,990	3.239	$2,018,094	$211,104
7	**Subtotal August Estimated**		62,310	2.900	$1,806,990	3.239	$2,018,094	$211,104
8								
9	**September Estimated**							
10	Economy	OS	82,200	2.600	$2,137,200	2.888	$2,374,260	$237,060
11	**Subtotal September Estimated**		82,200	2.600	$2,137,200	2.888	$2,374,260	$237,060
12								
13	**October Estimated**							
14	Economy	OS	47,430	2.400	$1,138,320	2.828	$1,341,274	$202,954
15	**Subtotal October Estimated**		47,430	2.400	$1,138,320	2.828	$1,341,274	$202,954
16								
17	**November Estimated**							
18	Economy	OS	2,400	1.750	$42,000	1.910	$45,828	$3,828
19	**Subtotal November Estimated**		2,400	1.750	$42,000	1.910	$45,828	$3,828
20								
21	**December Estimated**							
22	Economy	OS	1,550	1.750	$27,125	1.904	$29,518	$2,393
23	**Subtotal December Estimated**		1,550	1.750	$27,125	1.904	$29,518	$2,393
24								
25	**Period Total**							
26	Economy	OS	270,600	2.704	$7,318,225	3.035	$8,213,526	$895,301
27	**Subtotal Period Total**		270,600	2.704	$7,318,225	3.035	$8,213,526	$895,301
28								

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
Line No.	Capacity Costs	a-Jan - 2020	a-Feb - 2020	a-Mar - 2020	a-Apr - 2020	a-May - 2020	a-Jun - 2020	Jul - 2020	Aug - 2020	Sep - 2020	Oct - 2020	Nov - 2020	Dec - 2020	Total
1	Base													
2	Payments to Non-cogenerators	$2,083,820	$2,083,820	$2,083,820	$2,083,820	$2,412,200	$2,145,800	$2,412,200	$2,412,200	$2,412,200	$2,193,280	$2,193,280	$2,193,280	$26,709,720
3	Payments to Co-generators	$167,174	$119,175	$119,175	$119,175	$119,175	$119,175	$119,175	$119,175	$119,175	$119,175	$119,175	$119,175	$1,478,099
4	Cedar Bay Transaction - Regulatory Asset - Amortization and Return	$9,409,836	$9,378,844	$9,347,853	$9,316,861	$9,285,870	$9,254,879	$9,212,873	$9,182,087	$9,151,301	$9,120,516	$9,089,730	$9,058,945	$110,809,595
5	Cedar Bay Transaction - Regulatory Liability - Amortization and Return	($85,020)	($84,614)	($84,208)	($83,802)	($83,396)	($82,990)	($82,440)	($82,037)	($81,634)	($81,230)	($80,827)	($80,424)	($992,622)
6	Indiantown Transaction - Regulatory Asset - Amortization and Return	$6,173,883	$6,146,004	$6,118,125	$6,090,246	$6,062,368	$6,034,489	$5,994,480	$5,966,786	$5,939,093	$5,911,399	$5,883,706	$5,856,012	$72,176,590
7	SJRPP Revenue Requirements	$863,715	$852,045	$840,376	$828,706	$817,037	$805,367	$792,496	$780,904	$769,312	$757,720	$746,128	$734,536	$9,588,342
8	Incremental Plant Security Costs O&M	$2,520,078	$1,940,794	$2,385,822	$2,117,404	$2,050,331	$2,176,905	$2,788,734	$2,682,087	$2,775,299	$3,056,741	$2,664,141	$2,005,996	$29,164,333
9	Incremental Plant Security Costs Capital	$325,279	$327,832	$329,753	$332,628	$336,952	$340,309	$344,985	$351,013	$355,185	$360,617	$363,563	$385,647	$4,153,762
10	Incremental Nuclear NRC Compliance Costs O&M	$70,186	$67,009	$82,443	$93,471	$68,310	$34,558	$200,029	$198,987	$199,508	$199,508	$198,987	$201,025	$1,614,023
11	Incremental Nuclear NRC Compliance Costs Capital	$1,072,250	$1,071,956	$1,078,562	$1,081,599	$1,080,512	$1,080,755	$1,076,157	$1,078,591	$1,080,893	$1,084,123	$1,090,059	$1,099,469	$12,974,927
12	Transmission of Electricity by Others	$88,540	$77,707	-	-	$661	($548)	$23,111	-	$21,825	$29,078	$29,115	$23,730	$293,218
13	Transmission Revenues from Capacity Sales	($1,111,540)	($1,242,433)	($643,816)	($666,331)	($574,685)	($278,044)	($462,210)	($476,160)	($436,500)	($436,170)	($582,300)	($1,068,650)	($7,978,840)
14	Total Base	$21,578,200	$20,738,139	$21,657,906	$21,313,779	$21,575,334	$21,630,655	$22,419,589	$22,213,634	$22,305,659	$22,314,756	$21,714,757	$20,528,740	$259,991,148
15														
16	Intermediate													
17	Incremental Plant Security Costs O&M	$260,708	$417,161	$297,760	$374,231	$614,490	$562,818	$432,833	$98,272	$122,482	$169,690	$218,272	$136,969	$3,705,687
18	Incremental Plant Security Costs Capital	$45,631	$45,530	$45,429	$45,328	$45,227	$45,126	$45,911	$46,892	$48,369	$51,510	$53,068	$53,662	$571,683
19	Total Intermediate	$306,340	$462,691	$343,189	$419,559	$659,717	$607,944	$478,744	$145,165	$170,851	$221,200	$271,340	$190,631	$4,277,371
20														
21	Peaking													
22	Incremental Plant Security Costs O&M	$41,346	$21,654	$27,891	$26,212	$28,712	$39,282	$55,584	$34,988	$37,433	$36,833	$35,612	$69,592	$455,139
23	Incremental Plant Security Costs Capital	$6,432	$6,413	$6,393	$6,373	$6,354	$6,334	$6,292	$6,273	$6,254	$6,234	$6,215	$6,195	$75,763
24	Total Peaking	$47,778	$28,066	$34,284	$32,586	$35,066	$45,616	$61,876	$41,261	$43,687	$43,067	$41,826	$75,788	$530,902
25														
26	Solar													
27	Incremental Plant Security Costs O&M	-	-	-	-	$130	-	$50,000	-	-	-	$113,357	-	$163,487
28	Incremental Plant Security Costs Capital	$403	$785	$1,131	$1,397	$1,614	$1,665	$1,703	$3,671	$6,069	$6,928	$7,341	$7,309	$40,017
29	Total Solar	$403	$785	$1,131	$1,397	$1,744	$1,665	$51,703	$3,671	$6,069	$6,928	$120,698	$7,309	$203,504
30														
31	General													
32	Incremental Plant Security Costs Capital	$2,598	$2,582	$2,565	$2,549	$2,533	$2,517	$2,500	$2,484	$2,468	$2,452	$2,329	$1,042	$28,619
33	Total General	$2,598	$2,582	$2,565	$2,549	$2,533	$2,517	$2,500	$2,484	$2,468	$2,452	$2,329	$1,042	$28,619
34														
35	Total	$21,935,319	$21,232,263	$22,039,075	$21,769,870	$22,274,395	$22,288,398	$23,014,413	$22,406,215	$22,528,733	$22,588,404	$22,150,950	$20,803,510	$265,031,544
36														
37	Totals may not add due to rounding													

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20200001-EI EXHIBIT: 13
PARTY: FLORIDA POWER & LIGHT COMPANY – DIRECT
DESCRIPTION: R.B.Deaton RBD-4

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
Line No.	Line	a-Jan - 2020	a-Feb - 2020	a-Mar - 2020	a-Apr - 2020	a-May - 2020	a-Jun - 2020	Jul - 2020	Aug - 2020	Sep - 2020	Oct - 2020	Nov - 2020	Dec - 2020	Total
1	Total Capacity Costs (Page 1, Line 35)	$21,935,319	$21,232,263	$22,039,075	$21,769,870	$22,274,395	$22,288,398	$23,014,413	$22,406,215	$22,528,733	$22,588,404	$22,150,950	$20,803,510	$265,031,544
2														
3	Total Base Capacity Costs	$21,578,200	$20,738,139	$21,657,906	$21,313,779	$21,575,334	$21,630,655	$22,419,589	$22,213,634	$22,305,659	$22,314,756	$21,714,757	$20,528,740	$259,991,148
4	Base Jurisdictional Factor (1)	95.79223%	95.79223%	95.79223%	95.79223%	95.79223%	95.79223%	95.79223%	95.79223%	95.79223%	95.79223%	95.79223%	95.79223%	95.79223%
5	Total Base Jurisdictional Capacity Costs	$20,670,238	$19,865,525	$20,746,590	$20,416,943	$20,667,493	$20,720,486	$21,476,224	$21,278,935	$21,367,087	$21,375,802	$20,801,050	$19,664,937	$249,051,311
6														
7	Total Intermediate Capacity Costs	$306,340	$462,691	$343,189	$419,559	$659,717	$607,944	$478,744	$145,165	$170,851	$221,200	$271,340	$190,631	$4,277,371
8	Intermediate Jurisdictional Factor (1)	94.15685%	94.15685%	94.15685%	94.15685%	94.15685%	94.15685%	94.15685%	94.15685%	94.15685%	94.15685%	94.15685%	94.15685%	94.15685%
9	Total Intermediate Jurisdictional Capacity Costs	$288,440	$435,656	$323,136	$395,043	$621,169	$572,421	$450,770	$136,683	$160,868	$208,275	$255,485	$179,492	$4,027,438
10														
11	Total Peaking Capacity Costs	$47,778	$28,066	$34,284	$32,586	$35,066	$45,616	$61,876	$41,261	$43,687	$43,067	$41,826	$75,788	$530,902
12	Peaking Jurisdictional Factor (1)	95.04549%	95.04549%	95.04549%	95.04549%	95.04549%	95.04549%	95.04549%	95.04549%	95.04549%	95.04549%	95.04549%	95.04549%	95.04549%
13	Total Peaking Jurisdictional Capacity Costs	$45,411	$26,676	$32,586	$30,971	$33,329	$43,356	$58,811	$39,216	$41,522	$40,934	$39,754	$72,033	$504,599
14														
15	Total Solar Capacity Costs	$403	$785	$1,131	$1,397	$1,744	$1,665	$51,703	$3,671	$6,069	$6,928	$120,698	$7,309	$203,504
16	Solar Jurisdictional Factor (1)	95.79223%	95.79223%	95.79223%	95.79223%	95.79223%	95.79223%	95.79223%	95.79223%	95.79223%	95.79223%	95.79223%	95.79223%	95.79223%
17	Total Solar Jurisdcitional Capacity Costs	$386	$752	$1,084	$1,338	$1,671	$1,595	$49,528	$3,516	$5,814	$6,637	$115,619	$7,002	$194,941
18														
19	Total Transmission Capacity Costs	-	-	-	-	-	-	-	-	-	-	-	-	-
20	Transmission Jurisdictional Factor (1)	89.93869%	89.93869%	89.93869%	89.93869%	89.93869%	89.93869%	89.93869%	89.93869%	89.93869%	89.93869%	89.93869%	89.93869%	89.93869%
21	Total Transmission Jurisdictional Capacity Costs													
22														
23	Total General Capacity Costs	$2,598	$2,582	$2,565	$2,549	$2,533	$2,517	$2,500	$2,484	$2,468	$2,452	$2,329	$1,042	$28,619
24	General Jurisdictional Factor (1)	96.91235%	96.91235%	96.91235%	96.91235%	96.91235%	96.91235%	96.91235%	96.91235%	96.91235%	96.91235%	96.91235%	96.91235%	96.91235%
25	Total General Jurisdictional Capacity Costs	$2,518	$2,502	$2,486	$2,471	$2,455	$2,439	$2,423	$2,408	$2,392	$2,376	$2,257	$1,010	$27,736
26														
27	Net Jurisdictional Capacity Costs	21,006,993	20,331,110	21,105,881	20,846,767	21,326,117	21,340,298	22,037,756	21,460,758	21,577,683	21,634,024	21,214,165	19,924,473	253,806,024
28														
29	(1) As approved in Order No. PSC-2019-0484-FOF-EI.													
30														
31	Totals may not add due to rounding													

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
Line No.	Line	a-Jan - 2020	a-Feb - 2020	a-Mar - 2020	a-Apr - 2020	a-May - 2020	a-Jun - 2020	Jul - 2020	Aug - 2020	Sep - 2020	Oct - 2020	Nov - 2020	Dec - 2020	Total
1	Net Jurisdictional CCR Costs (Page 2, Line 27)	$21,006,993	$20,331,110	$21,105,881	$20,846,767	$21,326,117	$21,340,298	$22,037,756	$21,460,758	$21,577,683	$21,634,024	$21,214,165	$19,924,473	$253,806,024
2														
3	CCR Revenues (Net of Revenue Taxes)	$17,225,349	$16,294,404	$17,058,910	$19,576,540	$19,584,553	$21,402,820	$23,143,455	$23,927,619	$23,090,258	$21,099,088	$18,829,656	$17,020,048	$238,252,700
4	Prior Period True-up Provision	$1,347,028	$1,347,028	$1,347,028	$1,347,028	$1,347,028	$1,347,028	$1,347,028	$1,347,028	$1,347,028	$1,347,028	$1,347,028	$1,347,028	$16,164,334
5	2017 SoBRA Refund	$554,832	$554,832	$554,832	$554,832	$554,832	$554,832	$554,832	$554,832	$554,832	$554,832	$554,832	$554,832	$6,657,982
6	CCR Revenues Applicable to Current Period (Net of Revenue Taxes)	$19,127,209	$18,196,263	$18,960,770	$21,478,400	$21,486,413	$23,304,679	$25,045,315	$25,829,479	$24,992,117	$23,000,948	$20,731,516	$18,921,908	$261,075,016
7														
8	True-up Provision - Over/(Under) Recovery (Line 6 - Line 1)	($1,879,784)	($2,134,847)	($2,145,112)	$631,633	$160,296	$1,964,382	$3,007,559	$4,368,721	$3,414,435	$1,366,924	($482,649)	($1,002,566)	$7,268,993
9	Interest Provision	$35,090	$29,598	$28,568	$14,714	$820	$1,102	$1,381	$1,560	$1,759	$1,808	$1,662	$1,398	$119,461
10	True-up & Interest Provision Beginning of Year - Over/(Under) Recovery	$22,822,316	$19,075,768	$15,068,665	$11,050,268	$9,794,760	$8,054,023	$8,117,646	$9,224,727	$11,693,148	$13,207,482	$12,674,355	$10,291,481	$22,822,316
11	Deferred True-up - Over/(Under) Recovery	$5,141,967	$5,141,967	$5,141,967	$5,141,967	$5,141,967	$5,141,967	$5,141,967	$5,141,967	$5,141,967	$5,141,967	$5,141,967	$5,141,967	$5,141,967
12	2017 SoBRA Refund	($554,832)	($554,832)	($554,832)	($554,832)	($554,832)	($554,832)	($554,832)	($554,832)	($554,832)	($554,832)	($554,832)	($554,832)	($6,657,982)
13	Prior Period True-up Provision - Collected/(Refunded)	($1,347,028)	($1,347,028)	($1,347,028)	($1,347,028)	($1,347,028)	($1,347,028)	($1,347,028)	($1,347,028)	($1,347,028)	($1,347,028)	($1,347,028)	($1,347,028)	($16,164,334)
14	End of Period True-up - Over/(Under) Recovery (Lines 8 through 13)	$24,217,729	$20,210,627	$16,192,229	$14,936,722	$13,195,984	$13,259,613	$14,366,694	$16,835,115	$18,349,449	$17,816,322	$15,433,476	$12,530,421	$12,530,421
15														
16	Totals may not add due to rounding													

(1)	(2)	(3)	(4)	(5)	(6)
Line No.	Line	Actual/Estimated	Original Projection	$ Difference	% Difference
1	Payments to Non-cogenerators	$26,709,720	$26,754,120	($44,400)	(0.2%)
2	Payments to Co-generators	$1,478,099	$1,430,100	$47,999	3.4%
3	Cedar Bay Transaction - Reg Asset - Amort & Return	$110,809,595	$111,056,656	($247,061)	(0.2%)
4	Cedar Bay Transaction - Reg Liability - Amort & Return	($992,622)	($995,858)	$3,236	(0.3%)
5	Indiantown Transaction - Regulatory Asset - Amortization and Return	$72,176,590	$72,448,966	($272,376)	(0.4%)
6	Incremental Plant Security Costs-Order No. PSC-02-1761 (O&M)	$33,488,647	$32,402,339	$1,086,308	3.4%
7	Incremental Plant Security Costs-Order No. PSC-02-1761 (Capital)	$4,869,845	$5,815,568	($945,723)	(16.3%)
8	Incremental Nuclear NRC Compliance Costs O&M	$1,614,023	$1,010,084	$603,939	59.8%
9	Incremental Nuclear NRC Compliance Costs Capital	$12,974,927	$14,053,337	($1,078,410)	(7.7%)
10	Transmission of Electricity by Others	$293,218	$398,356	($105,138)	(26.4%)
11	Transmission Revenues from Capacity Sales	($7,978,840)	($6,079,534)	($1,899,306)	31.2%
12	SJRPP Transaction Revenue Requirements	$9,588,342	$9,614,923	($26,582)	(0.3%)
13	Total Capacity Costs	$265,031,544	$267,909,057	($2,877,513)	(1.1%)
14					
15					
16	Totals may not add due to rounding				

(1)	(2)	(3)	(4)	(5)	(6)
Line No.	Line	Actual/Estimated	Original Projection	$ Difference	% Difference
1	Total Capacity Costs	$265,031,544	$267,909,057	($2,877,513)	(1.1%)
2					
3	Total Base Capacity Costs	$259,991,148	$264,264,148	($4,273,000)	(1.6%)
4	Base Jurisdictional Factor	95.79%	95.79223%		
5	Total Base Jurisdictionalized Capacity Costs	$249,051,311	$253,144,513	($4,093,202)	(1.6%)
6					
7	Total Intermediate Capacity Costs	$4,277,371	$2,235,993	$2,041,378	91.3%
8	Intermediate Jurisdictional Factor	94.16%	94.15685%		
9	Total Intermediate Jurisdictionalized Capacity Costs	$4,027,438	$2,103,699	$1,923,739	91.4%
10					
11	Total Peaking Capacity Costs	$530,902	$579,981	($49,079)	(8.5%)
12	Peaking Jurisdictional Factor	95.05%	95.04549%		
13	Total Peaking Jurisidictionalized Capacity Costs	$504,599	$552,903	($48,304)	(8.7%)
14					
15	Total Solar Capacity Costs	$203,504	$665,422	($461,918)	(69.4%)
16	Solar Jurisdictional Factor	95.79%	95.79223%		
17	Total Solar Jurisdictionalized Capacity Costs	$194,941	$637,423	($442,482)	(69.4%)
18					
19	Total General Capacity Costs	$28,619	$163,514	($134,894)	(82.5%)
20	General Jurisdictional Factor	96.91%	96.91235%		
21	Total General Jurisdictionalized Capacity Costs	$27,736	$158,465	($130,729)	(82.5%)
22					
23	Transmission Jurisdictional Factor	89.94%	89.93869%		
24	Jurisdictional Capacity Charges	$253,806,024	$256,597,002	($2,790,978)	(1.1%)
25					
26					
27	CCR Revenues	$238,252,700	$233,774,686	$4,478,014	1.9%
28	Prior Period True-up Provision	$16,164,334	$16,164,334	$0	0.0%
29	2017 SoBRA Refund	$6,657,982	$6,657,982	$0	N/A
30	CCR Revenues Applicable to Current Period (Net of Revenue Taxes)	$261,075,016	$256,597,002	$4,478,014	1.9%
31					
32	True-up Provision for Month - Over/(Under) Recovery	$7,268,993	$0	$7,268,993	N/A
33	Interest Provision for the Month	$119,461	$0	$119,461	N/A
34	True-Up & Interest Provision - Beginning of Year	$22,822,316	$22,822,316	$0	N/A
35	Deferred True-up - Over/(Under) Recovery	$5,141,967	$0	$5,141,967	N/A
36	2017 SoBRA Refund	($6,657,982)	($6,657,982)	$0	N/A
37	Prior Period True-up Provision - Collected/(Refunded) this Month	($16,164,334)	($16,164,334)	($0)	(0.0%)
38	End of Period True-up - Over/(Under) Recovery	$12,530,421	$0	$12,530,421	N/A
39					
40	Totals may not add due to rounding				

Line No.	Strata	Line	Beginning of Period Amount	a-Jan - 2020	a-Feb - 2020	a-Mar - 2020	a-Apr - 2020	a-May - 2020	a-Jun - 2020	Jul - 2020	Aug - 2020	Sep - 2020	Oct - 2020	Nov - 2020	Dec - 2020	Twelve Month Total
1	**Base**	**INVESTMENTS**														
2		Expenditures/Additions		$370,983	$592,059	$183,653	$875,451	$615,449	$587,979	$414,368	$531,818	$944,081	$911,991	$980,118	($20,152,839)	($13,144,889)
3		Clearings to Plant		-	-	-	-	-	-	$309,384	-	-	-	-	$20,803,337	$21,112,721
4		Retirements		-	-	-	-	-	-	-	-	-	-	-	($313,513)	($313,513)
5		Other		($3,272)	($5,360)	($1,240)	($7,938)	($3,771)	($5,896)	-	-	-	-	-	-	($27,478)
6																
7		Plant-In-Service/Depreciation Base	$22,916,916	$22,916,916	$22,916,916	$22,916,916	$22,916,916	$22,916,916	$22,916,916	$23,226,300	$23,226,300	$23,226,300	$23,226,300	$23,226,300	$44,029,637	
8		Less: Accumulated Depreciation	$2,866,622	$2,966,356	$3,064,003	$3,165,770	$3,260,838	$3,360,074	$3,457,185	$3,562,770	$3,670,933	$3,779,096	$3,887,260	$3,992,810	$3,801,246	
9		CWIP - Non Interest Bearing	$13,144,889	$13,515,872	$14,107,931	$14,291,584	$15,167,035	$15,782,484	$16,370,464	$16,784,831	$17,316,649	$18,260,730	$19,172,721	$20,152,839	$0	
10																
11		Net Investment (Lines 7 - 8 + 9)	$33,195,184	$33,466,431	$33,960,844	$34,042,731	$34,823,113	$35,339,326	$35,830,195	$36,448,362	$36,872,016	$37,707,934	$38,511,762	$39,386,329	$40,228,391	
12																
13		Average Net Investment		$33,330,808	$33,713,638	$34,001,787	$34,432,922	$35,081,219	$35,584,760	$36,139,278	$36,660,189	$37,289,975	$38,109,848	$38,949,045	$39,807,360	
14																
15		Return on Average Net Investment														
16		a. Equity Component grossed up for taxes (1)		$184,755	$186,877	$188,474	$190,864	$194,457	$197,248	$198,627	$201,490	$204,952	$209,458	$214,070	$218,788	$2,390,059
17		b. Debt Component (Line 13 x debt rate x 1/12) (2)		$37,517	$37,948	$38,272	$38,758	$39,487	$40,054	$40,772	$41,360	$42,071	$42,996	$43,942	$44,911	$488,088
18																
19		Investment Expenses														
20		a. Depreciation		$103,007	$103,007	$103,007	$103,007	$103,007	$103,007	$105,585	$108,163	$108,163	$108,163	$105,551	$121,949	$1,275,615
21		b. Amortization														
22		c. Other														
23																
24		Total System Recoverable Expenses (Lines 16 + 17 + 20)		$325,279	$327,832	$329,753	$332,628	$336,952	$340,309	$344,985	$351,013	$355,185	$360,617	$363,563	$385,647	$4,153,762
25																
26																
27																
28																

29 [1] The Gross-up factor for taxes is 0.75478, which reflects the Federal Income Tax Rate of 21%. The monthly Equity Component for the Jan. – Jun. 2020 period is 5.0206%, based on May 2019 ROR Surveillance Report

30 and reflects a 10.55% return on equity, and the monthly Equity Component for the Jul. – Dec. 2020 period is 4.9781% based on the May 2020 ROR Surveillance Report and reflects a 10.55% return on equity.

31 [2] The Debt Component for the Jan. – Jun. 2020 period is 1.3507% is based on the May 2019 Earnings Surveillance Report and the Debt Component for the Jul. – Dec. 2020 period is 1.3538% based on the May 2020 Earnings Surveillance Report.

32

33 Totals may not add due to rounding

Line No.	Strata	Line	Beginning of Period Amount	a-Jan - 2020	a-Feb - 2020	a-Mar - 2020	a-Apr - 2020	a-May - 2020	a-Jun - 2020	Jul - 2020	Aug - 2020	Sep - 2020	Oct - 2020	Nov - 2020	Dec - 2020	Twelve Month Total
1	**Intermediate**	**INVESTMENTS**														
2		Expenditures/Additions		-	-	-	-	-	-	-	-	-	$503,750	-	($503,750)	-
3		Clearings to Plant		-	-	-	-	-	-	$230,113	-	$335,510	-	-	$503,750	$1,069,373
4		Retirements		-	-	-	-	-	-	-	-	-	-	-	-	-
5		Other		-	-	-	-	-	-	-	-	-	-	-	-	-
6																
7		Plant-In-Service/Depreciation Base	$5,340,984	$5,340,984	$5,340,984	$5,340,984	$5,340,984	$5,340,984	$5,340,984	$5,571,098	$5,571,098	$5,906,607	$5,906,607	$5,906,607	$6,410,357	
8		Less: Accumulated Depreciation	$764,038	$779,198	$794,358	$809,518	$824,678	$839,838	$854,997	$870,481	$886,287	$902,564	$919,312	$936,061	$953,517	
9		CWIP - Non Interest Bearing											$503,750	$503,750		
10																
11		Net Investment (Lines 7 - 8 + 9)	$4,576,946	$4,561,786	$4,546,626	$4,531,467	$4,516,307	$4,501,147	$4,485,987	$4,700,617	$4,684,811	$5,004,043	$5,491,045	$5,474,296	$5,456,841	
12																
13		Average Net Investment		$4,569,366	$4,554,206	$4,539,047	$4,523,887	$4,508,727	$4,493,567	$4,593,302	$4,692,714	$4,844,427	$5,247,544	$5,482,671	$5,465,568	
14																
15		Return on Average Net Investment														
16		a. Equity Component grossed up for taxes		$25,328	$25,244	$25,160	$25,076	$24,992	$24,908	$25,246	$25,792	$26,626	$28,841	$30,134	$30,040	$317,387
17		b. Debt Component (Line 13 x debt rate x 1/12)		$5,143	$5,126	$5,109	$5,092	$5,075	$5,058	$5,182	$5,294	$5,465	$5,920	$6,186	$6,166	$64,818
18																
19		Investment Expenses														
20		a. Depreciation		$15,160	$15,160	$15,160	$15,160	$15,160	$15,160	$15,483	$15,806	$16,277	$16,748	$16,748	$17,456	$189,479
21		b. Amortization														
22		c. Other														
23																
24		Total System Recoverable Expenses (Lines 16 + 17 + 20)		$45,631	$45,530	$45,429	$45,328	$45,227	$45,126	$45,911	$46,892	$48,369	$51,510	$53,068	$53,662	$571,683
25																
26																
27																
28																

29 (1) The Gross-up factor for taxes is 0.75478, which reflects the Federal Income Tax Rate of 21%. The monthly Equity Component for the Jan. – Jun. 2020 period is 5.0206%, based on May 2019 ROR Surveillance Report

30 and reflects a 10.55% return on equity, and the monthly Equity Component for the Jul. – Dec. 2020 period is 4.9781% based on the May 2020 ROR Surveillance Report and reflects a 10.55% return on equity.

31 (2) The Debt Component for the Jan. – Jun. 2020 period is 1.3507% is based on the May 2019 Earnings Surveillance Report and the Debt Component for the Jul. – Dec. 2020 period is 1.3538% based on the May 2020 Earnings Surveillance Report.

32

33 Totals may not add due to rounding

Line No.	Strata	Line	Beginning of Period Amount	a-Jan - 2020	a-Feb - 2020	a-Mar - 2020	a-Apr - 2020	a-May - 2020	a-Jun - 2020	Jul - 2020	Aug - 2020	Sep - 2020	Oct - 2020	Nov - 2020	Dec - 2020	Twelve Month Total
1	**Peaking**	**INVESTMENTS**														
2		Expenditures/Additions		-	-	-	-	-	-	-	-	-	-	-	-	-
3		Clearings to Plant		-	-	-	-	-	-	-	-	-	-	-	-	-
4		Retirements		-	-	-	-	-	-	-	-	-	-	-	-	-
5		Other		-	-	-	-	-	-	-	-	-	-	-	-	-
6																
7		Plant-In-Service/Depreciation Base	$672,783	$672,783	$672,783	$672,783	$672,783	$672,783	$672,783	$672,783	$672,783	$672,783	$672,783	$672,783	$672,783	
8		Less: Accumulated Depreciation	$146,041	$148,970	$151,899	$154,828	$157,758	$160,687	$163,616	$166,545	$169,474	$172,404	$175,333	$178,262	$181,191	
9		CWIP - Non Interest Bearing														
10																
11		Net Investment (Lines 7 - 8 + 9)	$526,742	$523,813	$520,884	$517,955	$515,025	$512,096	$509,167	$506,238	$503,309	$500,379	$497,450	$494,521	$491,592	
12																
13		Average Net Investment		$525,278	$522,348	$519,419	$516,490	$513,561	$510,632	$507,702	$504,773	$501,844	$498,915	$495,986	$493,057	
14																
15		Return on Average Net Investment														
16		a. Equity Component grossed up for taxes		$2,912	$2,895	$2,879	$2,863	$2,847	$2,830	$2,790	$2,774	$2,758	$2,742	$2,726	$2,710	$33,727
17		b. Debt Component (Line 13 x debt rate x 1/12)		$591	$588	$585	$581	$578	$575	$573	$569	$566	$563	$560	$556	$6,885
18																
19		Investment Expenses														
20		a. Depreciation		$2,929	$2,929	$2,929	$2,929	$2,929	$2,929	$2,929	$2,929	$2,929	$2,929	$2,929	$2,929	$35,150
21		b. Amortization														
22		c. Other														
23																
24		Total System Recoverable Expenses (Lines 16 + 17 + 20)		$6,432	$6,413	$6,393	$6,373	$6,354	$6,334	$6,292	$6,273	$6,254	$6,234	$6,215	$6,195	$75,763
25																
26																
27																
28																

29 [b] The Gross-up factor for taxes is 0.75478, which reflects the Federal Income Tax Rate of 21%. The monthly Equity Component for the Jan. – Jun. 2020 period is 5.0206%, based on May 2019 ROR Surveillance Report

30 and reflects a 10.55% return on equity, and the monthly Equity Component for the Jul. – Dec. 2020 period is 4.9781% based on the May 2020 ROR Surveillance Report and reflects a 10.55% return on equity.

31 [c] The Debt Component for the Jan. – Jun. 2020 period is 1.3507% is based on the May 2019 Earnings Surveillance Report and the Debt Component for the Jul. – Dec. 2020 period is 1.3538% based on the May 2020 Earnings Surveillance Report.

32

33 Totals may not add due to rounding

Line No.	Strata	Line	Beginning of Period Amount	a-Jan - 2020	a-Feb - 2020	a-Mar - 2020	a-Apr - 2020	a-May - 2020	a-Jun - 2020	Jul - 2020	Aug - 2020	Sep - 2020	Oct - 2020	Nov - 2020	Dec - 2020	Twelve Month Total
1	**General**	**INVESTMENTS**														
2		Expenditures/Additions		-	-	-	-	-	-	-	-	-	-	-	-	-
3		Clearings to Plant		-	-	-	-	-	-	-	-	-	-	-	-	-
4		Retirements		-	-	-	-	-	-	-	-	-	-	-	($12,959)	($12,959)
5		Other		-	-	-	-	-	-	-	-	-	-	-	-	-
6																
7		Plant-In-Service/Depreciation Base	$145,284	$145,284	$145,284	$145,284	$145,284	$145,284	$145,284	$145,284	$145,284	$145,284	$145,284	$145,284	$145,284	
8		Less: Accumulated Depreciation	$117,632	$120,053	$122,475	$124,896	$127,317	$129,739	$132,160	$134,582	$137,003	$139,424	$141,846	$144,159	$132,195	
9		CWIP - Non Interest Bearing	-	-	-	-	-	-	-	-	-	-	-	-	-	
10																
11		Net Investment (Lines 7 - 8 + 9)	$27,652	$25,231	$22,809	$20,388	$17,966	$15,545	$13,124	$10,702	$8,281	$5,859	$3,438	$1,125	$13,089	
12																
13		Average Net Investment		$26,441	$24,020	$21,599	$19,177	$16,756	$14,334	$11,913	$9,492	$7,070	$4,649	$2,281	$7,107	
14																
15		Return on Average Net Investment														
16		a. Equity Component grossed up for taxes		$147	$133	$120	$106	$93	$79	$65	$52	$39	$26	$13	$39	$912
17		b. Debt Component (Line 13 x debt rate x 1/12)		$30	$27	$24	$22	$19	$16	$13	$11	$8	$5	$3	$8	$186
18																
19		Investment Expenses														
20		a. Depreciation		$2,421	$2,421	$2,421	$2,421	$2,421	$2,421	$2,421	$2,421	$2,421	$2,421	$2,313	$995	$27,522
21		b. Amortization														
22		c. Other														
23																
24		Total System Recoverable Expenses (Lines 16 + 17 + 20)		$2,598	$2,582	$2,565	$2,549	$2,533	$2,517	$2,500	$2,484	$2,468	$2,452	$2,329	$1,042	$28,619
25																
26																
27																
28																

29 [(1)] The Gross-up factor for taxes is 0.75478, which reflects the Federal Income Tax Rate of 21%. The monthly Equity Component for the Jan. – Jun. 2020 period is 5.0206%, based on May 2019 ROR Surveillance Report

30 and reflects a 10.55% return on equity, and the monthly Equity Component for the Jul. – Dec. 2020 period is 4.9781% based on the May 2020 ROR Surveillance Report and reflects a 10.55% return on equity.

31 [(2)] The Debt Component for the Jan. – Jun. 2020 period is 1.3507% is based on the May 2019 Earnings Surveillance Report and the Debt Component for the Jul. – Dec. 2020 period is 1.3538% based on the May 2020 Earnings Surveillance Report.

32

33 Totals may not add due to rounding

Line No.	Strata	Line	Beginning of Period Amount	a-Jan - 2020	a-Feb - 2020	a-Mar - 2020	a-Apr - 2020	a-May - 2020	a-Jun - 2020	Jul - 2020	Aug - 2020	Sep - 2020	Oct - 2020	Nov - 2020	Dec - 2020	Twelve Month Total
1	**Solar**	**INVESTMENTS**														
2		Expenditures/Additions		$26,047	$88,561	$15,305	$64,435	$608	$14,769	-	($257,099)	-	-	-	-	($47,374)
3		Clearings to Plant		-	-	-	-	-	-	-	$304,961	$47,862	$47,862	-	-	$400,685
4		Retirements		-	-	-	-	-	-	-	-	-	-	-	-	-
5		Other		-	-	-	-	-	-	-	-	-	-	-	-	-
6																
7		Plant-In-Service/Depreciation Base	-	-	-	-	-	-	-	-	$304,961	$352,823	$400,685	$400,685	$400,685	
8		Less: Accumulated Depreciation	-	-	-	-	-	-	-	-	$1,815	$5,731	$10,216	$14,986	$19,756	
9		CWIP - Non Interest Bearing	$47,374	$73,421	$161,981	$177,287	$241,722	$242,330	$257,099	$257,099	-	-	-	-	-	
10																
11		Net Investment (Lines 7 - 8 + 9)	$47,374	$73,421	$161,981	$177,287	$241,722	$242,330	$257,099	$257,099	$303,145	$347,092	$390,469	$385,699	$380,929	
12																
13		Average Net Investment		$60,397	$117,701	$169,634	$209,504	$242,026	$249,714	$257,099	$280,122	$325,119	$368,780	$388,084	$383,314	
14																
15		Return on Average Net Investment														
16		a. Equity Component grossed up for taxes		$335	$652	$940	$1,161	$1,342	$1,384	$1,413	$1,540	$1,787	$2,027	$2,133	$2,107	$16,821
17		b. Debt Component (Line 13 x debt rate x 1/12)		$68	$132	$191	$236	$272	$281	$290	$316	$367	$416	$438	$432	$3,440
18																
19		Investment Expenses														
20		a. Depreciation		$0	$0	$0	$0	$0	$0	$0	$1,815	$3,915	$4,485	$4,770	$4,770	$19,756
21		b. Amortization		-	-	-	-	-	-	-	-	-	-	-	-	-
22		c. Other		-	-	-	-	-	-	-	-	-	-	-	-	-
23																
24		Total System Recoverable Expenses (Lines 16 + 17 + 20)		$403	$785	$1,131	$1,397	$1,614	$1,665	$1,703	$3,671	$6,069	$6,928	$7,341	$7,309	$40,017

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29 [1] The Gross-up factor for taxes is 0.75478, which reflects the Federal Income Tax Rate of 21%. The monthly Equity Component for the Jan. – Jun. 2020 period is 5.0206%, based on May 2019 ROR Surveillance Report
30 and reflects a 10.55% return on equity, and the monthly Equity Component for the Jul. – Dec. 2020 period is 4.9781% based on the May 2020 ROR Surveillance Report and reflects a 10.55% return on equity.
31 [2] The Debt Component for the Jan. – Jun. 2020 period is 1.3507% is based on the May 2019 Earnings Surveillance Report and the Debt Component for the Jul. – Dec. 2020 period is 1.3538% based on the May 2020 Earnings Surveillance Report.
32
33 Totals may not add due to rounding

Line No.	Line	Beginning of Period Amount	a-Jan - 2020	a-Feb - 2020	a-Mar - 2020	a-Apr - 2020	a-May - 2020	a-Jun - 2020	Jul - 2020	Aug - 2020	Sep - 2020	Oct - 2020	Nov - 2020	Dec - 2020	Twelve Month Total
1	**INVESTMENTS**														
2	Expenditures/Additions		$475,685	$606,045	($163,992)	($1,369,389)	$459,328	$284,406	$454,880	$1,109,459	$414,978	$1,389,552	$1,041,001	($4,409,870)	$292,082
3	Clearings to Plant		($336,616)	$109,966	$1,304,281	($2,997,445)	$67,252	$17,933	-	-	-	-	-	$4,653,776	$2,819,147
4	Retirements		-	-	-	($5,883,548)	-	-	-	-	-	-	-	-	($5,883,548)
5	Other		($7,130)	($13,379)	($19,475)	($258,268)	($15,562)	($8,969)	-	-	-	-	-	-	($322,782)
6															
7	Plant-In-Service/Depreciation Base	$110,334,934	$109,998,318	$110,108,284	$111,412,565	$108,415,120	$108,482,372	$108,500,305	$108,500,305	$108,500,305	$108,500,305	$108,500,305	$108,500,305	$113,154,081	
8	Less: Accumulated Depreciation	$13,619,444	$14,034,100	$14,442,105	$14,847,141	$9,125,907	$9,524,897	$9,930,642	$10,345,394	$10,760,145	$11,174,896	$11,589,647	$12,005,034	$12,428,353	
9	CWIP - Non Interest Bearing	$962,770	$1,438,455	$2,044,500	$1,880,507	$511,118	$970,446	$1,254,852	$1,709,731	$2,819,190	$3,234,168	$4,623,720	$5,664,721	$1,254,852	
10															
11	Net Investment (Lines 7 - 8 + 9)	$97,678,260	$97,402,673	$97,710,678	$98,445,930	$99,800,331	$99,927,921	$99,824,514	$99,864,643	$100,559,350	$100,559,577	$101,534,378	$102,159,992	$101,980,580	
12															
13	Average Net Investment		$97,540,466	$97,556,676	$98,078,304	$99,123,131	$99,864,126	$99,876,218	$99,844,578	$100,211,997	$100,559,464	$101,046,978	$101,847,185	$102,070,286	
14															
15	Return on Average Net Investment														
16	a. Equity Component grossed up for taxes [1]		$540,673	$540,762	$543,654	$549,445	$553,553	$553,620	$548,762	$550,781	$552,691	$555,370	$559,768	$560,994	$6,610,073
17	b. Debt Component (Line 13 x debt rate x 1/12) [2]		$109,792	$109,810	$110,397	$111,573	$112,407	$112,421	$112,645	$113,059	$113,451	$114,001	$114,904	$115,156	$1,349,615
18															
19	Investment Expenses														
20	a. Depreciation		$421,786	$421,383	$424,511	$420,581	$414,553	$414,714	$414,751	$414,751	$414,751	$414,751	$415,387	$423,318	$5,015,239
21	b. Amortization														
22	c. Other														
23															
24	Total System Recoverable Expenses (Lines 16 + 17 + 20)		$1,072,250	$1,071,956	$1,078,562	$1,081,599	$1,080,512	$1,080,755	$1,076,157	$1,078,591	$1,080,893	$1,084,123	$1,090,059	$1,099,469	$12,974,927
25															
26															
27															
28															

29 [1] The Gross-up factor for taxes is 0.75478, which reflects the Federal Income Tax Rate of 21%. The monthly Equity Component for the Jan. – Jun. 2020 period is 5.0206%, based on May 2019 ROR Surveillance Report

30 and reflects a 10.55% return on equity, and the monthly Equity Component for the Jul. – Dec. 2020 period is 4.9781% based on the May 2020 ROR Surveillance Report and reflects a 10.55% return on equity.

31 [2] The Debt Component for the Jan. – Jun. 2020 period is 1.3507% is based on the May 2019 Earnings Surveillance Report and the Debt Component for the Jul. – Dec. 2020 period is 1.3538% based on the May 2020 Earnings Surveillance Report.

32

33 Totals may not add due to rounding

Line No.	Line	Beginning of Period	a-Jan - 2020	a-Feb - 2020	a-Mar - 2020	a-Apr - 2020	a-May - 2020	a-Jun - 2020	Jul - 2020	Aug - 2020	Sep - 2020	Oct - 2020	Nov - 2020	Dec - 2020	Total
1															
2	Regulatory Asset - Loss of PPA		$278,839,317	$274,191,995	$269,544,673	$264,897,351	$260,250,029	$255,602,707	$250,955,385	$246,308,063	$241,660,741	$237,013,419	$232,366,097	$227,718,775	
3															
4	Regulatory Asset - Loss of PPA Amort		$4,647,322	$4,647,322	$4,647,322	$4,647,322	$4,647,322	$4,647,322	$4,647,322	$4,647,322	$4,647,322	$4,647,322	$4,647,322	$4,647,322	$55,767,864
5															
6	Unamortized Regulatory Asset - Loss of PPA	$278,839,317	$274,191,995	$269,544,673	$264,897,351	$260,250,029	$255,602,707	$250,955,385	$246,308,063	$241,660,741	$237,013,419	$232,366,097	$227,718,775	$223,071,453	
7															
8	Average Unamortized Regulatory Asset - Loss of PPA		$276,515,656	$271,868,334	$267,221,012	$262,573,690	$257,926,368	$253,279,046	$248,631,724	$243,984,402	$239,337,080	$234,689,758	$230,042,436	$225,395,114	
9															
10	Regulatory Asset - Income Tax Gross Up	178,030,026	175,111,501	172,192,976	169,274,451	166,355,926	163,437,401	160,518,876	157,600,351	154,681,826	151,763,301	148,844,776	145,926,251	143,007,726	
11															
12	Regulatory Asset Amortization - Income Tax Gross-Up		2,918,525	2,918,525	2,918,525	2,918,525	2,918,525	2,918,525	2,918,525	2,918,525	2,918,525	2,918,525	2,918,525	2,918,525	35,022,300
13															
14	Unamortized Regulatory Asset - Income Tax Gross Up		172,192,976	169,274,451	166,355,926	163,437,401	160,518,876	157,600,351	154,681,826	151,763,301	148,844,776	145,926,251	143,007,726	140,089,201	
15															
16	Return on Unamortized Regulatory Asset - Loss of PPA only														
17	Equity Component (1)		$1,156,886	$1,137,443	$1,117,999	$1,098,556	$1,079,112	$1,059,669	$1,031,424	$1,012,145	$992,866	$973,587	$954,308	$935,029	$12,549,024
18															
19	Equity Comp. grossed up for taxes (1)(2)		$1,532,743	$1,506,982	$1,481,222	$1,455,461	$1,429,701	$1,403,941	$1,366,519	$1,340,977	$1,315,434	$1,289,892	$1,264,350	$1,238,807	$16,626,029
20															
21	Debt Component (Line 8 * debt rate / 12) (2)		$311,246	$306,015	$300,784	$295,553	$290,322	$285,091	$280,506	$275,263	$270,020	$264,777	$259,534	$254,291	$3,393,402
22															
23	Total Return Requirements (Line 19 + 21)		$1,843,989	$1,812,997	$1,782,006	$1,751,014	$1,720,023	$1,689,032	$1,647,026	$1,616,240	$1,585,454	$1,554,669	$1,523,883	$1,493,098	$20,019,431
24	Total Recoverable Costs (Line 4 + 12 + 23)		$9,409,836	$9,378,844	$9,347,853	$9,316,861	$9,285,870	$9,254,879	$9,212,873	$9,182,087	$9,151,301	$9,120,516	$9,089,730	$9,058,945	$110,809,595
25															
26															
27	(1) The Gross-up factor for taxes is 0.75478, which reflects the Federal Income Tax Rate of 21%. The monthly Equity Component for the Jan. – Jun. 2020 period is 5.0206%, based on May 2019 ROR Surveillance Report														
28	and reflects a 10.55% return on equity, and the monthly Equity Component for the Jul. – Dec. 2020 period is 4.9781% based on the May 2020 ROR Surveillance Report and reflects a 10.55% return on equity.														
29	(2) The Debt Component for the Jan. – Jun. 2020 period is 1.3507% is based on the May 2019 Earnings Surveillance Report and the Debt Component for the Jul. – Dec. 2020 period is 1.3538% based on the May 2020 Earnings Surveillance Report.														
30															
31	Totals may not add due to rounding														

Line No.	Line	Beginning of Period Amount	a-Jan - 2020	a-Feb - 2020	a-Mar - 2020	a-Apr - 2020	a-May - 2020	a-Jun - 2020	Jul - 2020	Aug - 2020	Sep - 2020	Oct - 2020	Nov - 2020	Dec - 2020	Total
1															
2	Regulatory Liability - Book/Tax Timing Difference [3]		($3,652,117)	($3,591,249)	($3,530,381)	($3,469,513)	($3,408,645)	($3,347,777)	($3,286,909)	($3,226,041)	($3,165,173)	($3,104,305)	($3,043,437)	($2,982,569)	
3															
4	Regulatory Liability Amortization		$60,868	$60,868	$60,868	$60,868	$60,868	$60,868	$60,868	$60,868	$60,868	$60,868	$60,868	$60,868	$730,416
5															
6	Unamortized Regulatory Liability - Book/Tax Timing Diff	($3,652,117)	($3,591,249)	($3,530,381)	($3,469,513)	($3,408,645)	($3,347,777)	($3,286,909)	($3,226,041)	($3,165,173)	($3,104,305)	($3,043,437)	($2,982,569)	($2,921,701)	
7															
8	Average Unamortized Regulatory Liability - Book/Tax Timing Difference		($3,621,683)	($3,560,815)	($3,499,947)	($3,439,079)	($3,378,211)	($3,317,343)	($3,256,475)	($3,195,607)	($3,134,739)	($3,073,871)	($3,013,003)	($2,952,135)	
9															
10	Return on Unamortized Regulatory Liability - Book/Tax Timing Difference														
11	Equity Component [1]		($15,152)	($14,898)	($14,643)	($14,388)	($14,134)	($13,879)	($13,509)	($13,257)	($13,004)	($12,752)	($12,499)	($12,247)	($164,362)
12															
13	Equity Comp. grossed up for taxes [1]		($20,075)	($19,738)	($19,400)	($19,063)	($18,726)	($18,388)	($17,898)	($17,564)	($17,229)	($16,894)	($16,560)	($16,225)	($217,761)
14															
15	Debt Component (Line 8 * debt rate / 12) [2]		($4,077)	($4,008)	($3,940)	($3,871)	($3,803)	($3,734)	($3,674)	($3,605)	($3,537)	($3,468)	($3,399)	($3,331)	($44,445)
16															
17	Total Return Requirements (Line 13 + 15)		($24,152)	($23,746)	($23,340)	($22,934)	($22,528)	($22,122)	($21,572)	($21,169)	($20,766)	($20,362)	($19,959)	($19,556)	($262,206)
18	Total Recoverable Costs (Line 4 + 13 + 15)		($85,020)	($84,614)	($84,208)	($83,802)	($83,396)	($82,990)	($82,440)	($82,037)	($81,634)	($81,230)	($80,827)	($80,424)	($992,622)
19															

20 [1] The Gross-up factor for taxes is 0.75478, which reflects the Federal Income Tax Rate of 21%. The monthly Equity Component for the Jan. – Jun. 2020 period is 5.0206%, based on May 2019 ROR Surveillance Report

21 and reflects a 10.55% return on equity, and the monthly Equity Component for the Jul. – Dec. 2020 period is 4.9781% based on the May 2020 ROR Surveillance Report and reflects a 10.55% return on equity.

22 [2] The Debt Component for the Jan. – Jun. 2020 period is 1.3507% is based on the May 2019 Earnings Surveillance Report and the Debt Component for the Jul. – Dec. 2020 period is 1.3538% based on the May 2020 Earnings Surveillance Report.

23 [3] Recovery of the Cedar Bay Transaction is based on the settlement agreement approved by the FPSC in Docket No. 150075-EI, Order No. PSC-15-0401-AS-EI.

24

25 Totals may not add due to rounding

Line No.	Line	Beginning of Period	a-Jan - 2020	a-Feb - 2020	a-Mar - 2020	a-Apr - 2020	a-May - 2020	a-Jun - 2020	Jul - 2020	Aug - 2020	Sep - 2020	Oct - 2020	Nov - 2020	Dec - 2020	Total
1															
2	Regulatory Asset - Loss of PPA [3]		$300,999,999	$296,819,444	$292,638,888	$288,458,333	$284,277,777	$280,097,221	$275,916,666	$271,736,110	$267,555,555	$263,374,999	$259,194,444	$255,013,888	
3															
4	Regulatory Asset - Loss of PPA Amort		$4,180,556	$4,180,556	$4,180,556	$4,180,556	$4,180,556	$4,180,556	$4,180,556	$4,180,556	$4,180,556	$4,180,556	$4,180,556	$4,180,556	$50,166,667
5															
6	Unamortized Regulatory Asset - Loss of PPA	$300,999,999	$296,819,444	$292,638,888	$288,458,333	$284,277,777	$280,097,221	$275,916,666	$271,736,110	$267,555,555	$263,374,999	$259,194,444	$255,013,888	$250,833,333	
7															
8	Average Unamortized Regulatory Asset - Loss of PPA		$298,909,722	$294,729,166	$290,548,610	$286,368,055	$282,187,499	$278,006,944	$273,826,388	$269,645,833	$265,465,277	$261,284,721	$257,104,166	$252,923,610	
9															
10	Return on Unamortized Regulatory Asset - Loss of PPA only														
11	Equity Component [1]		$1,250,578	$1,233,088	$1,215,597	$1,198,107	$1,180,616	$1,163,125	$1,135,941	$1,118,599	$1,101,256	$1,083,914	$1,066,571	$1,049,228	$13,796,621
12															
13	Equity Comp. grossed up for taxes [1]		$1,656,874	$1,633,701	$1,610,528	$1,587,355	$1,564,182	$1,541,009	$1,504,993	$1,482,016	$1,459,039	$1,436,062	$1,413,085	$1,390,108	$18,278,953
14															
15	Debt Component (Line 8 * debt rate / 12) [2]		$336,453	$331,747	$327,042	$322,336	$317,630	$312,925	$308,931	$304,214	$299,498	$294,781	$290,065	$285,348	$3,730,970
16															
17	Total Return Requirements (Line 19 + 21)		$1,993,327	$1,965,448	$1,937,570	$1,909,691	$1,881,812	$1,853,933	$1,813,924	$1,786,231	$1,758,537	$1,730,844	$1,703,150	$1,675,457	$22,009,923
18	Total Recoverable Costs (Line 4 + 12 + 23)		$6,173,883	$6,146,004	$6,118,125	$6,090,246	$6,062,368	$6,034,489	$5,994,480	$5,966,786	$5,939,093	$5,911,399	$5,883,706	$5,856,012	$72,176,590
19															
20															

21 [1] The Gross-up factor for taxes is 0.75478, which reflects the Federal Income Tax Rate of 21%. The monthly Equity Component for the Jan. – Jun. 2020 period is 5.0206%, based on May 2019 ROR Surveillance Report

22 and reflects a 10.55% return on equity, and the monthly Equity Component for the Jul. – Dec. 2020 period is 4.9781% based on the May 2020 ROR Surveillance Report and reflects a 10.55% return on equity.

23 [2] The Debt Component for the Jan. – Jun. 2020 period is 1.3507% is based on the May 2019 Earnings Surveillance Report and the Debt Component for the Jul. – Dec. 2020 period is 1.3538% based on the May 2020 Earnings Surveillance Report.

24 [3] Recovery of the Indiantown Transaction is based on the settlement agreement approved by the FPSC in Docket No. 160154-EI, Order No. PSC-16-0506-FOF-EI.

25

26 Totals may not add due to rounding

Line No.	Line	Beginning Balance	a-Jan - 2020	a-Feb - 2020	a-Mar - 2020	a-Apr - 2020	a-May - 2020	a-Jun - 2020	Jul - 2020	Aug - 2020	Sep - 2020	Oct - 2020	Nov - 2020	Dec - 2020	Total
1	Regulatory Asset - SJRPP Transaction Shutdown Payment [(3)]		$43,234,783	$41,269,566	$39,304,348	$37,339,131	$35,373,913	$33,408,696	$31,443,479	$29,478,261	$27,513,044	$25,547,826	$23,582,609	$21,617,392	
2	Regulatory Asset - SJRPP Transaction Shutdown Payment Amortization		$1,965,217	$1,965,217	$1,965,217	$1,965,217	$1,965,217	$1,965,217	$1,965,217	$1,965,217	$1,965,217	$1,965,217	$1,965,217	$1,965,217	$23,582,609
3	Unamortized Regulatory Asset - SJRPP Transaction Shutdown Payment	$43,234,783	$41,269,566	$39,304,348	$37,339,131	$35,373,913	$33,408,696	$31,443,479	$29,478,261	$27,513,044	$25,547,826	$23,582,609	$21,617,392	$19,652,174	
4															
5	Other regulatory liability - SJRPP Suspension Liability		($4,736,980)	($4,521,663)	($4,306,346)	($4,091,028)	($3,875,711)	($3,660,394)	($3,445,076)	($3,229,759)	($3,014,442)	($2,799,125)	($2,583,807)	($2,368,490)	
6	Other regulatory liability - SJRPP Suspension Liability Amortization (Refund)		($215,317)	($215,317)	($215,317)	($215,317)	($215,317)	($215,317)	($215,317)	($215,317)	($215,317)	($215,317)	($215,317)	($215,317)	($2,583,807)
7	Unamortized Regulatory Liability - SJRPP Suspension Liability	($4,736,980)	($4,521,663)	($4,306,346)	($4,091,028)	($3,875,711)	($3,660,394)	($3,445,076)	($3,229,759)	($3,014,442)	($2,799,125)	($2,583,807)	($2,368,490)	($2,153,173)	
8															
9	Average Net Unamortized Regulatory Asset/Liab (Lines 3 + 7)		$37,622,853	$35,872,953	$34,123,053	$32,373,152	$30,623,252	$28,873,352	$27,123,452	$25,373,552	$23,623,652	$21,873,752	$20,123,852	$18,373,951	
10															
11	Equity Component		$157,406	$150,085	$142,764	$135,443	$128,122	$120,800	$112,519	$105,260	$98,000	$90,741	$83,482	$76,223	$1,400,845
12	Equity Comp. grossed up for taxes		$208,546	$198,846	$189,146	$179,446	$169,746	$160,047	$149,075	$139,457	$129,839	$120,222	$110,604	$100,986	$1,855,960
13	Debt Component (Line 9 x debt rate / 12)		$42,348	$40,379	$38,409	$36,439	$34,470	$32,500	$30,601	$28,626	$26,652	$24,678	$22,704	$20,729	$378,535
14															
15	Total Return Requirements (Line 12 + 13)		$250,894	$239,224	$227,555	$215,886	$204,216	$192,547	$179,675	$168,083	$156,492	$144,900	$133,308	$121,716	$2,234,495
16															
17	Other SJRPP Transaction Items [(4)]														
18	SJRPP Deferred Interest Amortization (Refund)		($269,182)	($269,182)	($269,182)	($269,182)	($269,182)	($269,182)	($269,182)	($269,182)	($269,182)	($269,182)	($269,182)	($269,182)	($3,230,181)
19	SJRPP Article 8 PPA Dismantlement Accrual Amortization (Refund)		($867,898)	($867,898)	($867,898)	($867,898)	($867,898)	($867,898)	($867,898)	($867,898)	($867,898)	($867,898)	($867,898)	($867,898)	($10,414,774)
20															
21	Total Recoverable Expenses (Lines 2 + 6 + 15 + 18 + 19)		$863,715	$852,045	$840,376	$828,706	$817,037	$805,367	$792,496	$780,904	$769,312	$757,720	$746,128	$734,536	$9,588,341
22															
23															
24															

25 [(1)] The Gross-up factor for taxes is 0.75478, which reflects the Federal Income Tax Rate of 21%. The monthly Equity Component for the Jan. – Jun. 2020 period is 5.0206%, based on May 2019 ROR Surveillance Report

26 and reflects a 10.55% return on equity, and the monthly Equity Component for the Jul. – Dec. 2020 period is 4.9781% based on the May 2020 ROR Surveillance Report and reflects a 10.55% return on equity.

27 [(2)] The Debt Component for the Jan. – Jun. 2020 period is 1.3507% is based on the May 2019 Earnings Surveillance Report and the Debt Component for the Jul. – Dec. 2020 period is 1.3538% based on the May 2020 Earnings Surveillance Report.

28 [(3)] Recovery of the SJRPP Transaction over a 46 month period is based on the settlement agreement approved by the FPSC in Docket No. 20170123-EI Order No. PSC-2017-0415-AS-EI.

29 [(4)] The total amount of SJRPP Deferred Interest and Article 8 PPA Dismantlement Accrual to refund is $12.4M and $39.9M, respectively. The unamortized balances for these regulatory liabilities are a reflected in rate base.

30

31 Totals may not add due to rounding

Line No.	E1-A True-Up Summary	Total
1	End of Period True-Up [1]	$77,114,247
2		
3	Less - Actual Estimated True-up for the same period [2]	$128,735,937
4		
5	Net True-up for the period	($51,621,690)
6		
7	[1] Page 2, Column 16, Lines 41 & 42.	
8	[2] Approved in FPSC Final Order PSC-2019-0484-FOF-EI	
9		
10	( ) Reflects under-recovery	
11		
12	Totals may not add due to rounding	

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20200001-EI EXHIBIT: 14
PARTY: FLORIDA POWER & LIGHT COMPANY – DIRECT
DESCRIPTION: R.B.Deaton RBD-5

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
Line No.	True-up	True Up Line	a-Jan - 2019	a-Feb - 2019	a-Mar - 2019	a-Apr - 2019	a-May - 2019	a-Jun - 2019	a-Jul - 2019	a-Aug - 2019	a-Sep - 2019	a-Oct - 2019	a-Nov - 2019	a-Dec - 2019	2019
1	**Fuel Costs & Net Power Transacti**	Fuel Cost of System Net Generation [1]	$247,645,037	$210,407,736	$239,033,820	$240,339,290	$265,852,130	$260,852,387	$257,576,253	$242,828,562	$248,374,166	$242,758,953	$217,693,436	$195,175,246	$2,868,537,018
2		Fuel Cost of Stratified Sales	($2,502,014)	($1,682,735)	($1,748,714)	($2,688,498)	($2,785,905)	($3,537,668)	($3,412,466)	($3,740,146)	($3,166,233)	($3,555,816)	($2,903,428)	($2,908,818)	($34,632,440)
3		Scherer Coal Cars Depreciation & Return													
4		Rail Car Lease (Cedar Bay/ICL/SJRPP)	$431,592	$229,587	$517,637	$288,456	$312,932	$111,960	$175,886	$257,232	$36,235	$163,992	$113,488	$144,570	$2,783,566
5		Fuel Cost of Power Sold (Per A6)	($9,633,494)	($7,019,582)	($6,246,138)	($4,379,818)	($2,828,622)	($2,657,301)	($3,326,575)	($4,855,300)	($3,300,967)	($1,789,066)	($4,980,872)	($3,757,953)	($54,775,689)
6		Gains from Off-System Sales (Per A6)	($4,922,077)	($2,729,301)	($2,317,588)	($1,920,408)	($951,695)	($938,229)	($1,122,124)	($1,962,658)	($1,297,484)	($1,215,518)	($2,858,588)	($1,939,408)	($24,175,079)
7		Fuel Cost of Purchased Power (Per A7)	$2,985,541	$1,982,779	$2,690,113	$2,385,026	$2,396,171	$3,608,732	$2,853,022	$1,945,537	$3,919,643	$2,048,816	$2,532,517	$2,348,824	$31,696,720
8		Energy Payments to Qualifying Facilities (Per A8)	$590,447	$379,280	$398,998	$336,858	$462,632	$639,663	$518,259	$374,924	$596,212	$380,420	$544,180	$343,633	$5,565,507
9		Energy Cost of Economy Purchases (Per A9)	$30,784	$32,530	$559,838	$610,393	$5,635,526	$10,448,887	$2,835,006	$63,539	$4,413,099	$848,272	$55,519	$1,785	$25,535,179
10		Total Fuel Costs & Net Power Transactions	$234,625,816	$201,600,293	$232,887,967	$234,971,299	$268,093,168	$268,528,431	$256,097,261	$234,911,690	$249,574,672	$239,640,053	$210,196,252	$189,407,878	$2,820,534,781
11															
12	**Incremental Optimization Costs**	Incremental Personnel, Software, and Hardware Costs	$45,273	$40,940	$38,239	$40,305	$56,630	$42,240	$46,373	$48,540	$42,427	$46,741	$43,306	$42,051	$533,064
13		Variable Power Plant O&M Attributable to Off-System Sales (Per A6)	$289,804	$224,878	$203,849	$141,000	$87,966	$84,664	$94,130	$155,136	$102,312	$50,107	$182,998	$137,428	$1,754,273
14		Variable Power Plant O&M Avoided due to Economy Purchases (Per A9)	($1,067)	($832)	($8,941)	($9,068)	($74,779)	($145,473)	($39,516)	($1,659)	($58,877)	($16,924)	($1,025)	($111)	($358,271)
15		Total Incremental Optimization Costs	$334,010	$264,985	$233,147	$172,237	$69,817	($18,568)	$100,987	$202,016	$85,862	$79,924	$225,279	$179,369	$1,929,065
16															
17		Dodd Frank Fees											($375)		($375)
18															
19	**Adjustments to Fuel Cost**	Energy Imbalance Fuel Revenues	($178,221)	($133,355)	($3,715)	($59,315)	($173,941)	($26,135)	($109,850)	($44,363)	($80,032)	($56,987)	($96,327)	($37,185)	($999,428)
20		Inventory Adjustments	($53,094)	$18,214	($179,394)	$360,284	$705,754	($1,110,949)	$59,322	($49,336)	$37,708	($48,952)	$45,022	$19,252	($196,170)
21		Non Recoverable Oil/Tank Bottoms			$232,871	($549,227)		($1,051,361)		$1,084	($1,084)				($1,367,717)
22		Other O&M Expense [4]				$1,554	$205,738		$196,696	$28,633	$132,828		$8,400		$573,849
23		Adjusted Total Fuel Costs & Net Power Transactions	$234,728,511	$201,750,137	$233,170,876	$234,896,831	$268,900,537	$266,321,419	$256,344,416	$235,049,725	$249,749,953	$239,614,039	$210,378,250	$189,569,313	$2,820,474,006
24															
25	**kWh Sales**	Jurisdictional kWh Sales	8,090,450,684	7,361,664,859	7,987,648,669	8,430,422,795	9,195,507,367	10,476,195,510	10,982,152,510	10,850,301,676	11,097,861,893	10,385,466,073	9,277,887,548	7,793,867,458	111,929,427,042
26		Sales for Resale (excluding Stratified Sales)	398,798,783	418,248,548	387,890,789	426,072,948	452,801,248	540,722,792	564,829,647	577,658,348	563,995,111	542,101,846	538,701,537	409,243,236	5,821,064,833
27		Total Sales	8,489,249,467	7,779,913,407	8,375,539,458	8,856,495,743	9,648,308,615	11,016,918,302	11,546,982,157	11,427,960,024	11,661,857,004	10,927,567,919	9,816,589,085	8,203,110,694	117,750,491,875
28															
29		Jurisdictional % of Total kWh Sales	95.30231%	94.62399%	95.36877%	95.18915%	95.30694%	95.09189%	95.10842%	94.94522%	95.16376%	95.03914%	94.51233%	95.01112%	95.05644%
30															
31	**True-Up Calculation**	Jurisdictional Fuel Revenues (Net of Revenue Taxes)	$216,746,520	$194,169,194	$211,711,391	$211,291,072	$233,391,232	$269,773,583	$284,563,200	$280,559,650	$287,743,740	$266,856,876	$235,011,577	$193,673,527	$2,885,491,562
32															
33	**Fuel Adjustment Revenues Not Applicable to Period**														
34		Prior Period True-Up (Collected)/Refunded This Period [2]	($9,311,710)	($9,311,710)	($9,311,710)	($9,311,710)	($9,311,710)	($9,311,710)	($9,311,710)	($9,311,710)	($9,311,710)	($9,311,710)	($9,311,710)	($9,311,710)	($111,740,516)
35		GPIF, Net of Revenue Taxes [3]	($487,810)	($487,810)	($487,810)	($487,810)	($487,810)	($487,810)	($487,810)	($487,810)	($487,810)	($487,810)	($487,810)	($487,810)	($5,853,723)
36		Incentive Mechanism, Net of Revenue Taxes [5]	($183,580)	($183,580)	($183,580)	($183,580)	($183,580)	($183,580)	($183,580)	($183,580)	($183,580)	($183,580)	($183,580)	($183,580)	($2,202,961)
37		Retail Fuel Revenues Applicable to Period	$206,763,420	$184,186,094	$201,728,291	$201,307,972	$223,408,132	$259,790,483	$274,580,100	$270,576,550	$277,760,640	$256,873,776	$225,028,477	$183,690,427	$2,765,694,362
38		Adjusted Total Fuel Costs & Net Power Transactions	234,728,511	201,750,137	233,170,876	234,896,831	268,900,537	266,321,419	256,344,416	235,049,725	249,749,953	239,614,039	210,378,250	189,569,313	2,820,474,006
39		Retail % of Total kWh Sales	95.30231%	94.62399%	95.36877%	95.18915%	95.30694%	95.09189%	95.10842%	94.94522%	95.16376%	95.03914%	94.51233%	95.01112%	95.05644%
40		Juris. Total Fuel Costs & Net Power Transactions	224,012,638	191,169,386	222,681,294	223,907,096	256,637,103	253,602,088	244,144,013	223,478,683	238,001,809	228,043,663	199,109,764	180,362,283	2,685,149,820
41		True-Up Provision for the Month-Over/(Under) Recovery	($17,249,218)	($6,983,292)	($20,953,003)	($22,599,124)	($33,228,971)	$6,188,395	$30,436,087	$47,097,867	$39,758,831	$28,830,114	$25,918,713	$3,328,144	$80,544,543
42		Interest Provision for the Month	($375,831)	($381,455)	($396,459)	($424,391)	($454,824)	($453,596)	($375,629)	($270,197)	($173,846)	($91,289)	($32,969)	$191	($3,430,296)
43		True-Up & Interest Prov. Beg of Period-Over/(Under) Recovery	($111,740,516)	($120,053,856)	($118,106,894)	($130,144,645)	($143,856,451)	($168,228,537)	($153,182,029)	($113,809,861)	($57,670,482)	($8,773,787)	$29,276,748	$64,474,201	($111,740,516)
44		Deferred True-up Beginning of Period - Over/(Under) Recovery [6]	($70,653,405)	($70,653,405)	($70,653,405)	($70,653,405)	($70,653,405)	($70,653,405)	($70,653,405)	($70,653,405)	($70,653,405)	($70,653,405)	($70,653,405)	($70,653,405)	($70,653,405)
45		Prior Period True-Up Collected/(Refunded) This Period	$9,311,710	$9,311,710	$9,311,710	$9,311,710	$9,311,710	$9,311,710	$9,311,710	$9,311,710	$9,311,710	$9,311,710	$9,311,710	$9,311,710	$111,740,516
46		End of Period Net True-up Amount Over/(Under) Recovery	($190,707,261)	($188,760,299)	($200,798,050)	($214,509,856)	($238,881,942)	($223,835,434)	($184,463,266)	($128,323,887)	($79,427,192)	($41,376,657)	($6,179,204)	$6,460,842	$6,460,842
47															
48															
49	[1] Actuals include various adjustments as noted on the A-Schedules.														
50	[2] Prior Period 2018 Actual/Estimated True-up.														
51	[3] Generating Performance Incentive Factor is (($5,857,941/12) x 99.9280%) - See Order No. PSC-2018-0610-FOF-EI														
52	[4] Other Fuel Expense consists of nuclear fuel design software maintenance costs.														
53	[5] Jurisdictionalized Incentive Mechanism - FPL Portion is (($2,204,548/12) x 99.9280%) - See Order No. PSC-2018-0610-FOF-EI														
54	[6] 2018 Final True-up.														
55															
56		Totals may not add due to rounding.													

(1)	(2)	(3)	(4)	(5)	(6)	(7)
Line No.	True-up	True Up Line	2019			
			Actuals	Actual/Estimated	Diff $	Diff %
1	**Fuel Costs & Net Power Transactions**	Fuel Cost of System Net Generation [1]	$2,868,537,018	$2,742,695,965	$125,841,052	4.6%
2		Fuel Cost of Stratified Sales	($34,632,440)	($28,202,880)	($6,429,559)	22.8%
3		Rail Car Lease (Cedar Bay/ICL/SJRPP)	$2,783,566	$2,807,537	($23,971)	(0.9%)
4		Fuel Cost of Power Sold (Per A6)	($54,775,689)	($52,136,444)	($2,639,245)	5.1%
5		Gains from Off-System Sales (Per A6)	($24,175,079)	($21,802,243)	($2,372,836)	10.9%
6		Fuel Cost of Purchased Power (Per A7)	$31,696,720	$30,893,610	$803,109	2.6%
7		Energy Payments to Qualifying Facilities (Per A8)	$5,565,507	$5,457,362	$108,146	2.0%
8		Energy Cost of Economy Purchases (Per A9)	$25,535,179	$24,108,353	$1,426,826	5.9%
9		Total Fuel Costs & Net Power Transactions	$2,820,534,781	$2,703,821,260	$116,713,522	4.3%
10						
11	**Incremental Optimization Costs**	Incremental Personnel, Software, and Hardware Costs	$533,064	$526,330	$6,734	1.3%
12		Variable Power Plant O&M Attributable to Off-System Sales (Per A6)	$1,754,273	$1,629,911	$124,361	7.6%
13		Variable Power Plant O&M Avoided due to Economy Purchases (Per A9)	($358,271)	($408,282)	$50,010	(12.2%)
14		Total Incremental Optimization Costs	$1,929,065	$1,747,960	$181,106	10.4%
15		Dodd Frank Fees	($375)	-	($375)	N/A
16						
17	**Adjustments to Fuel Cost**	Energy Imbalance Fuel Revenues	($999,428)	($570,875)	($428,553)	75.1%
18		Inventory Adjustments	($196,170)	($259,185)	$63,015	(24.3%)
19		Non Recoverable Oil/Tank Bottoms	($1,367,717)	($1,367,716)	($0)	0.0%
20		Other O&M Expense [2]	$573,849	$565,522	$8,327	1.5%
21		Adjusted Total Fuel Costs & Net Power Transactions	$2,820,474,006	$2,703,936,965	$116,537,041	4.3%
22						
23	**kWh Sales**	Jurisdictional kWh Sales	111,929,427,042	110,337,852,692	1,591,574,350	1.4%
24		Sales for Resale (excluding Stratified Sales)	5,821,064,833	5,237,747,569	583,317,264	11.1%
25		Total Sales	117,750,491,875	115,575,600,261	2,174,891,614	1.9%
26						
27		Jurisdictional % of Total Sales	95.05644%	95.46812%		
28						
29	**True-Up Calculation**	Jurisdictional Fuel Revenues (Net of Revenue Taxes)	$2,885,491,562	$2,835,888,086	$49,603,476	1.7%
30						
31	**Fuel Adjustment Revenues Not Applicable to**					
32		Prior Period True-Up (Collected)/Refunded This Period [3]	($111,740,516)	($111,740,516)	-	0.0%
33		GPIF, Net of Revenue Taxes [4]	($5,853,723)	($5,853,723)	-	N/A
34		Incentive Mechanism, Net of Revenue Taxes [5]	($2,202,961)	($2,202,961)	-	N/A
35		Jurisdictional Fuel Revenues Applicable to Period	$2,765,694,362	$2,716,090,886	$49,603,476	1.7%
36		Adjusted Total Fuel Costs & Net Power Transactions	2,820,474,006	2,703,936,965	116,537,041	4.3%
37		Jurisdictional Sales % of Total kWh Sales	95.05644%	95.46812%		
38		Juris. Total Fuel Costs & Net Power Transactions	$2,685,149,820	$2,584,104,916	$101,044,904	3.9%
39		True-Up Provision for the Month-Over/(Under) Recovery	$80,544,543	$131,985,970	($51,441,428)	(39.0%)
40		Interest Provision for the Month	($3,430,296)	($3,250,033)	($180,263)	5.5%
41		True-Up & Interest Prov. Beg of Period-Over/(Under) Recovery	($111,740,516)	($111,740,516)	-	N/A
42		Deferred True-up Beginning of Period - Over/(Under) Recovery [6]	($70,653,405)	($70,653,405)	-	N/A
43		Prior Period True-Up Collected/(Refunded) This Period	$111,740,516	$111,740,516	-	N/A
44		End of Period Net True-up Amount Over/(Under) Recovery	$6,460,842	$58,082,532	($51,621,690)	(88.9%)
45						
46						

47 [1] Actuals include various adjustments as noted on the A-Schedules.

48 [2] Other Fuel Expense consists of nuclear fuel design software maintenance costs.

49 [3] Prior Period 2018 Actual/Estimated True-up.

50 [4] Generating Performance Incentive Factor is (($5,857,941/12) x 99.9280%) - See Order No. PSC-2018-0610-FOF-EI

51 [5] Jurisdictionalized Incentive Mechanism - FPL Portion is (($2,204,548/12) x 99.9280%) - See Order No. PSC-2018-0610-FOF-EI

52 [6] 2018 Final True-up.

APPENDIX II
FUEL COST RECOVERY
2021 E-SCHEDULES

FOR THE PERIOD JANUARY 2021 THROUGH DECEMBER 2021

RBD-6
DOCKET NO. 20200001-EI
FPL WITNESS: RENAE B. DEATON
EXHIBIT ___________
PAGES 1-102
SEPTEMBER 3, 2020

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20200001-EI EXHIBIT: 15
PARTY: FLORIDA POWER & LIGHT COMPANY – DIRECT
DESCRIPTION: R.B.Deaton RBD-6

APPENDIX II
FUEL COST RECOVERY
2021 E SCHEDULES - JAN 2021 THROUGH DEC 2021

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ESTIMATED FOR THE PERIOD OF: JANUARY 2021 THROUGH DECEMBER 2021

(1)	(2)	(3)	(4)	(5)
Line No.		Dollars	MWH	Cents/KWH
1	Fuel Cost of System Net Generation (E3)	$2,754,998,906	124,044,758	2.2210
2	Fuel Cost of Stratified Sales	($14,823,385)	(593,724)	2.4967
3	Rail Car Lease (Cedar Bay/Indiantown)	$1,980,447		N/A
4	Adjustments to Fuel Cost	$572,960		N/A
5	TOTAL COST OF GENERATED POWER	$2,742,728,928	123,451,034	2.2217
6	Fuel Cost of Purchased Power (Exclusive of Economy) (E7)	29,909,976	1,477,713	2.0241
7	Energy Cost of Economy Purchases (Per E9)	$9,019,180	347,180	2.5978
8	Energy Payments to Qualifying Facilities (Per E8)	$5,919,852	312,315	1.8955
9	TOTAL COST OF PURCHASED POWER	$44,849,008	2,137,208	2.0985
10	TOTAL AVAILABLE MWH (LINE 5 + LINE 9)		125,588,242	
11	Fuel Cost of Economy and Other Power Sales (E6)	($52,303,995)	(2,598,470)	2.0129
12	Gains from Off-System Sales (Per E6)	($25,272,200)		N/A
13	Fuel Cost of Unit Power Sales (SL2 Partpts) (E6)	($2,826,064)	(571,679)	0.4943
14	TOTAL FUEL COST AND GAINS OF POWER SALES	($80,402,260)	(3,170,149)	2.5362
15	Incremental Personnel, Software, and Hardware Costs	$451,676		N/A
16	Variable Power Plant O&M Attributable to Off-System Sales (Per E6)	$1,689,006		N/A
17	Variable Power Plant O&M Avoided due to Economy Purchases (Per E9)	($225,667)		N/A
18	Total Incremental Optimization Costs	$1,915,015		
19	Total Fuel Costs & Net Power Transactions	$2,709,090,691	122,418,093	2.2130
20	Net Unbilled Sales (1)	$2,053,778	92,806	0.0018
21	Company Use (1)	$2,709,091	122,418	0.0023
22	T & D Losses (1)	$116,490,900	5,263,978	0.0996
23	System MWH Sales (Excluding Stratified Sales)	$2,709,090,691	116,938,891	2.3167
24	Wholesale MWH Sales (Excluding Stratified Sales)	$118,752,990	5,126,011	2.3167
25	Jurisdictional MWH Sales	$2,590,337,700	111,812,880	2.3167
26	Jurisdictional Loss Multiplier	$3,522,859		1.00136
27	Jurisdictional MWH Sales Adjusted for Line Losses	$2,593,860,560	111,812,880	2.3198
28	NET TRUE-UP (OVER)/UNDER RECOVERY (E1-A)	$20,669,910	111,812,880	0.0185
29	TOTAL JURISDICTIONAL FUEL COST	$2,614,530,470	111,812,880	2.3383
30	Revenue Tax Factor	1,882,462		1.00072
31	Fuel Factor Adjusted for Taxes	$2,616,412,932	111,812,880	2.3400
32	GPIF (2)	$8,125,681	111,812,880	0.0073
33	Jurisdictional Incentive Mechanism - FPL Portion	$8,703,535	111,812,880	0.0078
34	SolarTogether (ST) Credit	$98,939,400	111,812,880	0.0885
35	Fuel Factor Adjusted for GPIF (Lines 31 through 34)	$2,732,181,548	111,812,880	2.4436
36	FUEL FACTOR ROUNDED TO NEAREST .001 CENTS/KWH			2.444
37				
38	(1) For informational purposes only			
39	(2) Calculation based on Jurisdictional KWH sales			
40				
41	Note: Totals may not add due to rounding.			

ESTIMATED FOR THE PERIOD OF: JANUARY 2021 THROUGH DECEMBER 2021

Line No.		Annual Total
1	Actual/Estimated over/(under) recovery [1]	$30,951,780
2	Final over/(under) recovery [2]	($51,621,690)
3	Total over/(under) recovery to be included in projected period [3]	($20,669,910)
4		
5	Total Jurisdictional Sales (MWH)	111,812,880
6		
7	True-Up Factor (cents/kWh)	(0.0185)
8		
9	Note: Totals may not add due to rounding.	
10		
11	[1] Actual/Estimated over/(under) recovery for January 2020 - December 2020	
12	[2] Final True-up over/(under) recovery for January 2019 - December 2019	
13	[3] Projected Period January 2021 - December 2021 (Schedule E1, Line 28)	
14		
15	Note: Totals may not add due to rounding.	

ESTIMATED FOR THE PERIOD OF: JANUARY 2021 THROUGH DECEMBER 2021

Line No.		Annual Total
1	TOTAL AMOUNT OF ADJUSTMENTS	$136,438,526
2	A. GENERATING PERFORMANCE INCENTIVE REWARD (PENALTY)	$8,125,681
3	B. TRUE-UP (OVER)/UNDER RECOVERED	$20,669,910
4	C. JURISDICTIONALIZED INCENTIVE MECHANISM - FPL PORTION	$8,703,535
5	D. FPL SOLARTOGETHER CREDIT	$98,939,400
6		
7	TOTAL JURISDICTIONAL SALES (MWH)	111,812,880
8		
9	ADJUSTMENT FACTORS (cents/kWh)	0.1220
10	A. GENERATING PERFORMANCE INCENTIVE FACTOR	0.0073
11	B. TRUE-UP FACTOR	0.0185
12	C. JURISDICTIONALIZED INCENTIVE MECHANISM - FPL PORTION	0.0078
13	D. FPL SOLARTOGETHER CREDIT	0.0885
14		
15	Note: Totals may not add due to rounding.	

FOR THE PERIOD JANUARY 2021 THROUGH DECEMBER 2021

Line No.	CALCULATION OF JURISDICTIONAIZED 2019 Incentive Mechanism Gains - FPL Portion		Annual Total
1	2019 Incentive Mechanism Gains - FPL Portion [(1)]	$	9,149,588
2			
3	2019 Actual \Retail kWh sales		111,929,427
4	2019 Actual Total System kWh sales		117,750,492
5	2019 Actual Average Jurisdictional % [(2)]		95.05644%
6			
7	Jurisdictionalized 2019 Incentive Mechanism Gains - FPL Portion	$	8,697,273
8			
9	Revenue Tax Factor		1.00072
10			
11	Jurisdictionalized 2019 Incentive Mechanism Gains - FPL Portion Adjusted for Revenue Taxes	$	8,703,535
12			
13	2021 Projected kWh Sales		111,812,880
14			
15	2019 Jurisdictional Incentive Mechanism Gains - FPL Portion for Recovery in 2021 CENTS/KWH	$	0.0078
16			
17	[(1)] Reflected on Exhibit GJY-1, filed on March 2, 2020		
18	[(2)] Reflected on Schedule E1-B, filed on March 2, 2020		
19			
20			

ESTIMATED FOR THE PERIOD OF: JANUARY 2021 THROUGH DECEMBER 2021

Line No.	E1-D Schedule	Marginal Cost	Jan - 2021	Feb - 2021	Mar - 2021	Apr - 2021	May - 2021	Jun - 2021	Jul - 2021	Aug - 2021	Sep - 2021	Oct - 2021	Nov - 2021	Dec - 2021	Total
1	On-Peak Period	System MWH Requirements	2,157,822	2,183,836	2,505,118	3,416,588	3,355,781	3,993,621	4,143,236	4,193,734	3,832,526	3,476,463	2,313,913	2,436,408	38,009,046
2		Marginal Cost	47,083,676	47,061,666	54,686,726	74,891,609	72,585,543	95,567,351	109,298,566	115,537,372	102,481,745	85,416,696	47,018,712	48,849,980	900,479,641
3		Average Marginal Cost (¢/kWh)	2.182	2.155	2.183	2.192	2.163	2.393	2.638	2.755	2.674	2.457	2.032	2.005	2.369
4															
5	Off-Peak Period	System MWH Requirements	7,143,445	6,349,652	6,986,306	6,363,751	7,827,159	7,562,156	8,257,180	8,361,310	7,708,737	7,332,239	6,845,681	6,864,411	87,602,027
6		Marginal Cost	133,510,987	122,548,284	134,556,254	111,365,643	136,740,468	137,026,267	154,161,551	159,617,408	142,611,635	131,906,980	121,990,035	124,314,483	1,610,349,992
7		Average Marginal Cost (¢/kWh)	1.869	1.930	1.926	1.750	1.747	1.812	1.867	1.909	1.850	1.799	1.782	1.811	1.838
8															
9	Total Period	System MWH Requirements	9,301,267	8,533,488	9,491,424	9,780,339	11,182,940	11,555,777	12,400,416	12,555,044	11,541,263	10,808,702	9,159,594	9,300,819	125,611,073
10		Marginal Cost	180,594,663	169,609,949	189,242,980	186,257,251	209,326,011	232,593,617	263,460,116	275,154,780	245,093,380	217,323,676	169,008,748	173,164,464	2,510,829,634
11		Average Marginal Cost (¢/kWh)	1.942	1.988	1.994	1.904	1.872	2.013	2.125	2.192	2.124	2.011	1.845	1.862	1.999
12															
13	On-Peak Period	Marginal Fuel Cost Weighting Multiplier													1.185
14	Off-Peak Period	Marginal Fuel Cost Weighting Multiplier													0.920
15	Average	Marginal Fuel Cost Weighting Multiplier													1.000
16															
17															
18		Note: Totals may not add due to rounding.													

ESTIMATED FOR THE PERIOD OF: JANUARY 2021 THROUGH DECEMBER 2021

Line No.	E1-D Schedule	SDTR	Jun - 2021	Jul - 2021	Aug - 2021	Sep - 2021	Total
1	On-Peak Period	System MWH Requirements	1,389,360	1,437,314	1,452,890	1,332,290	5,611,854
2		Marginal Cost	38,763,144	45,893,436	49,151,269	43,565,883	177,373,732
3		Average Marginal Cost (¢/kWh)	2.790	3.193	3.383	3.270	3.161
4							
5	Off-Peak Period	System MWH Requirements	10,166,417	10,963,102	11,102,154	10,208,973	42,440,646
6		Marginal Cost	192,145,281	215,205,692	223,486,360	199,177,063	830,014,397
7		Average Marginal Cost (¢/kWh)	1.890	1.963	2.013	1.951	1.956
8							
9	Total Period	System MWH Requirements	11,555,777	12,400,416	12,555,044	11,541,263	48,052,500
10		Marginal Cost	230,908,425	261,099,128	272,637,629	242,742,946	1,007,388,129
11		Average Marginal Cost (¢/kWh)	1.998	2.106	2.172	2.103	2.096
12							
13	On-Peak Period	Marginal Fuel Cost Weighting Multiplier					1.508
14	Off-Peak Period	Marginal Fuel Cost Weighting Multiplier					0.933
15	Average	Marginal Fuel Cost Weighting Multiplier					1.000
16							

ESTIMATED FOR THE PERIOD OF: JANUARY 2021 THROUGH DECEMBER 2021

(1)	(2)	(3)	(4)	(5)	(6)
Line No.	GROUPS	RATE SCHEDULE	JANUARY - DECEMBER		
			Average Factor	Fuel Recovery Loss Multiplier	Fuel Recovery Factor
1	A	RS-1 first 1,000 kWh	2.444	1.00226	2.123
2	A	RS-1 all additional kWh	2.444	1.00226	3.123
3					
4	A	GS-1, SL-2, GSCU-1, WIES-1	2.444	1.00226	2.449
5					
6	A-1	SL-1, OL-1, PL-1 (1)	2.352	1.00226	2.357
7					
8	B	GSD-1	2.444	1.00220	2.449
9					
10	C	GSLD-1, CS-1	2.444	1.00164	2.448
11					
12	D	GSLD-2, CS-2, OS-2, MET	2.444	0.99483	2.431
13					
14	E	GSLD-3, CS-3	2.444	0.97357	2.379
15					
16	A	GST-1 On-Peak	2.896	1.00226	2.903
17	A	GST-1 Off-Peak	2.248	1.00226	2.253
18					
19	A	RTR-1 On-Peak			0.454
20		RTR-1 Off-Peak			(0.196)
21					
22	B	GSDT-1, CILC-1(G), HLFT-1 (21-499 kW) On-Peak	2.896	1.00220	2.902
23	B	GSDT-1, CILC-1(G), HLFT-1 (21-499 kW) Off-Peak	2.248	1.00220	2.253
24					
25	C	GSLDT-1, CST-1, HLFT-2 (500-1,999 kW) On-Peak	2.896	1.00164	2.901
26	C	GSLDT-1, CST-1, HLFT-2 (500-1,999 kW) Off-Peak	2.248	1.00164	2.252
27					
28	D	GSLDT-2, CST-2, HLFT-3 (2,000+ kW) On-Peak	2.896	0.99518	2.882
29	D	GSLDT-2, CST-2, HLFT-3 (2,000+ kW) Off-Peak	2.248	0.99518	2.237
30					
31	E	GSLDT-3, CST-3, CILC-1(T), ISST-1(T) On-Peak	2.896	0.97357	2.819
32	E	GSLDT-3, CST-3, CILC-1(T), ISST-1(T) Off-Peak	2.248	0.97357	2.189
33					
34	F	CILC-1(D), ISST-1(D) On-Peak	2.896	0.99485	2.881
35		CILC-1(D), ISST-1(D) Off-Peak	2.248	0.99485	2.236
36					
37	(1) WEIGHTED AVERAGE 16% ON-PEAK AND 84% OFF-PEAK				
38					
39		Note: Totals may not add due to rounding.			

ESTIMATED FOR THE PERIOD OF: JANUARY 2021 THROUGH DECEMBER 2021

OFF PEAK: ALL OTHER HOURS

(1)	(2)	(3)	(4)	(5)	(6)
			JUNE - SEPTEMBER		
Line No.	GROUPS	RATE SCHEDULE	Average Factor	Fuel Recovery Loss Multiplier	Fuel Recovery Factor
1	B	GSD(T)-1 On-Peak	3.685	1.00220	3.693
2		GSD(T)-1 Off-Peak	2.280	1.00220	2.285
3					
4	C	GSLD(T)-1 On-Peak	3.685	1.00164	3.691
5		GSLD(T)-1 Off-Peak	2.280	1.00164	2.284
6					
7	D	GSLD(T)-2 On-Peak	3.685	0.99518	3.667
8		GSLD(T)-2 Off-Peak	2.280	0.99518	2.269
9					
10		Note: Totals may not add due to rounding.			

ESTIMATED FOR THE PERIOD OF: JANUARY 2021 THROUGH DECEMBER 2021

Line No.	Rate Class/Voltage Level	Delivered MWH Sales	Expansion Factor	Delivered Energy at Generation	Delivered Efficiency	Losses	Fuel Cost Recovery Multiplier
1	**RS(T)-1**						
2	**Secondary**	59,683,662	1.04682	62,477,801	0.95528	2,794,139	
3	TOTAL	59,683,662	1.04682	62,477,801	0.95528	2,794,139	1.00226
4							
5	**CILC-1D**						
6	**Primary**	1,092,592	1.02815	1,123,353	0.97262	30,761	
7	**Secondary**	1,541,192	1.04682	1,613,345	0.95528	72,152	
8	TOTAL	2,633,784	1.03907	2,736,697	0.96240	102,913	0.99485
9							
10	**CILC-1G**						
11	**Primary**	1,896	1.02815	1,950	0.97262	53	
12	**Secondary**	102,218	1.04682	107,003	0.95528	4,785	
13	TOTAL	104,114	1.04648	108,953	0.95559	4,839	1.00193
14							
15	**CILC-1T**						
16	**Transmission**	1,469,473	1.01686	1,494,244	0.98342	24,770	
17	TOTAL	1,469,473	1.01686	1,494,244	0.98342	24,770	0.97357
18							
19	**GS(T)-1**						
20	**Secondary**	6,501,222	1.04682	6,805,582	0.95528	304,360	
21	TOTAL	6,501,222	1.04682	6,805,582	0.95528	304,360	1.00226
22							
23	**GSCU-1**						
24	**Secondary**	77,508	1.04682	81,137	0.95528	3,629	
25	TOTAL	77,508	1.04682	81,137	0.95528	3,629	1.00226
26							
27	**GSD(T)-1**						
28	**Primary**	88,712	1.02815	91,210	0.97262	2,498	
29	**Secondary**	27,229,875	1.04682	28,504,664	0.95528	1,274,789	
30	TOTAL	27,318,587	1.04676	28,595,873	0.95533	1,277,286	1.00220
31							
32	**GSLD(T)-1**						
33	**Primary**	349,819	1.02815	359,668	0.97262	9,849	
34	**Secondary**	9,844,535	1.04682	10,305,415	0.95528	460,880	
35	TOTAL	10,194,354	1.04618	10,665,083	0.95586	470,729	1.00164
36							
37	**GSLD(T)-2**						
38	**Primary**	1,069,653	1.02815	1,099,768	0.97262	30,115	
39	**Secondary**	1,628,886	1.04682	1,705,144	0.95528	76,258	
40	TOTAL	2,698,539	1.03942	2,804,912	0.96208	106,373	0.99518
41							
42	**GSLD(T)-3**						
43	**Transmission**	259,045	1.01686	263,412	0.98342	4,367	
44	TOTAL	259,045	1.01686	263,412	0.98342	4,367	0.97357
45							
46	**MET**						
47	**Primary**	80,265	1.02815	82,525	0.97262	2,260	
48	TOTAL	80,265	1.02815	82,525	0.97262	2,260	0.98439
49							
50	**OL-1**						
51	**Secondary**	92,361	1.04682	96,685	0.95528	4,324	
52	TOTAL	92,361	1.04682	96,685	0.95528	4,324	1.00226
53							
54	**OS-2**						
55	**Primary**	9,159	1.02815	9,417	0.97262	258	
56	TOTAL	9,159	1.02815	9,417	0.97262	258	0.98439
57							

ESTIMATED FOR THE PERIOD OF: JANUARY 2021 THROUGH DECEMBER 2021

Line No.	Rate Class/Voltage Level	Delivered MWH Sales	Expansion Factor	Delivered Energy at Generation	Delivered Efficiency	Losses	Fuel Cost Recovery Multiplier
1	**SL-1**						
2	**Secondary**	474,425	1.04682	496,636	0.95528	22,211	
3	TOTAL	474,425	1.04682	496,636	0.95528	22,211	1.00226
4							
5	**SL-2**						
6	**Secondary**	26,412	1.04682	27,648	0.95528	1,236	
7	TOTAL	26,412	1.04682	27,648	0.95528	1,236	1.00226
8							
9	**SL-1M**						
10	**Secondary**	8,728	1.04682	9,136	0.95528	409	
11	TOTAL	8,728	1.04682	9,136	0.95528	409	1.00226
12							
13	**SL-2M**						
14	**Secondary**	1,664	1.04682	1,742	0.95528	78	
15	TOTAL	1,664	1.04682	1,742	0.95528	78	1.00226
16							
17	**SST-DST**						
18	**Primary**	1,006	1.02815	1,035	0.97262	28	
19	**Secondary**	842	1.04682	882	0.95528	39	
20	TOTAL	1,849	1.03666	1,916	0.96464	68	0.99253
21							
22	**SST-TST**						
23	**Transmission**	92,717	1.01686	94,280	0.98342	1,563	
24	TOTAL	92,717	1.01686	94,280	0.98342	1,563	0.97357
25							
26	**TOTAL FPSC**						
27	TOTAL	111,727,869	1.04588	116,853,679	0.95613	5,125,810	1.00136
28							
29	**FKEC**						
30	**Transmission**	800,070	1.01686	813,557	0.98342	13,486	
31	TOTAL	800,070	1.01686	813,557	0.98342	13,486	0.97357
32							
33	**FPUC (INT)**						
34	**Transmission**	101,010	1.01686	102,713	0.98342	1,703	
35	TOTAL	101,010	1.01686	102,713	0.98342	1,703	0.97357
36							
37	**FPUC (PEAK)**						
38	**Transmission**	53,077	1.01686	53,972	0.98342	895	
39	TOTAL	53,077	1.01686	53,972	0.98342	895	0.97357
40							
41	**Homestead**						
42	**Transmission**	159	1.01686	162	0.98342	3	
43	TOTAL	159	1.01686	162	0.98342	3	0.97357
44							
45	**LCEC**						
46	**Transmission**	4,356,471	1.01686	4,429,906	0.98342	73,435	
47	TOTAL	4,356,471	1.01686	4,429,906	0.98342	73,435	0.97357
48							
49	**MOORE HAVEN**						
50	**Transmission**	28	1.01686	28	0.98342	0	
51	TOTAL	28	1.01686	28	0.98342	0	0.97357
52							
53	**NEW SMRYNA BCH (PEAK)**						
54	**Transmission**	159	1.01686	162	0.98342	3	
55	TOTAL	159	1.01686	162	0.98342	3	0.97357
56							
57							

ESTIMATED FOR THE PERIOD OF: JANUARY 2021 THROUGH DECEMBER 2021

Line No.	Rate Class/Voltage Level	Delivered MWH Sales	Expansion Factor	Delivered Energy at Generation	Delivered Efficiency	Losses	Fuel Cost Recovery Multiplier
1	**New Smryna Beach**						
2	**Transmission**	357	1.01686	363	0.98342	6	
3	TOTAL	357	1.01686	363	0.98342	6	0.97357
4							
5	**Quincy**						
6	**Transmission**	151	1.01686	153	0.98342	3	
7	TOTAL	151	1.01686	153	0.98342	3	0.97357
8							
9	**SEMINOLE**						
10	**Transmission**	422,964	1.01686	430,093	0.98342	7,130	
11	TOTAL	422,964	1.01686	430,093	0.98342	7,130	0.97357
12							
13	**WAUCHULA**						
14	**Transmission**	91	1.01686	93	0.98342	2	
15	TOTAL	91	1.01686	93	0.98342	2	0.97357
16							
17	**TOTAL FERC**						
18	TOTAL	5,746,976	1.01686	5,843,851	0.98342	96,874	0.97357
19							
20	**Total Company**						
21	TOTAL	117,474,845	1.04446	122,697,529	0.95743	5,222,684	
22							
23	**Company Use**						
24	TOTAL	135,314	1.04682	141,649	0.95528	6,335	
25							
26	**Total FPL**						
27	TOTAL	117,610,159	1.04446	122,839,178	0.95743	5,229,019	
28							
29	**HOMESTEAD (INT)**						
30	**Transmission**	405	1.01686	412	0.98342	7	
31	TOTAL	405	1.01686	412	0.98342	7	0.97357
32							
33	**NEW SMYRNA BCH (INT)**						
34	**Transmission**	12,034	1.01686	12,237	0.98342	203	
35	TOTAL	12,034	1.01686	12,237	0.98342	203	0.97357
36							
37							
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ESTIMATED FOR THE PERIOD OF: JANUARY 2021 THROUGH DECEMBER 2021

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
Line No.	RATE CLASS GROUPS	Delivered MWH Sales	Expansion Factor	Delivered Energy at Generation	Delivered Efficiency	Losses	Fuel Cost Recovery Multiplier
1	GSD1/GSDT1/HLFT1	27,318,587	1.046755	28,595,873	0.955333	1,277,286	1.00220
2	GSLD1/GSLDT1/CS1/CST1/HLFT2	10,194,354	1.046175	10,665,083	0.955863	470,729	1.00164
3	GSLD2/GSLDT2/CS2/CST2/HLFT3	2,698,539	1.039419	2,804,912	0.962076	106,373	0.99517
4	GSLD3/GSLDT3/CS3/CST3	259,045	1.016857	263,412	0.983423	4,367	0.97357
5	CILC D/CILC G	2,737,898	1.039356	2,845,650	0.962135	107,752	0.99511
6	OL1/SL1/SL1M/PL1	575,514	1.046816	602,457	0.955278	26,943	1.00225
7	SL2/SL2M/GSCU1	105,584	1.046816	110,527	0.955278	4,943	1.00225
8	GSD-1/GSDT-1/HLFT-1/SDTR-1/CILC-1G	27,422,701	1.046754	28,704,826	0.955334	1,282,125	1.00220
9	GSLDT-2/CS-2/HLFT-3/SDTR-3/OS-2/MET	2,787,963	1.039057	2,896,853	0.962411	108,890	0.99483
10	GSLD-3/GSLDT-3/CS-3/CST-3/CILC-1T	1,728,519	1.016857	1,757,656	0.983423	29,137	0.97357

ESTIMATED FOR THE PERIOD OF: JANUARY 2021 THROUGH DECEMBER 2021

(1)	(2)	(3)	(4)	(5)	(6)
Line No.		RS-1 Standard	Proposed Inverted Fuel Factors	Target Fuel Revenues	Rounded
1	First 1000 KWH	40,230,591,319	0.021226	$853,914,913	2.123
2	All Additional KWH	19,498,482,245	0.031226	$608,850,098	3.123
3	Total KWH	59,729,073,564		$1,462,765,012	
4					
5	Avg Fuel Factor	2.444			
6	RS-1 Loss Multiplier	1.00226			
7	Average Fuel Factor	2.449			
8					
9	Target Fuel Revenues	$1,462,765,012			

ESTIMATED FOR THE PERIOD OF: JANUARY 2021 THROUGH DECEMBER 2021

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
Line No.	Line	Jan - 2021	Feb - 2021	Mar - 2021	Apr - 2021	May - 2021	Jun - 2021	Jul - 2021	Aug - 2021	Sep - 2021	Oct - 2021	Nov - 2021	Dec - 2021	2021
1	Fuel Cost of System Net Generation (E3)	217,911,217	199,513,626	214,383,826	213,708,021	234,122,553	241,358,695	260,271,868	267,522,496	252,817,668	239,627,588	202,367,365	211,393,984	2,754,998,906
2	Fuel Cost of Stratified Sales	(1,608,207)	(1,245,833)	(1,471,751)	(2,276,045)	(2,653,728)	(3,196,388)	(638,532)	(582,161)	(481,964)	(267,135)	(208,966)	(192,675)	(14,823,385)
3	Rail Car Lease (Cedar Bay/Indiantown)	165,557	165,557	162,884	165,557	164,666	165,557	164,666	165,557	165,557	164,666	165,557	164,666	1,980,447
4	Fuel Cost of Power Sold (Per E6)	(8,996,093)	(8,618,720)	(5,211,030)	(3,841,876)	(4,198,807)	(3,190,586)	(3,352,407)	(3,240,984)	(2,986,979)	(2,819,325)	(3,755,347)	(4,917,904)	(55,130,059)
5	Gains from Off-System Sales (Per E6)	(5,678,698)	(4,229,427)	(1,921,037)	(1,641,275)	(1,926,331)	(1,401,711)	(1,413,034)	(1,319,024)	(1,250,360)	(1,055,802)	(1,452,731)	(1,982,771)	(25,272,200)
6	Fuel Cost of Purchased Power (Exclusive of Economy) (E7)	2,725,898	2,679,386	2,728,234	2,478,267	2,301,085	2,775,100	2,530,615	2,212,294	2,305,782	2,128,823	2,551,092	2,493,401	29,909,976
7	Energy Payments to Qualifying Facilities (Per E8)	519,164	442,266	525,407	474,586	504,676	422,762	478,873	430,892	551,230	520,724	493,763	555,509	5,919,852
8	Energy Cost of Economy Purchases (Per E9)	-	-	491,040	475,200	911,400	2,424,750	1,188,540	795,150	1,908,000	765,700	59,400	-	9,019,180
9	Total Fuel Costs & Net Power Transactions	205,038,838	188,706,854	209,687,573	209,542,434	229,225,512	239,358,179	259,230,589	265,984,220	253,028,934	239,065,240	200,220,133	207,514,210	2,706,602,716
10														
11	Incremental Personnel, Software, and Hardware Costs	38,683	34,861	38,141	36,501	39,781	36,501	38,141	39,781	34,861	39,781	38,141	36,501	451,676
12	Variable Power Plant O&M Attributable to Off-System Sales (Per E6)	291,772	271,908	159,588	124,410	133,595	90,090	90,272	92,690	79,950	70,727	124,215	159,790	1,689,006
13	Variable Power Plant O&M Avoided due to Economy Purchases (Per E9)	(0)	(0)	(13,299)	(12,870)	(24,180)	(59,475)	(28,613)	(19,143)	(46,800)	(19,143)	(2,145)	(0)	(225,667)
14	Total	$330,455	$306,769	$184,430	$148,041	$149,196	$67,116	$99,800	$113,329	$68,011	$91,365	$160,211	$196,291	$1,915,015
15														
16	Other O&M Expense	-	5,044	-	-	206,711	-	-	361,205	-	-	-	-	572,960
17														
18	ADJUSTED TOTAL FUEL & NET POWER TRANS	205,369,293	189,018,667	209,872,003	209,690,476	229,581,419	239,425,295	259,330,389	266,458,754	253,096,946	239,156,605	200,380,344	207,710,501	2,709,090,691
19														
20	System MWH Sales (Excluding Stratified Sales)	8,850,541	8,020,325	8,082,659	8,794,861	9,611,029	10,732,733	11,384,880	11,699,201	11,567,674	10,464,418	9,124,714	8,605,856	116,938,891
21														
22	Cost per KWh	2.3204	2.3567	2.5966	2.3842	2.3887	2.2308	2.2778	2.2776	2.1880	2.2854	2.1960	2.4136	2.3167
23	Jurisdictional Loss Multiplier	1.00136	1.00136	1.00136	1.00136	1.00136	1.00136	1.00136	1.00136	1.00136	1.00136	1.00136	1.00136	1.00136
24	Jurisdictional Cost	2.3236	2.3599	2.6001	2.3875	2.3920	2.2338	2.2809	2.2807	2.1909	2.2885	2.1990	2.4169	2.3198
25	True Up (cents/KWh)	.0203	.0225	.0223	.0205	.0187	.0168	.0158	.0154	.0155	.0172	.0199	.0209	.0185
26	Total (cents/KWh)	2.3439	2.3824	2.6224	2.4080	2.4107	2.2506	2.2967	2.2961	2.2064	2.3057	2.2189	2.4378	2.3383
27	Revenue Tax Factor	.0017	.0017	.0019	.0017	.0017	.0016	.0017	.0017	.0016	.0017	.0016	.0018	.0017
28	Recovery Factor adjusted for Taxes (cents/KWh)	2.3456	2.3841	2.6243	2.4097	2.4124	2.2522	2.2984	2.2978	2.2080	2.3074	2.2205	2.4396	2.3400
29	GPIF (cents/KWh)	.0080	.0088	.0087	.0080	.0074	.0066	.0062	.0061	.0061	.0068	.0078	.0082	.0073
30	Jurisdictional Incentive Mechanism - FPL Portion	.0085	.0095	.0094	.0086	.0079	.0071	.0067	.0065	.0065	.0073	.0084	.0088	.0078
31	Solar Together - Subscription Credit (cents/KWH)	.0572	.0663	.0855	.0953	.1044	.0851	.0973	.0899	.0850	.0966	.0991	.0939	.0885
32	Recovery Factor Including GPIF and Incentive	2.4193	2.4687	2.7279	2.5216	2.5321	2.3510	2.4086	2.4003	2.3056	2.4181	2.3358	2.5505	2.4436
33														
34	Recovery Factor Rounded to .001 (¢/KWh)	2.419	2.469	2.728	2.522	2.532	2.351	2.409	2.400	2.306	2.418	2.336	2.551	2.444
35														

ESTIMATED FOR THE PERIOD OF: JANUARY 2021 THROUGH DECEMBER 2021

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
Line No.	Line	Jan - 2021	Feb - 2021	Mar - 2021	Apr - 2021	May - 2021	Jun - 2021	Jul - 2021	Aug - 2021	Sep - 2021	Oct - 2021	Nov - 2021	Dec - 2021	2021
1	**Fuel Cost of System Net Generation ($)**													
2	Heavy Oil	-	209,793	-	31,804	-	740,763	872,595	1,694,222	1,065,206	370,290	-	-	4,984,674
3	Light Oil	-	305,702	-	-	-	-	440,732	563,777	202,610	-	-	-	1,512,821
4	Coal	5,246,769	4,835,208	5,362,558	5,153,610	5,219,720	5,174,604	5,374,318	5,570,548	5,329,017	5,478,787	5,084,560	5,150,603	62,980,302
5	Gas	199,310,585	182,101,368	195,667,406	198,055,629	217,129,213	222,619,898	240,333,344	246,801,186	236,083,281	222,753,367	184,840,302	192,748,291	2,538,443,871
6	Nuclear	13,353,863	12,061,554	13,353,863	10,466,978	11,773,620	12,823,430	13,250,878	12,892,762	10,137,554	11,025,143	12,442,503	13,495,090	147,077,238
7	**Total Fuel Cost of System Net Generation ($)**	217,911,217	199,513,626	214,383,826	213,708,021	234,122,553	241,358,695	260,271,868	267,522,496	252,817,668	239,627,588	202,367,365	211,393,984	2,754,998,906
8														
9	**System Net Generation (MWh)**													
10	Heavy Oil	-	1,423	-	191	-	5,889	7,054	13,997	8,713	2,965	-	-	40,231
11	Light Oil	-	1,461	-	-	-	-	2,020	2,880	1,032	-	-	-	7,393
12	Coal	180,619	167,279	185,870	178,413	180,562	179,595	186,128	193,251	184,198	189,076	174,225	175,262	2,174,478
13	Gas	6,008,376	5,500,151	6,042,037	6,875,824	7,961,164	8,145,429	8,887,874	9,167,999	8,794,012	7,853,321	5,973,395	5,954,896	87,164,479
14	Nuclear	2,603,851	2,351,866	2,603,851	1,974,218	2,239,728	2,456,261	2,538,136	2,459,518	1,866,623	2,067,994	2,399,256	2,603,851	28,165,152
15	Solar	398,370	407,254	528,351	594,343	641,545	570,736	635,119	608,085	564,065	576,410	509,227	459,520	6,493,025
16	**Total System Net Generation (MWh)**	9,191,215	8,429,434	9,360,109	9,622,989	11,022,999	11,357,910	12,256,331	12,445,730	11,418,643	10,689,766	9,056,103	9,193,529	124,044,758
17														
18	**Units of Fuel Burned (Unit)** [(1)]													
19	Heavy Oil	-	3,060	-	464	-	10,805	12,728	24,713	15,538	5,401	-	-	72,709
20	Light Oil	-	4,021	-	-	-	-	5,242	6,996	2,528	-	-	-	18,788
21	Coal	121,677	112,249	124,585	119,921	121,719	120,705	125,019	129,150	123,358	126,722	117,378	118,582	1,461,064
22	Gas	40,727,825	37,832,005	41,116,807	47,164,511	54,249,228	56,306,120	61,482,515	63,564,272	60,796,028	54,086,957	40,661,507	40,805,782	598,793,557
23	Nuclear	27,046,729	24,429,304	27,046,729	21,083,802	23,895,442	26,174,118	27,046,589	26,221,435	19,985,463	21,966,749	24,902,972	27,046,729	296,846,059
24														
25	**BTU Burned (MMBTU)**													
26	Heavy Oil	-	19,585	-	2,969	-	69,153	81,460	158,162	99,441	34,568	-	-	465,338
27	Light Oil	-	23,445	-	-	-	-	30,563	40,789	14,737	-	-	-	109,534
28	Coal	2,068,506	1,908,230	2,117,950	2,038,652	2,069,231	2,051,993	2,125,320	2,195,543	2,097,080	2,154,272	1,995,419	2,015,896	24,838,092
29	Gas	40,727,825	37,832,005	41,116,807	47,164,511	54,249,228	56,306,120	61,482,515	63,564,272	60,796,028	54,086,957	40,661,507	40,805,782	598,793,557
30	Nuclear	27,046,729	24,429,304	27,046,729	21,083,802	23,895,442	26,174,118	27,046,589	26,221,435	19,985,463	21,966,749	24,902,972	27,046,729	296,846,059
31	**Total BTU Burned (MMBTU)**	69,843,060	64,212,569	70,281,486	70,289,934	80,213,901	84,601,384	90,766,447	92,180,201	82,992,749	78,242,546	67,559,898	69,868,407	921,052,580
32														
33	**Fuel Cost per Unit ($/Unit)**													
34	Heavy Oil	-	68.5563	-	68.5559	-	68.5564	68.5564	68.5564	68.5564	68.5564	-	-	68.5564
35	Light Oil	-	76.0180	-	-	-	-	84.0712	80.5810	80.1529	-	-	-	80.5206
36	Coal	43.1205	43.0758	43.0433	42.9751	42.8832	42.8697	42.9881	43.1325	43.1997	43.2347	43.3180	43.4349	43.1058
37	Gas	4.8937	4.8134	4.7588	4.1993	4.0024	3.9537	3.9090	3.8827	3.8832	4.1184	4.5458	4.7236	4.2393
38	Nuclear	.4937	.4937	.4937	.4964	.4927	.4899	.4899	.4917	.5072	.5019	.4996	.4990	.4955
39														
40	**Generation Mix (%)**													
41	Heavy Oil	N/A	0.02%	N/A	0.00%	N/A	0.05%	0.06%	0.11%	0.08%	0.03%	N/A	N/A	0.03%
42	Light Oil		0.02%	N/A	N/A	N/A	N/A	0.02%	0.02%	0.01%	N/A	N/A	N/A	0.01%
43	Coal	1.97%	1.98%	1.99%	1.85%	1.64%	1.58%	1.52%	1.55%	1.61%	1.77%	1.92%	1.91%	1.75%
44	Gas	65.37%	65.25%	64.55%	71.45%	72.22%	71.72%	72.52%	73.66%	77.01%	73.47%	65.96%	64.77%	70.27%
45	Nuclear	28.33%	27.90%	27.82%	20.52%	20.32%	21.63%	20.71%	19.76%	16.35%	19.35%	26.49%	28.32%	22.71%
46	Solar	4.33%	4.83%	5.64%	6.18%	5.82%	5.03%	5.18%	4.89%	4.94%	5.39%	5.62%	5.00%	5.23%
47														
48	**Fuel Cost per MMBTU ($/MMBTU)**													
49	Heavy Oil	-	10.7119	-	10.7119	-	10.7119	10.7119	10.7119	10.7119	10.7119	-	-	10.7119
50	Light Oil	-	13.0391	-	-	-	-	14.4205	13.8218	13.7484	-	-	-	13.8114

ESTIMATED FOR THE PERIOD OF: JANUARY 2021 THROUGH DECEMBER 2021

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
Line No.	Line	Jan - 2021	Feb - 2021	Mar - 2021	Apr - 2021	May - 2021	Jun - 2021	Jul - 2021	Aug - 2021	Sep - 2021	Oct - 2021	Nov - 2021	Dec - 2021	2021
51	Coal	2.5365	2.5339	2.5320	2.5279	2.5225	2.5217	2.5287	2.5372	2.5412	2.5432	2.5481	2.5550	2.5356
52	Gas	4.8937	4.8134	4.7588	4.1993	4.0024	3.9537	3.9090	3.8827	3.8832	4.1184	4.5458	4.7236	4.2393
53	Nuclear	0.4937	0.4937	0.4937	0.4964	0.4927	0.4899	0.4899	0.4917	0.5072	0.5019	0.4996	0.4990	0.4955
54														
55	**BTU Burned per KWH (BTU/KWH)**													
56	Heavy Oil	-	13,768	-	15,546	-	11,743	11,548	11,300	11,414	11,660	-	-	11,567
57	Light Oil	-	16,047	-	-	-	-	15,130	14,163	14,280	-	-	-	14,816
58	Coal	11,452	11,407	11,395	11,427	11,460	11,426	11,419	11,361	11,385	11,394	11,453	11,502	11,423
59	Gas	6,779	6,878	6,805	6,859	6,814	6,913	6,918	6,933	6,913	6,887	6,807	6,852	6,870
60	Nuclear	10,387	10,387	10,387	10,680	10,669	10,656	10,656	10,661	10,707	10,622	10,379	10,387	10,539
61														
62	**Generated Fuel Cost per KWH (cents/KWH)**													
63	Heavy Oil	-	14.7482	-	16.6529	-	12.5787	12.3707	12.1041	12.2261	12.4902	-	-	12.3903
64	Light Oil	-	20.9242	-	-	-	-	21.8184	19.5756	19.6327	-	-	-	20.4629
65	Coal	2.9049	2.8905	2.8851	2.8886	2.8908	2.8813	2.8874	2.8825	2.8931	2.8977	2.9184	2.9388	2.8963
66	Gas	3.3172	3.3108	3.2384	2.8805	2.7274	2.7331	2.7041	2.6920	2.6846	2.8364	3.0944	3.2368	2.9122
67	Nuclear	0.5129	0.5129	0.5129	0.5302	0.5257	0.5221	0.5221	0.5242	0.5431	0.5331	0.5186	0.5183	0.5222
68	**Total Generated Fuel Cost per KWH (cents/KWH)**	2.3709	2.3669	2.2904	2.2208	2.1239	2.1250	2.1236	2.1495	2.2141	2.2417	2.2346	2.2994	2.2210
69														
70														
71														
72														
73														
74														
75														
76														
77	(1) Fuel Units: Heavy Oil - BBLS, Light Oil - BBLS, Coal - TONS, Gas - MMBTU, Nuclear - OTHER													
78														
79	Note: Totals may not add due to rounding.													

ESTIMATED FOR THE PERIOD OF: JANUARY 2021 THROUGH DECEMBER 2021

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.	PLANT UNIT	Net Capability (MW)	Net Generation (MWH)	Capacity Factor	Equivalent Availability Factor	Net Output Factor	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost ($)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel ($/Unit)
1	**Jan - 2021**												
2	Babcock PV Solar												
3	Solar		12,457					N/A	N/A	N/A	N/A	N/A	N/A
4	Plant Unit Info	74.5	12,457	22.5%	N/A	22.5%	N/A						
5	Babcock Preserve PV Solar												
6	Solar		13,246					N/A	N/A	N/A	N/A	N/A	N/A
7	Plant Unit Info	74.5	13,246	23.9%	N/A	23.9%	N/A						
8	Barefoot PV Solar												
9	Solar		12,659					N/A	N/A	N/A	N/A	N/A	N/A
10	Plant Unit Info	74.5	12,659	22.8%	N/A	22.8%	N/A						
11	Blue Cypress PV Solar												
12	Solar		13,175					N/A	N/A	N/A	N/A	N/A	N/A
13	Plant Unit Info	74.5	13,175	23.8%	N/A	23.8%	N/A						
14	Blue Heron PV Solar												
15	Solar		13,246					N/A	N/A	N/A	N/A	N/A	N/A
16	Plant Unit Info	74.5	13,246	23.9%	N/A	23.9%	N/A						
17	CCEC 3												
18	Light Oil		0					0	0	0	0	0.00	0.00
19	Gas		444,127				6,759	3,002,067	1,000,000	3,002,067	14,736,966	3.32	4.91
20	Plant Unit Info	1,326.0	444,127	45.0%	93.4%	45.0%	6,759			3,002,067	14,736,966	3.32	
21	Cattle Ranch PV Solar												
22	Solar		11,618					N/A	N/A	N/A	N/A	N/A	N/A
23	Plant Unit Info	74.5	11,618	21.0%	N/A	21.0%	N/A						
24	Citrus PV Solar												
25	Solar		12,537					N/A	N/A	N/A	N/A	N/A	N/A
26	Plant Unit Info	74.5	12,537	22.6%	N/A	22.6%	N/A						
27	Coral Farms PV Solar												
28	Solar		13,003					N/A	N/A	N/A	N/A	N/A	N/A
29	Plant Unit Info	74.5	13,003	23.5%	N/A	23.5%	N/A						
30	Desoto Solar												
31	Solar		3,151					N/A	N/A	N/A	N/A	N/A	N/A
32	Plant Unit Info	25.0	3,151	16.9%	N/A	16.9%	N/A						
33	Discovery PV Solar												
34	Solar		0					N/A	N/A	N/A	N/A	N/A	N/A
35	Plant Unit Info	0.0	0	N/A	N/A	N/A	N/A						
36	Egret PV Solar												
37	Solar		11,270					N/A	N/A	N/A	N/A	N/A	N/A
38	Plant Unit Info	74.5	11,270	20.3%	N/A	20.3%	N/A						
39	Fort Drum PV Solar												
40	Solar		0					N/A	N/A	N/A	N/A	N/A	N/A
41	Plant Unit Info	0.0	0	N/A	N/A	N/A	N/A						
42	Fort Myers 2												
43	Gas		571,335				7,412	4,234,700	1,000,000	4,234,700	20,790,455	3.64	4.91

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(1) Line No.	(2) PLANT UNIT	(3) Net Capability (MW)	(4) Net Generation (MWH)	(5) Capacity Factor	(6) Equivalent Availability Factor	(7) Net Output Factor	(8) Avg Net Heat Rate (BTU/KWH)	(9) Fuel Burned (Units)	(10) Fuel Heat Value (BTU/Unit)	(11) Fuel Burned (MMBTU)	(12) As Burned Fuel Cost ($)	(13) Fuel Cost per KWH (cents/KWH)	(14) Cost of Fuel ($/Unit)
1	Plant Unit Info	1,770.0	571,335	43.4%	93.8%	43.4%	7,412			4,234,700	20,790,455	3.64	
2	Fort Myers 3A												
3	Light Oil		0					0	0	0	0	0.00	0.00
4	Gas		0					0	0	0	0	0.00	0.00
5	Plant Unit Info	189.0	0	N/A	93.7%	N/A	N/A						
6	Fort Myers 3B												
7	Light Oil		0					0	0	0	0	0.00	0.00
8	Gas		0					0	0	0	0	0.00	0.00
9	Plant Unit Info	193.0	0	N/A	93.7%	N/A	N/A						
10	Fort Myers 3C												
11	Light Oil		0					0	0	0	0	0.00	0.00
12	Gas		0					0	0	0	0	0.00	0.00
13	Plant Unit Info	221.0	0	N/A	93.7%	N/A	N/A						
14	Fort Myers 3D												
15	Light Oil		0					0	0	0	0	0.00	0.00
16	Gas		0					0	0	0	0	0.00	0.00
17	Plant Unit Info	221.0	0	N/A	93.7%	N/A	N/A						
18	Echo River PV Solar												
19	Solar		12,535					N/A	N/A	N/A	N/A	N/A	N/A
20	Plant Unit Info	74.5	12,535	22.6%	N/A	22.6%	N/A						
21	Hammock PV Solar												
22	Solar		13,687					N/A	N/A	N/A	N/A	N/A	N/A
23	Plant Unit Info	74.5	13,687	24.7%	N/A	24.7%	N/A						
24	Hibiscus PV Solar												
25	Solar		12,074					N/A	N/A	N/A	N/A	N/A	N/A
26	Plant Unit Info	74.5	12,074	21.8%	N/A	21.8%	N/A						
27	Horizon PV Solar												
28	Solar		13,108					N/A	N/A	N/A	N/A	N/A	N/A
29	Plant Unit Info	74.5	13,108	23.7%	N/A	23.7%	N/A						
30	Indian River PV Solar												
31	Solar		13,165					N/A	N/A	N/A	N/A	N/A	N/A
32	Plant Unit Info	74.5	13,165	23.8%	N/A	23.8%	N/A						
33	Indiantown												
34	Plant Unit Info	0.0	0	N/A	N/A	N/A	N/A						
35	Interstate PV Solar												
36	Solar		12,665					N/A	N/A	N/A	N/A	N/A	N/A
37	Plant Unit Info	74.5	12,665	22.9%	N/A	22.9%	N/A						
38	Lakeside PV Solar												
39	Solar		13,079					N/A	N/A	N/A	N/A	N/A	N/A
40	Plant Unit Info	74.5	13,079	23.6%	N/A	23.6%	N/A						
41	Lauderdale 6A												
42	Light Oil		0					0	0	0	0	0.00	0.00
43	Gas		0					0	0	0	0	0.00	0.00

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(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.	PLANT UNIT	Net Capability (MW)	Net Generation (MWH)	Capacity Factor	Equivalent Availability Factor	Net Output Factor	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost ($)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel ($/Unit)
1	Plant Unit Info	218.0	0	N/A	94.0%	N/A	N/A						
2	Lauderdale 6B												
3	Light Oil		0					0	0	0	0	0.00	0.00
4	Gas		0					0	0	0	0	0.00	0.00
5	Plant Unit Info	218.0	0	N/A	71.4%	N/A	N/A						
6	Lauderdale 6C												
7	Light Oil		0					0	0	0	0	0.00	0.00
8	Gas		0					0	0	0	0	0.00	0.00
9	Plant Unit Info	218.0	0	N/A	94.0%	N/A	N/A						
10	Lauderdale 6D												
11	Light Oil		0					0	0	0	0	0.00	0.00
12	Gas		0					0	0	0	0	0.00	0.00
13	Plant Unit Info	218.0	0	N/A	71.4%	N/A	N/A						
14	Lauderdale 6E												
15	Light Oil		0					0	0	0	0	0.00	0.00
16	Gas		0					0	0	0	0	0.00	0.00
17	Plant Unit Info	218.0	0	N/A	94.0%	N/A	N/A						
18	Loggerhead PV Solar												
19	Solar		13,304					N/A	N/A	N/A	N/A	N/A	N/A
20	Plant Unit Info	74.5	13,304	24.0%	N/A	24.0%	N/A						
21	Magnolia PV Solar												
22	Solar		11,352					N/A	N/A	N/A	N/A	N/A	N/A
23	Plant Unit Info	74.5	11,352	20.5%	N/A	20.5%	N/A						
24	Manatee 1												
25	Heavy Oil		-					0	0	0	0	0.00	0.00
26	Gas		0					0	0	0	0	0.00	0.00
27	Plant Unit Info	797.0	0	N/A	94.1%	N/A	N/A						
28	Manatee 2												
29	Heavy Oil		-					0	0	0	0	0.00	0.00
30	Gas		0					0	0	0	0	0.00	0.00
31	Plant Unit Info	797.0	0	N/A	94.1%	N/A	N/A						
32	Manatee 3												
33	Gas		34,901				8,316	290,224	1,000,000	290,224	1,414,677	4.05	4.87
34	Plant Unit Info	1,254.0	34,901	3.7%	93.9%	3.7%	8,316			290,224	1,414,677	4.05	
35	Manatee PV Solar												
36	Solar		12,567					N/A	N/A	N/A	N/A	N/A	N/A
37	Plant Unit Info	74.5	12,567	22.7%	N/A	22.7%	N/A						
38	Martin 3												
39	Gas		127,816				7,721	986,809	1,000,000	986,809	4,809,783	3.76	4.87
40	Plant Unit Info	492.0	127,816	34.9%	93.9%	34.9%	7,721			986,809	4,809,783	3.76	
41	Martin 4												
42	Gas		2,622				9,489	24,879	1,000,000	24,879	121,272	4.63	4.87
43	Plant Unit Info	492.0	2,622	0.7%	93.9%	0.7%	9,489			24,879	121,272	4.63	

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(1) Line No.	(2) PLANT UNIT	(3) Net Capability (MW)	(4) Net Generation (MWH)	(5) Capacity Factor	(6) Equivalent Availability Factor	(7) Net Output Factor	(8) Avg Net Heat Rate (BTU/KWH)	(9) Fuel Burned (Units)	(10) Fuel Heat Value (BTU/Unit)	(11) Fuel Burned (MMBTU)	(12) As Burned Fuel Cost ($)	(13) Fuel Cost per KWH (cents/KWH)	(14) Cost of Fuel ($/Unit)
1	Martin 8 Solar												
2	Solar		7,409					N/A	N/A	N/A	N/A	N/A	N/A
3	Plant Unit Info	75.0	7,409	13.3%	N/A	13.3%	N/A						
4	Martin 8												
5	Light Oil		0					0	0	0	0	0.00	0.00
6	Gas		16,224				8,800	142,763	1,000,000	142,763	696,097	4.29	4.88
7	Plant Unit Info	1,258.0	16,224	1.7%	93.5%	1.7%	8,800			142,763	696,097	4.29	
8	Miami-Dade PV Solar												
9	Solar		13,154					N/A	N/A	N/A	N/A	N/A	N/A
10	Plant Unit Info	74.5	13,154	23.7%	N/A	23.7%	N/A						
11	Nassau PV Solar												
12	Solar		11,217					N/A	N/A	N/A	N/A	N/A	N/A
13	Plant Unit Info	74.5	11,217	20.2%	N/A	20.2%	N/A						
14	Northern Preserve PV Solar												
15	Solar		11,513					N/A	N/A	N/A	N/A	N/A	N/A
16	Plant Unit Info	74.5	11,513	20.8%	N/A	20.8%	N/A						
17	Okeechobee 1												
18	Light Oil		0					0	0	0	0	0.00	0.00
19	Gas		1,068,999				6,281	6,714,045	1,000,000	6,714,045	32,841,851	3.07	4.89
20	Plant Unit Info	1,655.1	1,068,999	86.8%	93.0%	86.8%	6,281			6,714,045	32,841,851	3.07	
21	Okeechobee PV Solar												
22	Solar		12,645					N/A	N/A	N/A	N/A	N/A	N/A
23	Plant Unit Info	74.5	12,645	22.8%	N/A	22.8%	N/A						
24	Orange Blossom PV Solar												
25	Solar		0					N/A	N/A	N/A	N/A	N/A	N/A
26	Plant Unit Info	0.0	0	N/A	N/A	N/A	N/A						
27	Palm Bay PV Solar												
28	Solar		0					N/A	N/A	N/A	N/A	N/A	N/A
29	Plant Unit Info	0.0	0	N/A	N/A	N/A	N/A						
30	PEEC												
31	Gas		844,647				6,347	5,361,011	1,000,000	5,361,011	26,320,196	3.12	4.91
32	Plant Unit Info	1,283.0	844,647	88.5%	93.0%	88.5%	6,347			5,361,011	26,320,196	3.12	
33	Pelican PV Solar												
34	Solar		0					N/A	N/A	N/A	N/A	N/A	N/A
35	Plant Unit Info	0.0	0	N/A	N/A	N/A	N/A						
36	Pioneer Trail PV Solar												
37	Solar		12,138					N/A	N/A	N/A	N/A	N/A	N/A
38	Plant Unit Info	74.5	12,138	21.9%	N/A	21.9%	N/A						
39	Riviera 5												
40	Light Oil		0					0	0	0	0	0.00	0.00
41	Gas		576,410				6,714	3,870,085	1,000,000	3,870,085	18,930,579	3.28	4.89
42	Plant Unit Info	1,326.0	576,410	58.4%	93.4%	58.4%	6,714			3,870,085	18,930,579	3.28	
43	Rodeo PV Solar												

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(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.	PLANT UNIT	Net Capability (MW)	Net Generation (MWH)	Capacity Factor	Equivalent Availability Factor	Net Output Factor	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost ($)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel ($/Unit)
1	Solar		0					N/A	N/A	N/A	N/A	N/A	N/A
2	Plant Unit Info	0.0	0	N/A	N/A	N/A	N/A						
3	Sabal Palm PV Solar												
4	Solar		0					N/A	N/A	N/A	N/A	N/A	N/A
5	Plant Unit Info	0.0	0	N/A	N/A	N/A	N/A						
6	Sanford 4												
7	Gas		5,411				8,970	48,537	1,000,000	48,537	238,951	4.42	4.92
8	Plant Unit Info	1,192.0	5,411	0.6%	94.1%	0.6%	8,970			48,537	238,951	4.42	
9	Sanford 5												
10	Gas		326,909				7,275	2,378,187	1,000,000	2,378,187	11,676,046	3.57	4.91
11	Plant Unit Info	1,192.0	326,909	36.9%	94.1%	36.9%	7,275			2,378,187	11,676,046	3.57	
12	Scherer 4												
13	Coal		180,619				11,452	121,677	17,000,000	2,068,506	5,246,769	2.90	43.12
14	Plant Unit Info	626.0	180,619	38.8%	92.2%	38.8%	11,452			2,068,506	5,246,769	2.90	
15	Southfork PV Solar												
16	Solar		13,849					N/A	N/A	N/A	N/A	N/A	N/A
17	Plant Unit Info	74.5	13,849	25.0%	N/A	25.0%	N/A						
18	Space Coast												
19	Solar		1,280					N/A	N/A	N/A	N/A	N/A	N/A
20	Plant Unit Info	10.0	1,280	17.2%	N/A	17.2%	N/A						
21	St Lucie 1												
22	Nuclear		727,591				10,328	7,514,787	1,000,000	7,514,787	3,625,884	0.50	0.48
23	Plant Unit Info	1,003.0	727,591	97.5%	97.5%	97.5%	10,328			7,514,787	3,625,884	0.50	
24	St Lucie 2												
25	Nuclear		623,512				10,257	6,395,178	1,000,000	6,395,178	2,775,507	0.45	0.43
26	Plant Unit Info	859.6	623,512	97.5%	97.5%	97.5%	10,257			6,395,178	2,775,507	0.45	
27	Sunshine Gateway PV Solar												
28	Solar		11,842					N/A	N/A	N/A	N/A	N/A	N/A
29	Plant Unit Info	74.5	11,842	21.4%	N/A	21.4%	N/A						
30	Sweet Bay PV Solar												
31	Solar		11,836					N/A	N/A	N/A	N/A	N/A	N/A
32	Plant Unit Info	74.5	11,836	21.4%	N/A	21.4%	N/A						
33	Trailside PV Solar												
34	Solar		11,447					N/A	N/A	N/A	N/A	N/A	N/A
35	Plant Unit Info	74.5	11,447	20.7%	N/A	20.7%	N/A						
36	Turkey Point 3												
37	Nuclear		623,100				10,541	6,568,284	1,000,000	6,568,284	3,161,801	0.51	0.48
38	Plant Unit Info	859.0	623,100	97.5%	97.5%	97.5%	10,541			6,568,284	3,161,801	0.51	
39	Turkey Point 4												
40	Nuclear		629,647				10,432	6,568,480	1,000,000	6,568,480	3,790,670	0.60	0.58
41	Plant Unit Info	868.0	629,647	97.5%	97.5%	97.5%	10,432			6,568,480	3,790,670	0.60	
42	Turkey Point 5												
43	Light Oil		0					0	0	0	0	0.00	0.00

ESTIMATED FOR THE PERIOD OF: JANUARY 2021 THROUGH DECEMBER 2021

(1) Line No.	(2) PLANT UNIT	(3) Net Capability (MW)	(4) Net Generation (MWH)	(5) Capacity Factor	(6) Equivalent Availability Factor	(7) Net Output Factor	(8) Avg Net Heat Rate (BTU/KWH)	(9) Fuel Burned (Units)	(10) Fuel Heat Value (BTU/Unit)	(11) Fuel Burned (MMBTU)	(12) As Burned Fuel Cost ($)	(13) Fuel Cost per KWH (cents/KWH)	(14) Cost of Fuel ($/Unit)
1	Gas		325,732				7,413	2,414,674	1,000,000	2,414,674	11,855,293	3.64	4.91
2	Plant Unit Info	1,294.0	325,732	33.8%	93.9%	33.8%	7,413			2,414,674	11,855,293	3.64	
3	Twin Lakes PV Solar												
4	Solar		11,306					N/A	N/A	N/A	N/A	N/A	N/A
5	Plant Unit Info	74.5	11,306	20.4%	N/A	20.4%	N/A						
6	Union Springs PV Solar												
7	Solar		11,340					N/A	N/A	N/A	N/A	N/A	N/A
8	Plant Unit Info	74.5	11,340	20.5%	N/A	20.5%	N/A						
9	WCEC 01												
10	Light Oil		0					0	0	0	0	0.00	0.00
11	Gas		450,992				6,855	3,091,437	1,000,000	3,091,437	15,066,896	3.34	4.87
12	Plant Unit Info	1,248.0	450,992	48.6%	93.7%	48.6%	6,855			3,091,437	15,066,896	3.34	
13	WCEC 02												
14	Light Oil		0					0	0	0	0	0.00	0.00
15	Gas		618,360				6,706	4,147,020	1,000,000	4,147,020	20,211,522	3.27	4.87
16	Plant Unit Info	1,248.0	618,360	66.6%	93.7%	66.6%	6,706			4,147,020	20,211,522	3.27	
17	WCEC 03												
18	Light Oil		0					0	0	0	0	0.00	0.00
19	Gas		593,891				6,771	4,021,387	1,000,000	4,021,387	19,600,001	3.30	4.87
20	Plant Unit Info	1,254.0	593,891	63.7%	93.7%	63.7%	6,771			4,021,387	19,600,001	3.30	
21	Wildflower PV Solar												
22	Solar		13,496					N/A	N/A	N/A	N/A	N/A	N/A
23	Plant Unit Info	74.5	13,496	24.4%	N/A	24.4%	N/A						
24	Willow PV Solar												
25	Solar		0					N/A	N/A	N/A	N/A	N/A	N/A
26	Plant Unit Info	0.0	0	N/A	N/A	N/A	N/A						
27	System Totals												
28	Plant Unit Info	28,427	9,191,215				7,599			69,843,060	217,911,217	2.37	
29													
30													
31													
32													
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ESTIMATED FOR THE PERIOD OF: JANUARY 2021 THROUGH DECEMBER 2021

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.	PLANT UNIT	Net Capability (MW)	Net Generation (MWH)	Capacity Factor	Equivalent Availability Factor	Net Output Factor	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost ($)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel ($/Unit)
1	**Feb - 2021**												
2	Babcock PV Solar												
3	Solar		12,520					N/A	N/A	N/A	N/A	N/A	N/A
4	Plant Unit Info	74.5	12,520	25.0%	N/A	25.0%	N/A						
5	Babcock Preserve PV Solar												
6	Solar		13,531					N/A	N/A	N/A	N/A	N/A	N/A
7	Plant Unit Info	74.5	13,531	27.0%	N/A	27.0%	N/A						
8	Barefoot PV Solar												
9	Solar		12,676					N/A	N/A	N/A	N/A	N/A	N/A
10	Plant Unit Info	74.5	12,676	25.3%	N/A	25.3%	N/A						
11	Blue Cypress PV Solar												
12	Solar		13,303					N/A	N/A	N/A	N/A	N/A	N/A
13	Plant Unit Info	74.5	13,303	26.6%	N/A	26.6%	N/A						
14	Blue Heron PV Solar												
15	Solar		13,531					N/A	N/A	N/A	N/A	N/A	N/A
16	Plant Unit Info	74.5	13,531	27.0%	N/A	27.0%	N/A						
17	CCEC 3												
18	Light Oil		0					0	0	0	0	0.00	0.00
19	Gas		452,014				6,744	3,048,564	1,000,000	3,048,564	14,714,441	3.26	4.83
20	Plant Unit Info	1,326.0	452,014	50.7%	81.5%	57.2%	6,744			3,048,564	14,714,441	3.26	
21	Cattle Ranch PV Solar												
22	Solar		12,340					N/A	N/A	N/A	N/A	N/A	N/A
23	Plant Unit Info	74.5	12,340	24.7%	N/A	24.7%	N/A						
24	Citrus PV Solar												
25	Solar		12,263					N/A	N/A	N/A	N/A	N/A	N/A
26	Plant Unit Info	74.5	12,263	24.5%	N/A	24.5%	N/A						
27	Coral Farms PV Solar												
28	Solar		13,305					N/A	N/A	N/A	N/A	N/A	N/A
29	Plant Unit Info	74.5	13,305	26.6%	N/A	26.6%	N/A						
30	Desoto Solar												
31	Solar		3,239					N/A	N/A	N/A	N/A	N/A	N/A
32	Plant Unit Info	25.0	3,239	19.3%	N/A	19.3%	N/A						
33	Discovery PV Solar												
34	Solar		0					N/A	N/A	N/A	N/A	N/A	N/A
35	Plant Unit Info	0.0	0	N/A	N/A	N/A	N/A						
36	Egret PV Solar												
37	Solar		11,970					N/A	N/A	N/A	N/A	N/A	N/A
38	Plant Unit Info	74.5	11,970	23.9%	N/A	23.9%	N/A						
39	Fort Drum PV Solar												
40	Solar		0					N/A	N/A	N/A	N/A	N/A	N/A
41	Plant Unit Info	0.0	0	N/A	N/A	N/A	N/A						
42	Fort Myers 2												
43	Gas		515,901				7,359	3,796,508	1,000,000	3,796,508	18,337,653	3.55	4.83

ESTIMATED FOR THE PERIOD OF: JANUARY 2021 THROUGH DECEMBER 2021

(1) Line No.	(2) PLANT UNIT	(3) Net Capability (MW)	(4) Net Generation (MWH)	(5) Capacity Factor	(6) Equivalent Availability Factor	(7) Net Output Factor	(8) Avg Net Heat Rate (BTU/KWH)	(9) Fuel Burned (Units)	(10) Fuel Heat Value (BTU/Unit)	(11) Fuel Burned (MMBTU)	(12) As Burned Fuel Cost ($)	(13) Fuel Cost per KWH (cents/KWH)	(14) Cost of Fuel ($/Unit)
1	Plant Unit Info	1,770.0	515,901	43.4%	91.6%	46.7%	7,359			3,796,508	18,337,653	3.55	
2	Fort Myers 3A												
3	Light Oil		0					0	0	0	0	0.00	0.00
4	Gas		0					0	0	0	0	0.00	0.00
5	Plant Unit Info	189.0	0	N/A	68.7%	N/A	N/A						
6	Fort Myers 3B												
7	Light Oil		450				16,229	1,253	5,829,994	7,303	111,182	24.71	88.76
8	Gas		0					0	0	0	0	0.00	0.00
9	Plant Unit Info	193.0	450	0.4%	68.7%	0.5%	16,229			7,303	111,182	24.71	
10	Fort Myers 3C												
11	Light Oil		0					0	0	0	0	0.00	0.00
12	Gas		908				11,128	10,104	1,000,000	10,104	47,804	5.26	4.73
13	Plant Unit Info	221.0	908	0.6%	68.7%	0.8%	11,128			10,104	47,804	5.26	
14	Fort Myers 3D												
15	Light Oil		0					0	0	0	0	0.00	0.00
16	Gas		1,857				11,016	20,457	1,000,000	20,457	97,809	5.27	4.78
17	Plant Unit Info	221.0	1,857	1.3%	68.7%	1.7%	11,016			20,457	97,809	5.27	
18	Echo River PV Solar												
19	Solar		12,997					N/A	N/A	N/A	N/A	N/A	N/A
20	Plant Unit Info	74.5	12,997	26.0%	N/A	26.0%	N/A						
21	Hammock PV Solar												
22	Solar		13,943					N/A	N/A	N/A	N/A	N/A	N/A
23	Plant Unit Info	74.5	13,943	27.9%	N/A	27.9%	N/A						
24	Hibiscus PV Solar												
25	Solar		12,411					N/A	N/A	N/A	N/A	N/A	N/A
26	Plant Unit Info	74.5	12,411	24.8%	N/A	24.8%	N/A						
27	Horizon PV Solar												
28	Solar		12,944					N/A	N/A	N/A	N/A	N/A	N/A
29	Plant Unit Info	74.5	12,944	25.9%	N/A	25.9%	N/A						
30	Indian River PV Solar												
31	Solar		13,293					N/A	N/A	N/A	N/A	N/A	N/A
32	Plant Unit Info	74.5	13,293	26.6%	N/A	26.6%	N/A						
33	Indiantown												
34	Plant Unit Info	0.0	0	N/A	N/A	N/A	N/A						
35	Interstate PV Solar												
36	Solar		12,816					N/A	N/A	N/A	N/A	N/A	N/A
37	Plant Unit Info	74.5	12,816	25.6%	N/A	25.6%	N/A						
38	Lakeside PV Solar												
39	Solar		13,361					N/A	N/A	N/A	N/A	N/A	N/A
40	Plant Unit Info	74.5	13,361	26.7%	N/A	26.7%	N/A						
41	Lauderdale 6A												
42	Light Oil		0					0	0	0	0	0.00	0.00
43	Gas		3,030				10,599	32,116	1,000,000	32,116	154,226	5.09	4.80

ESTIMATED FOR THE PERIOD OF: JANUARY 2021 THROUGH DECEMBER 2021

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.	PLANT UNIT	Net Capability (MW)	Net Generation (MWH)	Capacity Factor	Equivalent Availability Factor	Net Output Factor	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost ($)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel ($/Unit)
1	Plant Unit Info	218.0	3,030	2.1%	44.0%	4.1%	10,599			32,116	154,226	5.09	
2	Lauderdale 6B												
3	Light Oil		0					0	0	0	0	0.00	0.00
4	Gas		3,434				10,565	36,279	1,000,000	36,279	174,006	5.07	4.80
5	Plant Unit Info	218.0	3,434	2.3%	94.0%	2.3%	10,565			36,279	174,006	5.07	
6	Lauderdale 6C												
7	Light Oil		0					0	0	0	0	0.00	0.00
8	Gas		0					0	0	0	0	0.00	0.00
9	Plant Unit Info	218.0	0	N/A	69.0%	N/A	N/A						
10	Lauderdale 6D												
11	Light Oil		561				15,004	1,444	5,829,997	8,417	101,429	18.08	70.25
12	Gas		0					0	0	0	0	0.00	0.00
13	Plant Unit Info	218.0	561	0.4%	94.0%	0.4%	15,004			8,417	101,429	18.08	
14	Lauderdale 6E												
15	Light Oil		450				17,167	1,325	5,830,013	7,725	93,090	20.69	70.25
16	Gas		0					0	0	0	0	0.00	0.00
17	Plant Unit Info	218.0	450	0.3%	69.0%	0.4%	17,167			7,725	93,090	20.69	
18	Loggerhead PV Solar												
19	Solar		13,547					N/A	N/A	N/A	N/A	N/A	N/A
20	Plant Unit Info	74.5	13,547	27.1%	N/A	27.1%	N/A						
21	Magnolia PV Solar												
22	Solar		12,057					N/A	N/A	N/A	N/A	N/A	N/A
23	Plant Unit Info	74.5	12,057	24.1%	N/A	24.1%	N/A						
24	Manatee 1												
25	Heavy Oil		710				14,078	1,561	6,400,005	9,989	107,002	15.08	68.56
26	Gas		2,002				14,078	28,189	1,000,000	28,189	132,606	6.62	4.70
27	Plant Unit Info	797.0	2,712	0.5%	58.4%	0.8%	14,078			38,178	239,607	8.84	
28	Manatee 2												
29	Heavy Oil		713				13,460	1,499	6,399,979	9,596	102,792	14.42	68.56
30	Gas		4,897				13,460	65,914	1,000,000	65,914	313,722	6.41	4.76
31	Plant Unit Info	797.0	5,610	1.1%	58.4%	1.6%	13,460			75,510	416,514	7.42	
32	Manatee 3												
33	Gas		139,878				7,850	1,097,990	1,000,000	1,097,990	5,255,495	3.76	4.79
34	Plant Unit Info	1,254.0	139,878	16.6%	93.9%	16.6%	7,850			1,097,990	5,255,495	3.76	
35	Manatee PV Solar												
36	Solar		12,186					N/A	N/A	N/A	N/A	N/A	N/A
37	Plant Unit Info	74.5	12,186	24.3%	N/A	24.3%	N/A						
38	Martin 3												
39	Gas		128,923				7,679	990,006	1,000,000	990,006	4,744,338	3.68	4.79
40	Plant Unit Info	492.0	128,923	39.0%	93.9%	39.0%	7,679			990,006	4,744,338	3.68	
41	Martin 4												
42	Gas		18,836				8,335	157,005	1,000,000	157,005	749,575	3.98	4.77
43	Plant Unit Info	492.0	18,836	5.7%	93.9%	5.7%	8,335			157,005	749,575	3.98	

ESTIMATED FOR THE PERIOD OF: JANUARY 2021 THROUGH DECEMBER 2021

(1) Line No.	(2) PLANT UNIT	(3) Net Capability (MW)	(4) Net Generation (MWH)	(5) Capacity Factor	(6) Equivalent Availability Factor	(7) Net Output Factor	(8) Avg Net Heat Rate (BTU/KWH)	(9) Fuel Burned (Units)	(10) Fuel Heat Value (BTU/Unit)	(11) Fuel Burned (MMBTU)	(12) As Burned Fuel Cost ($)	(13) Fuel Cost per KWH (cents/KWH)	(14) Cost of Fuel ($/Unit)
1	Martin 8 Solar												
2	Solar		8,484					N/A	N/A	N/A	N/A	N/A	N/A
3	Plant Unit Info	75.0	8,484	16.8%	N/A	16.8%	N/A						
4	Martin 8												
5	Light Oil		0					0	0	0	0	0.00	0.00
6	Gas		99,736				7,952	793,081	1,000,000	793,081	3,795,256	3.81	4.79
7	Plant Unit Info	1,258.0	99,736	11.8%	87.3%	12.5%	7,952			793,081	3,795,256	3.81	
8	Miami-Dade PV Solar												
9	Solar		13,157					N/A	N/A	N/A	N/A	N/A	N/A
10	Plant Unit Info	74.5	13,157	26.3%	N/A	26.3%	N/A						
11	Nassau PV Solar												
12	Solar		11,914					N/A	N/A	N/A	N/A	N/A	N/A
13	Plant Unit Info	74.5	11,914	23.8%	N/A	23.8%	N/A						
14	Northern Preserve PV Solar												
15	Solar		11,761					N/A	N/A	N/A	N/A	N/A	N/A
16	Plant Unit Info	74.5	11,761	23.5%	N/A	23.5%	N/A						
17	Okeechobee 1												
18	Light Oil		0					0	0	0	0	0.00	0.00
19	Gas		489,609				6,310	3,089,221	1,000,000	3,089,221	14,912,255	3.05	4.83
20	Plant Unit Info	1,655.1	489,609	44.0%	46.6%	82.2%	6,310			3,089,221	14,912,255	3.05	
21	Okeechobee PV Solar												
22	Solar		12,725					N/A	N/A	N/A	N/A	N/A	N/A
23	Plant Unit Info	74.5	12,725	25.4%	N/A	25.4%	N/A						
24	Orange Blossom PV Solar												
25	Solar		0					N/A	N/A	N/A	N/A	N/A	N/A
26	Plant Unit Info	0.0	0	N/A	N/A	N/A	N/A						
27	Palm Bay PV Solar												
28	Solar		0					N/A	N/A	N/A	N/A	N/A	N/A
29	Plant Unit Info	0.0	0	N/A	N/A	N/A	N/A						
30	PEEC												
31	Gas		754,271				6,359	4,796,186	1,000,000	4,796,186	23,155,000	3.07	4.83
32	Plant Unit Info	1,283.0	754,271	87.5%	93.0%	87.5%	6,359			4,796,186	23,155,000	3.07	
33	Pelican PV Solar												
34	Solar		0					N/A	N/A	N/A	N/A	N/A	N/A
35	Plant Unit Info	0.0	0	N/A	N/A	N/A	N/A						
36	Pioneer Trail PV Solar												
37	Solar		11,948					N/A	N/A	N/A	N/A	N/A	N/A
38	Plant Unit Info	74.5	11,948	23.9%	N/A	23.9%	N/A						
39	Riviera 5												
40	Light Oil		0					0	0	0	0	0.00	0.00
41	Gas		535,468				6,745	3,611,666	1,000,000	3,611,666	17,424,398	3.25	4.82
42	Plant Unit Info	1,326.0	535,468	60.1%	93.4%	60.1%	6,745			3,611,666	17,424,398	3.25	
43	Rodeo PV Solar												

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(1) Line No.	(2) PLANT UNIT	(3) Net Capability (MW)	(4) Net Generation (MWH)	(5) Capacity Factor	(6) Equivalent Availability Factor	(7) Net Output Factor	(8) Avg Net Heat Rate (BTU/KWH)	(9) Fuel Burned (Units)	(10) Fuel Heat Value (BTU/Unit)	(11) Fuel Burned (MMBTU)	(12) As Burned Fuel Cost ($)	(13) Fuel Cost per KWH (cents/KWH)	(14) Cost of Fuel ($/Unit)
1	Solar		0					N/A	N/A	N/A	N/A	N/A	N/A
2	Plant Unit Info	0.0	0	N/A	N/A	N/A	N/A						
3	Sabal Palm PV Solar												
4	Solar		0					N/A	N/A	N/A	N/A	N/A	N/A
5	Plant Unit Info	0.0	0	N/A	N/A	N/A	N/A						
6	Sanford 4												
7	Gas		49,512				7,997	395,935	1,000,000	395,935	1,907,402	3.85	4.82
8	Plant Unit Info	1,192.0	49,512	6.2%	94.1%	6.2%	7,997			395,935	1,907,402	3.85	
9	Sanford 5												
10	Gas		330,375				7,209	2,381,781	1,000,000	2,381,781	11,496,573	3.48	4.83
11	Plant Unit Info	1,192.0	330,375	41.2%	94.1%	41.2%	7,209			2,381,781	11,496,573	3.48	
12	Scherer 4												
13	Coal		167,279				11,407	112,249	17,000,001	1,908,230	4,835,208	2.89	43.08
14	Plant Unit Info	626.0	167,279	39.8%	92.2%	39.8%	11,407			1,908,230	4,835,208	2.89	
15	Southfork PV Solar												
16	Solar		14,131					N/A	N/A	N/A	N/A	N/A	N/A
17	Plant Unit Info	74.5	14,131	28.2%	N/A	28.2%	N/A						
18	Space Coast												
19	Solar		1,274					N/A	N/A	N/A	N/A	N/A	N/A
20	Plant Unit Info	10.0	1,274	19.0%	N/A	19.0%	N/A						
21	St Lucie 1												
22	Nuclear		657,179				10,328	6,787,549	1,000,000	6,787,549	3,274,992	0.50	0.48
23	Plant Unit Info	1,003.0	657,179	97.5%	97.5%	97.5%	10,328			6,787,549	3,274,992	0.50	
24	St Lucie 2												
25	Nuclear		563,172				10,257	5,776,289	1,000,000	5,776,289	2,506,910	0.45	0.43
26	Plant Unit Info	859.6	563,172	97.5%	97.5%	97.5%	10,257			5,776,289	2,506,910	0.45	
27	Sunshine Gateway PV Solar												
28	Solar		11,892					N/A	N/A	N/A	N/A	N/A	N/A
29	Plant Unit Info	74.5	11,892	23.8%	N/A	23.8%	N/A						
30	Sweet Bay PV Solar												
31	Solar		12,117					N/A	N/A	N/A	N/A	N/A	N/A
32	Plant Unit Info	74.5	12,117	24.2%	N/A	24.2%	N/A						
33	Trailside PV Solar												
34	Solar		12,158					N/A	N/A	N/A	N/A	N/A	N/A
35	Plant Unit Info	74.5	12,158	24.3%	N/A	24.3%	N/A						
36	Turkey Point 3												
37	Nuclear		562,800				10,541	5,932,644	1,000,000	5,932,644	2,855,821	0.51	0.48
38	Plant Unit Info	859.0	562,800	97.5%	97.5%	97.5%	10,541			5,932,644	2,855,821	0.51	
39	Turkey Point 4												
40	Nuclear		568,714				10,432	5,932,821	1,000,000	5,932,821	3,423,831	0.60	0.58
41	Plant Unit Info	868.0	568,714	97.5%	97.5%	97.5%	10,432			5,932,821	3,423,831	0.60	
42	Turkey Point 5												
43	Light Oil		0					0	0	0	0	0.00	0.00

ESTIMATED FOR THE PERIOD OF: JANUARY 2021 THROUGH DECEMBER 2021

(1) Line No.	(2) PLANT UNIT	(3) Net Capability (MW)	(4) Net Generation (MWH)	(5) Capacity Factor	(6) Equivalent Availability Factor	(7) Net Output Factor	(8) Avg Net Heat Rate (BTU/KWH)	(9) Fuel Burned (Units)	(10) Fuel Heat Value (BTU/Unit)	(11) Fuel Burned (MMBTU)	(12) As Burned Fuel Cost ($)	(13) Fuel Cost per KWH (cents/KWH)	(14) Cost of Fuel ($/Unit)
1	Gas		336,960				7,310	2,463,102	1,000,000	2,463,102	11,888,591	3.53	4.83
2	Plant Unit Info	1,294.0	336,960	38.8%	93.9%	38.8%	7,310			2,463,102	11,888,591	3.53	
3	Twin Lakes PV Solar												
4	Solar		12,008					N/A	N/A	N/A	N/A	N/A	N/A
5	Plant Unit Info	74.5	12,008	24.0%	N/A	24.0%	N/A						
6	Union Springs PV Solar												
7	Solar		12,045					N/A	N/A	N/A	N/A	N/A	N/A
8	Plant Unit Info	74.5	12,045	24.1%	N/A	24.1%	N/A						
9	WCEC 01												
10	Light Oil		0					0	0	0	0	0.00	0.00
11	Gas		504,592				6,793	3,427,739	1,000,000	3,427,739	16,424,749	3.26	4.79
12	Plant Unit Info	1,248.0	504,592	60.2%	93.7%	60.2%	6,793			3,427,739	16,424,749	3.26	
13	WCEC 02												
14	Light Oil		0					0	0	0	0	0.00	0.00
15	Gas		604,860				6,713	4,060,409	1,000,000	4,060,409	19,458,208	3.22	4.79
16	Plant Unit Info	1,248.0	604,860	72.1%	93.7%	72.1%	6,713			4,060,409	19,458,208	3.22	
17	WCEC 03												
18	Light Oil		0					0	0	0	0	0.00	0.00
19	Gas		523,088				6,748	3,529,753	1,000,000	3,529,753	16,917,261	3.23	4.79
20	Plant Unit Info	1,254.0	523,088	62.1%	77.0%	74.6%	6,748			3,529,753	16,917,261	3.23	
21	Wildflower PV Solar												
22	Solar		13,407					N/A	N/A	N/A	N/A	N/A	N/A
23	Plant Unit Info	74.5	13,407	26.8%	N/A	26.8%	N/A						
24	Willow PV Solar												
25	Solar		0					N/A	N/A	N/A	N/A	N/A	N/A
26	Plant Unit Info	0.0	0	N/A	N/A	N/A	N/A						
27	System Totals												
28	Plant Unit Info	28,427	8,429,434				7,618			64,212,569	199,513,626	2.37	
29													
30													
31													
32													
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ESTIMATED FOR THE PERIOD OF: JANUARY 2021 THROUGH DECEMBER 2021

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.	PLANT UNIT	Net Capability (MW)	Net Generation (MWH)	Capacity Factor	Equivalent Availability Factor	Net Output Factor	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost ($)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel ($/Unit)
1	**Mar - 2021**												
2	Babcock PV Solar												
3	Solar		15,355					N/A	N/A	N/A	N/A	N/A	N/A
4	Plant Unit Info	74.5	15,355	27.7%	N/A	27.7%	N/A						
5	Babcock Preserve PV Solar												
6	Solar		16,622					N/A	N/A	N/A	N/A	N/A	N/A
7	Plant Unit Info	74.5	16,622	30.0%	N/A	30.0%	N/A						
8	Barefoot PV Solar												
9	Solar		16,036					N/A	N/A	N/A	N/A	N/A	N/A
10	Plant Unit Info	74.5	16,036	28.9%	N/A	28.9%	N/A						
11	Blue Cypress PV Solar												
12	Solar		16,632					N/A	N/A	N/A	N/A	N/A	N/A
13	Plant Unit Info	74.5	16,632	30.0%	N/A	30.0%	N/A						
14	Blue Heron PV Solar												
15	Solar		16,622					N/A	N/A	N/A	N/A	N/A	N/A
16	Plant Unit Info	74.5	16,622	30.0%	N/A	30.0%	N/A						
17	CCEC 3												
18	Light Oil		0					0	0	0	0	0.00	0.00
19	Gas		656,579				6,710	4,405,467	1,000,000	4,405,467	21,026,935	3.20	4.77
20	Plant Unit Info	1,326.0	656,579	66.6%	93.4%	66.6%	6,710			4,405,467	21,026,935	3.20	
21	Cattle Ranch PV Solar												
22	Solar		16,816					N/A	N/A	N/A	N/A	N/A	N/A
23	Plant Unit Info	74.5	16,816	30.3%	N/A	30.3%	N/A						
24	Citrus PV Solar												
25	Solar		15,251					N/A	N/A	N/A	N/A	N/A	N/A
26	Plant Unit Info	74.5	15,251	27.5%	N/A	27.5%	N/A						
27	Coral Farms PV Solar												
28	Solar		16,484					N/A	N/A	N/A	N/A	N/A	N/A
29	Plant Unit Info	74.5	16,484	29.7%	N/A	29.7%	N/A						
30	Desoto Solar												
31	Solar		4,460					N/A	N/A	N/A	N/A	N/A	N/A
32	Plant Unit Info	25.0	4,460	24.0%	N/A	24.0%	N/A						
33	Discovery PV Solar												
34	Solar		0					N/A	N/A	N/A	N/A	N/A	N/A
35	Plant Unit Info	0.0	0	N/A	N/A	N/A	N/A						
36	Egret PV Solar												
37	Solar		16,312					N/A	N/A	N/A	N/A	N/A	N/A
38	Plant Unit Info	74.5	16,312	29.4%	N/A	29.4%	N/A						
39	Fort Drum PV Solar												
40	Solar		0					N/A	N/A	N/A	N/A	N/A	N/A
41	Plant Unit Info	0.0	0	N/A	N/A	N/A	N/A						
42	Fort Myers 2												
43	Gas		594,340				7,264	4,317,455	1,000,000	4,317,455	20,596,544	3.47	4.77

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(1) Line No.	(2) PLANT UNIT	(3) Net Capability (MW)	(4) Net Generation (MWH)	(5) Capacity Factor	(6) Equivalent Availability Factor	(7) Net Output Factor	(8) Avg Net Heat Rate (BTU/KWH)	(9) Fuel Burned (Units)	(10) Fuel Heat Value (BTU/Unit)	(11) Fuel Burned (MMBTU)	(12) As Burned Fuel Cost ($)	(13) Fuel Cost per KWH (cents/KWH)	(14) Cost of Fuel ($/Unit)
1	Plant Unit Info	1,770.0	594,340	45.1%	88.7%	53.8%	7,264			4,317,455	20,596,544	3.47	
2	Fort Myers 3A												
3	Light Oil		0					0	0	0	0	0.00	0.00
4	Gas		0					0	0	0	0	0.00	0.00
5	Plant Unit Info	189.0	0	N/A	93.7%	N/A	N/A						
6	Fort Myers 3B												
7	Light Oil		0					0	0	0	0	0.00	0.00
8	Gas		0					0	0	0	0	0.00	0.00
9	Plant Unit Info	193.0	0	N/A	93.7%	N/A	N/A						
10	Fort Myers 3C												
11	Light Oil		0					0	0	0	0	0.00	0.00
12	Gas		0					0	0	0	0	0.00	0.00
13	Plant Unit Info	221.0	0	N/A	93.7%	N/A	N/A						
14	Fort Myers 3D												
15	Light Oil		0					0	0	0	0	0.00	0.00
16	Gas		0					0	0	0	0	0.00	0.00
17	Plant Unit Info	221.0	0	N/A	93.7%	N/A	N/A						
18	Echo River PV Solar												
19	Solar		17,543					N/A	N/A	N/A	N/A	N/A	N/A
20	Plant Unit Info	74.5	17,543	31.7%	N/A	31.7%	N/A						
21	Hammock PV Solar												
22	Solar		17,187					N/A	N/A	N/A	N/A	N/A	N/A
23	Plant Unit Info	74.5	17,187	31.0%	N/A	31.0%	N/A						
24	Hibiscus PV Solar												
25	Solar		15,687					N/A	N/A	N/A	N/A	N/A	N/A
26	Plant Unit Info	74.5	15,687	28.3%	N/A	28.3%	N/A						
27	Horizon PV Solar												
28	Solar		16,542					N/A	N/A	N/A	N/A	N/A	N/A
29	Plant Unit Info	74.5	16,542	29.8%	N/A	29.8%	N/A						
30	Indian River PV Solar												
31	Solar		16,622					N/A	N/A	N/A	N/A	N/A	N/A
32	Plant Unit Info	74.5	16,622	30.0%	N/A	30.0%	N/A						
33	Indiantown												
34	Plant Unit Info	0.0	0	N/A	N/A	N/A	N/A						
35	Interstate PV Solar												
36	Solar		15,908					N/A	N/A	N/A	N/A	N/A	N/A
37	Plant Unit Info	74.5	15,908	28.7%	N/A	28.7%	N/A						
38	Lakeside PV Solar												
39	Solar		16,413					N/A	N/A	N/A	N/A	N/A	N/A
40	Plant Unit Info	74.5	16,413	29.6%	N/A	29.6%	N/A						
41	Lauderdale 6A												
42	Light Oil		0					0	0	0	0	0.00	0.00
43	Gas		2,020				10,600	21,411	1,000,000	21,411	99,721	4.94	4.66

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(1) Line No.	(2) PLANT UNIT	(3) Net Capability (MW)	(4) Net Generation (MWH)	(5) Capacity Factor	(6) Equivalent Availability Factor	(7) Net Output Factor	(8) Avg Net Heat Rate (BTU/KWH)	(9) Fuel Burned (Units)	(10) Fuel Heat Value (BTU/Unit)	(11) Fuel Burned (MMBTU)	(12) As Burned Fuel Cost ($)	(13) Fuel Cost per KWH (cents/KWH)	(14) Cost of Fuel ($/Unit)
1	Plant Unit Info	218.0	2,020	1.3%	94.0%	1.3%	10,600			21,411	99,721	4.94	
2	Lauderdale 6B												
3	Light Oil		0					0	0	0	0	0.00	0.00
4	Gas		1,010				10,599	10,705	1,000,000	10,705	51,275	5.08	4.79
5	Plant Unit Info	218.0	1,010	0.6%	94.0%	0.6%	10,599			10,705	51,275	5.08	
6	Lauderdale 6C												
7	Light Oil		0					0	0	0	0	0.00	0.00
8	Gas		0					0	0	0	0	0.00	0.00
9	Plant Unit Info	218.0	0	N/A	94.0%	N/A	N/A						
10	Lauderdale 6D												
11	Light Oil		0					0	0	0	0	0.00	0.00
12	Gas		0					0	0	0	0	0.00	0.00
13	Plant Unit Info	218.0	0	N/A	94.0%	N/A	N/A						
14	Lauderdale 6E												
15	Light Oil		0					0	0	0	0	0.00	0.00
16	Gas		0					0	0	0	0	0.00	0.00
17	Plant Unit Info	218.0	0	N/A	94.0%	N/A	N/A						
18	Loggerhead PV Solar												
19	Solar		16,909					N/A	N/A	N/A	N/A	N/A	N/A
20	Plant Unit Info	74.5	16,909	30.5%	N/A	30.5%	N/A						
21	Magnolia PV Solar												
22	Solar		16,430					N/A	N/A	N/A	N/A	N/A	N/A
23	Plant Unit Info	74.5	16,430	29.6%	N/A	29.6%	N/A						
24	Manatee 1												
25	Heavy Oil		-					0	0	0	0	0.00	0.00
26	Gas		0					0	0	0	0	0.00	0.00
27	Plant Unit Info	797.0	0	N/A	94.1%	N/A	N/A						
28	Manatee 2												
29	Heavy Oil		-					0	0	0	0	0.00	0.00
30	Gas		0					0	0	0	0	0.00	0.00
31	Plant Unit Info	797.0	0	N/A	94.1%	N/A	N/A						
32	Manatee 3												
33	Gas		291,925				7,515	2,193,764	1,000,000	2,193,764	10,395,541	3.56	4.74
34	Plant Unit Info	1,254.0	291,925	31.3%	93.9%	31.3%	7,515			2,193,764	10,395,541	3.56	
35	Manatee PV Solar												
36	Solar		15,386					N/A	N/A	N/A	N/A	N/A	N/A
37	Plant Unit Info	74.5	15,386	27.8%	N/A	27.8%	N/A						
38	Martin 3												
39	Gas		20,584				9,540	196,376	1,000,000	196,376	925,537	4.50	4.71
40	Plant Unit Info	492.0	20,584	5.6%	93.9%	5.6%	9,540			196,376	925,537	4.50	
41	Martin 4												
42	Gas		31,178				8,939	278,712	1,000,000	278,712	1,313,748	4.21	4.71
43	Plant Unit Info	492.0	31,178	8.5%	93.9%	8.5%	8,939			278,712	1,313,748	4.21	

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(1) Line No.	(2) PLANT UNIT	(3) Net Capability (MW)	(4) Net Generation (MWH)	(5) Capacity Factor	(6) Equivalent Availability Factor	(7) Net Output Factor	(8) Avg Net Heat Rate (BTU/KWH)	(9) Fuel Burned (Units)	(10) Fuel Heat Value (BTU/Unit)	(11) Fuel Burned (MMBTU)	(12) As Burned Fuel Cost ($)	(13) Fuel Cost per KWH (cents/KWH)	(14) Cost of Fuel ($/Unit)
1	Martin 8 Solar												
2	Solar		11,873					N/A	N/A	N/A	N/A	N/A	N/A
3	Plant Unit Info	75.0	11,873	21.3%	N/A	21.3%	N/A						
4	Martin 8												
5	Light Oil		0					0	0	0	0	0.00	0.00
6	Gas		142,424				7,835	1,115,891	1,000,000	1,115,891	5,279,319	3.71	4.73
7	Plant Unit Info	1,258.0	142,424	15.2%	68.5%	19.5%	7,835			1,115,891	5,279,319	3.71	
8	Miami-Dade PV Solar												
9	Solar		16,199					N/A	N/A	N/A	N/A	N/A	N/A
10	Plant Unit Info	74.5	16,199	29.2%	N/A	29.2%	N/A						
11	Nassau PV Solar												
12	Solar		16,236					N/A	N/A	N/A	N/A	N/A	N/A
13	Plant Unit Info	74.5	16,236	29.3%	N/A	29.3%	N/A						
14	Northern Preserve PV Solar												
15	Solar		14,447					N/A	N/A	N/A	N/A	N/A	N/A
16	Plant Unit Info	74.5	14,447	26.1%	N/A	26.1%	N/A						
17	Okeechobee 1												
18	Light Oil		0					0	0	0	0	0.00	0.00
19	Gas		839,821				6,285	5,278,345	1,000,000	5,278,345	25,154,986	3.00	4.77
20	Plant Unit Info	1,655.1	839,821	68.2%	70.4%	88.1%	6,285			5,278,345	25,154,986	3.00	
21	Okeechobee PV Solar												
22	Solar		15,979					N/A	N/A	N/A	N/A	N/A	N/A
23	Plant Unit Info	74.5	15,979	28.8%	N/A	28.8%	N/A						
24	Orange Blossom PV Solar												
25	Solar		0					N/A	N/A	N/A	N/A	N/A	N/A
26	Plant Unit Info	0.0	0	N/A	N/A	N/A	N/A						
27	Palm Bay PV Solar												
28	Solar		0					N/A	N/A	N/A	N/A	N/A	N/A
29	Plant Unit Info	0.0	0	N/A	N/A	N/A	N/A						
30	PEEC												
31	Gas		572,599				6,349	3,635,221	1,000,000	3,635,221	17,376,123	3.03	4.78
32	Plant Unit Info	1,283.0	572,599	60.0%	60.7%	88.6%	6,349			3,635,221	17,376,123	3.03	
33	Pelican PV Solar												
34	Solar		5,815					N/A	N/A	N/A	N/A	N/A	N/A
35	Plant Unit Info	74.5	5,815	10.5%	35.5%	29.6%	N/A						
36	Pioneer Trail PV Solar												
37	Solar		15,336					N/A	N/A	N/A	N/A	N/A	N/A
38	Plant Unit Info	74.5	15,336	27.7%	N/A	27.7%	N/A						
39	Riviera 5												
40	Light Oil		0					0	0	0	0	0.00	0.00
41	Gas		696,686				6,692	4,662,177	1,000,000	4,662,177	22,190,917	3.19	4.76
42	Plant Unit Info	1,326.0	696,686	70.6%	93.4%	70.6%	6,692			4,662,177	22,190,917	3.19	
43	Rodeo PV Solar												

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(1) Line No.	(2) PLANT UNIT	(3) Net Capability (MW)	(4) Net Generation (MWH)	(5) Capacity Factor	(6) Equivalent Availability Factor	(7) Net Output Factor	(8) Avg Net Heat Rate (BTU/KWH)	(9) Fuel Burned (Units)	(10) Fuel Heat Value (BTU/Unit)	(11) Fuel Burned (MMBTU)	(12) As Burned Fuel Cost ($)	(13) Fuel Cost per KWH (cents/KWH)	(14) Cost of Fuel ($/Unit)
1	Solar		551					N/A	N/A	N/A	N/A	N/A	N/A
2	Plant Unit Info	74.5	551	1.0%	3.2%	30.8%	N/A						
3	Sabal Palm PV Solar												
4	Solar		0					N/A	N/A	N/A	N/A	N/A	N/A
5	Plant Unit Info	0.0	0	N/A	N/A	N/A	N/A						
6	Sanford 4												
7	Gas		128,255				7,583	972,512	1,000,000	972,512	4,626,597	3.61	4.76
8	Plant Unit Info	1,192.0	128,255	14.5%	48.9%	26.4%	7,583			972,512	4,626,597	3.61	
9	Sanford 5												
10	Gas		237,840				7,122	1,693,879	1,000,000	1,693,879	8,096,428	3.40	4.78
11	Plant Unit Info	1,192.0	237,840	26.8%	55.4%	43.8%	7,122			1,693,879	8,096,428	3.40	
12	Scherer 4												
13	Coal		185,870				11,395	124,585	17,000,001	2,117,950	5,362,558	2.89	43.04
14	Plant Unit Info	626.0	185,870	39.9%	92.2%	39.9%	11,395			2,117,950	5,362,558	2.89	
15	Southfork PV Solar												
16	Solar		18,494					N/A	N/A	N/A	N/A	N/A	N/A
17	Plant Unit Info	74.5	18,494	33.4%	N/A	33.4%	N/A						
18	Space Coast												
19	Solar		1,626					N/A	N/A	N/A	N/A	N/A	N/A
20	Plant Unit Info	10.0	1,626	21.9%	N/A	21.9%	N/A						
21	St Lucie 1												
22	Nuclear		727,591				10,328	7,514,787	1,000,000	7,514,787	3,625,884	0.50	0.48
23	Plant Unit Info	1,003.0	727,591	97.5%	97.5%	97.5%	10,328			7,514,787	3,625,884	0.50	
24	St Lucie 2												
25	Nuclear		623,512				10,257	6,395,178	1,000,000	6,395,178	2,775,507	0.45	0.43
26	Plant Unit Info	859.6	623,512	97.5%	97.5%	97.5%	10,257			6,395,178	2,775,507	0.45	
27	Sunshine Gateway PV Solar												
28	Solar		15,387					N/A	N/A	N/A	N/A	N/A	N/A
29	Plant Unit Info	74.5	15,387	27.8%	N/A	27.8%	N/A						
30	Sweet Bay PV Solar												
31	Solar		15,004					N/A	N/A	N/A	N/A	N/A	N/A
32	Plant Unit Info	74.5	15,004	27.1%	N/A	27.1%	N/A						
33	Trailside PV Solar												
34	Solar		16,568					N/A	N/A	N/A	N/A	N/A	N/A
35	Plant Unit Info	74.5	16,568	29.9%	N/A	29.9%	N/A						
36	Turkey Point 3												
37	Nuclear		623,100				10,541	6,568,284	1,000,000	6,568,284	3,161,801	0.51	0.48
38	Plant Unit Info	859.0	623,100	97.5%	97.5%	97.5%	10,541			6,568,284	3,161,801	0.51	
39	Turkey Point 4												
40	Nuclear		629,647				10,432	6,568,480	1,000,000	6,568,480	3,790,670	0.60	0.58
41	Plant Unit Info	868.0	629,647	97.5%	97.5%	97.5%	10,432			6,568,480	3,790,670	0.60	
42	Turkey Point 5												
43	Light Oil		0					0	0	0	0	0.00	0.00

ESTIMATED FOR THE PERIOD OF: JANUARY 2021 THROUGH DECEMBER 2021

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.	PLANT UNIT	Net Capability (MW)	Net Generation (MWH)	Capacity Factor	Equivalent Availability Factor	Net Output Factor	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost ($)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel ($/Unit)
1	Gas		151,772				7,128	1,081,868	1,000,000	1,081,868	5,145,100	3.39	4.76
2	Plant Unit Info	1,294.0	151,772	15.8%	26.2%	48.9%	7,128			1,081,868	5,145,100	3.39	
3	Twin Lakes PV Solar												
4	Solar		16,364					N/A	N/A	N/A	N/A	N/A	N/A
5	Plant Unit Info	74.5	16,364	29.5%	N/A	29.5%	N/A						
6	Union Springs PV Solar												
7	Solar		16,413					N/A	N/A	N/A	N/A	N/A	N/A
8	Plant Unit Info	74.5	16,413	29.6%	N/A	29.6%	N/A						
9	WCEC 01												
10	Light Oil		0					0	0	0	0	0.00	0.00
11	Gas		663,141				6,734	4,465,701	1,000,000	4,465,701	21,189,203	3.20	4.74
12	Plant Unit Info	1,248.0	663,141	71.4%	93.7%	71.4%	6,734			4,465,701	21,189,203	3.20	
13	WCEC 02												
14	Light Oil		0					0	0	0	0	0.00	0.00
15	Gas		482,145				6,720	3,239,934	1,000,000	3,239,934	15,363,844	3.19	4.74
16	Plant Unit Info	1,248.0	482,145	51.9%	61.5%	76.7%	6,720			3,239,934	15,363,844	3.19	
17	WCEC 03												
18	Light Oil		0					0	0	0	0	0.00	0.00
19	Gas		529,718				6,697	3,547,389	1,000,000	3,547,389	16,835,588	3.18	4.75
20	Plant Unit Info	1,254.0	529,718	56.8%	60.4%	85.4%	6,697			3,547,389	16,835,588	3.18	
21	Wildflower PV Solar												
22	Solar		16,842					N/A	N/A	N/A	N/A	N/A	N/A
23	Plant Unit Info	74.5	16,842	30.4%	N/A	30.4%	N/A						
24	Willow PV Solar												
25	Solar		0					N/A	N/A	N/A	N/A	N/A	N/A
26	Plant Unit Info	0.0	0	N/A	N/A	N/A	N/A						
27	System Totals												
28	Plant Unit Info	28,576	9,360,109				7,509			70,281,486	214,383,826	2.29	
29													
30													
31													
32													
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ESTIMATED FOR THE PERIOD OF: JANUARY 2021 THROUGH DECEMBER 2021

(1) Line No.	(2) PLANT UNIT	(3) Net Capability (MW)	(4) Net Generation (MWH)	(5) Capacity Factor	(6) Equivalent Availability Factor	(7) Net Output Factor	(8) Avg Net Heat Rate (BTU/KWH)	(9) Fuel Burned (Units)	(10) Fuel Heat Value (BTU/Unit)	(11) Fuel Burned (MMBTU)	(12) As Burned Fuel Cost ($)	(13) Fuel Cost per KWH (cents/KWH)	(14) Cost of Fuel ($/Unit)
1	**Apr - 2021**												
2	Babcock PV Solar												
3	Solar		15,726					N/A	N/A	N/A	N/A	N/A	N/A
4	Plant Unit Info	74.5	15,726	29.3%	N/A	29.3%	N/A						
5	Babcock Preserve PV Solar												
6	Solar		16,562					N/A	N/A	N/A	N/A	N/A	N/A
7	Plant Unit Info	74.5	16,562	30.9%	N/A	30.9%	N/A						
8	Barefoot PV Solar												
9	Solar		16,349					N/A	N/A	N/A	N/A	N/A	N/A
10	Plant Unit Info	74.5	16,349	30.5%	N/A	30.5%	N/A						
11	Blue Cypress PV Solar												
12	Solar		16,808					N/A	N/A	N/A	N/A	N/A	N/A
13	Plant Unit Info	74.5	16,808	31.3%	N/A	31.3%	N/A						
14	Blue Heron PV Solar												
15	Solar		16,562					N/A	N/A	N/A	N/A	N/A	N/A
16	Plant Unit Info	74.5	16,562	30.9%	N/A	30.9%	N/A						
17	CCEC 3												
18	Light Oil		0					0	0	0	0	0.00	0.00
19	Gas		632,418				6,745	4,265,821	1,000,000	4,265,821	18,078,048	2.86	4.24
20	Plant Unit Info	1,308.0	632,418	67.2%	93.4%	67.2%	6,745			4,265,821	18,078,048	2.86	
21	Cattle Ranch PV Solar												
22	Solar		17,972					N/A	N/A	N/A	N/A	N/A	N/A
23	Plant Unit Info	74.5	17,972	33.5%	N/A	33.5%	N/A						
24	Citrus PV Solar												
25	Solar		15,795					N/A	N/A	N/A	N/A	N/A	N/A
26	Plant Unit Info	74.5	15,795	29.5%	N/A	29.5%	N/A						
27	Coral Farms PV Solar												
28	Solar		17,330					N/A	N/A	N/A	N/A	N/A	N/A
29	Plant Unit Info	74.5	17,330	32.3%	N/A	32.3%	N/A						
30	Desoto Solar												
31	Solar		4,930					N/A	N/A	N/A	N/A	N/A	N/A
32	Plant Unit Info	25.0	4,930	27.4%	N/A	27.4%	N/A						
33	Discovery PV Solar												
34	Solar		0					N/A	N/A	N/A	N/A	N/A	N/A
35	Plant Unit Info	0.0	0	N/A	N/A	N/A	N/A						
36	Egret PV Solar												
37	Solar		17,434					N/A	N/A	N/A	N/A	N/A	N/A
38	Plant Unit Info	74.5	17,434	32.5%	N/A	32.5%	N/A						
39	Fort Drum PV Solar												
40	Solar		0					N/A	N/A	N/A	N/A	N/A	N/A
41	Plant Unit Info	0.0	0	N/A	N/A	N/A	N/A						
42	Fort Myers 2												
43	Gas		710,471				7,233	5,138,642	1,000,000	5,138,642	21,778,166	3.07	4.24

ESTIMATED FOR THE PERIOD OF: JANUARY 2021 THROUGH DECEMBER 2021

(1) Line No.	(2) PLANT UNIT	(3) Net Capability (MW)	(4) Net Generation (MWH)	(5) Capacity Factor	(6) Equivalent Availability Factor	(7) Net Output Factor	(8) Avg Net Heat Rate (BTU/KWH)	(9) Fuel Burned (Units)	(10) Fuel Heat Value (BTU/Unit)	(11) Fuel Burned (MMBTU)	(12) As Burned Fuel Cost ($)	(13) Fuel Cost per KWH (cents/KWH)	(14) Cost of Fuel ($/Unit)
1	Plant Unit Info	1,730.0	710,471	57.0%	93.8%	57.0%	7,233			5,138,642	21,778,166	3.07	
2	Fort Myers 3A												
3	Light Oil		0					0	0	0	0	0.00	0.00
4	Gas		0					0	0	0	0	0.00	0.00
5	Plant Unit Info	164.0	0	N/A	93.7%	N/A	N/A						
6	Fort Myers 3B												
7	Light Oil		0					0	0	0	0	0.00	0.00
8	Gas		0					0	0	0	0	0.00	0.00
9	Plant Unit Info	168.0	0	N/A	93.7%	N/A	N/A						
10	Fort Myers 3C												
11	Light Oil		0					0	0	0	0	0.00	0.00
12	Gas		3,038				10,529	31,987	1,000,000	31,987	135,985	4.48	4.25
13	Plant Unit Info	219.0	3,038	1.9%	93.7%	1.9%	10,529			31,987	135,985	4.48	
14	Fort Myers 3D												
15	Light Oil		0					0	0	0	0	0.00	0.00
16	Gas		2,025				10,530	21,324	1,000,000	21,324	90,558	4.47	4.25
17	Plant Unit Info	219.0	2,025	1.3%	93.7%	1.3%	10,530			21,324	90,558	4.47	
18	Echo River PV Solar												
19	Solar		19,341					N/A	N/A	N/A	N/A	N/A	N/A
20	Plant Unit Info	74.5	19,341	36.1%	N/A	36.1%	N/A						
21	Hammock PV Solar												
22	Solar		17,146					N/A	N/A	N/A	N/A	N/A	N/A
23	Plant Unit Info	74.5	17,146	32.0%	N/A	32.0%	N/A						
24	Hibiscus PV Solar												
25	Solar		16,258					N/A	N/A	N/A	N/A	N/A	N/A
26	Plant Unit Info	74.5	16,258	30.3%	N/A	30.3%	N/A						
27	Horizon PV Solar												
28	Solar		17,428					N/A	N/A	N/A	N/A	N/A	N/A
29	Plant Unit Info	74.5	17,428	32.5%	N/A	32.5%	N/A						
30	Indian River PV Solar												
31	Solar		16,798					N/A	N/A	N/A	N/A	N/A	N/A
32	Plant Unit Info	74.5	16,798	31.3%	N/A	31.3%	N/A						
33	Indiantown												
34	Plant Unit Info	0.0	0	N/A	N/A	N/A	N/A						
35	Interstate PV Solar												
36	Solar		16,464					N/A	N/A	N/A	N/A	N/A	N/A
37	Plant Unit Info	74.5	16,464	30.7%	N/A	30.7%	N/A						
38	Lakeside PV Solar												
39	Solar		16,353					N/A	N/A	N/A	N/A	N/A	N/A
40	Plant Unit Info	74.5	16,353	30.5%	N/A	30.5%	N/A						
41	Lauderdale 6A												
42	Light Oil		0					0	0	0	0	0.00	0.00
43	Gas		3,003				10,572	31,748	1,000,000	31,748	134,970	4.49	4.25

ESTIMATED FOR THE PERIOD OF: JANUARY 2021 THROUGH DECEMBER 2021

(1) Line No.	(2) PLANT UNIT	(3) Net Capability (MW)	(4) Net Generation (MWH)	(5) Capacity Factor	(6) Equivalent Availability Factor	(7) Net Output Factor	(8) Avg Net Heat Rate (BTU/KWH)	(9) Fuel Burned (Units)	(10) Fuel Heat Value (BTU/Unit)	(11) Fuel Burned (MMBTU)	(12) As Burned Fuel Cost ($)	(13) Fuel Cost per KWH (cents/KWH)	(14) Cost of Fuel ($/Unit)
1	Plant Unit Info	216.0	3,003	1.9%	94.0%	1.9%	10,572			31,748	134,970	4.49	
2	Lauderdale 6B												
3	Light Oil		0					0	0	0	0	0.00	0.00
4	Gas		4,004				10,572	42,331	1,000,000	42,331	179,961	4.49	4.25
5	Plant Unit Info	216.0	4,004	2.6%	94.0%	2.6%	10,572			42,331	179,961	4.49	
6	Lauderdale 6C												
7	Light Oil		0					0	0	0	0	0.00	0.00
8	Gas		0					0	0	0	0	0.00	0.00
9	Plant Unit Info	216.0	0	N/A	94.0%	N/A	N/A						
10	Lauderdale 6D												
11	Light Oil		0					0	0	0	0	0.00	0.00
12	Gas		0					0	0	0	0	0.00	0.00
13	Plant Unit Info	216.0	0	N/A	94.0%	N/A	N/A						
14	Lauderdale 6E												
15	Light Oil		0					0	0	0	0	0.00	0.00
16	Gas		0					0	0	0	0	0.00	0.00
17	Plant Unit Info	216.0	0	N/A	94.0%	N/A	N/A						
18	Loggerhead PV Solar												
19	Solar		16,886					N/A	N/A	N/A	N/A	N/A	N/A
20	Plant Unit Info	74.5	16,886	31.5%	N/A	31.5%	N/A						
21	Magnolia PV Solar												
22	Solar		17,560					N/A	N/A	N/A	N/A	N/A	N/A
23	Plant Unit Info	74.5	17,560	32.7%	N/A	32.7%	N/A						
24	Manatee 1												
25	Heavy Oil		-					0	0	0	0	0.00	0.00
26	Gas		6,954				14,380	99,997	1,000,000	99,997	415,908	5.98	4.16
27	Plant Unit Info	789.0	6,954	1.2%	94.1%	1.2%	14,380			99,997	415,908	5.98	
28	Manatee 2												
29	Heavy Oil		191				15,546	464	6,399,948	2,969	31,804	16.65	68.56
30	Gas		2,153				15,547	33,472	1,000,000	33,472	139,864	6.50	4.18
31	Plant Unit Info	789.0	2,344	0.4%	94.1%	0.4%	15,547			36,441	171,668	7.32	
32	Manatee 3												
33	Gas		465,504				7,143	3,325,267	1,000,000	3,325,267	13,827,558	2.97	4.16
34	Plant Unit Info	1,223.0	465,504	52.9%	93.9%	52.9%	7,143			3,325,267	13,827,558	2.97	
35	Manatee PV Solar												
36	Solar		15,985					N/A	N/A	N/A	N/A	N/A	N/A
37	Plant Unit Info	74.5	15,985	29.8%	N/A	29.8%	N/A						
38	Martin 3												
39	Gas		165,821				7,573	1,255,772	1,000,000	1,255,772	5,241,029	3.16	4.17
40	Plant Unit Info	464.0	165,821	49.6%	93.9%	49.6%	7,573			1,255,772	5,241,029	3.16	
41	Martin 4												
42	Gas		5,954				9,253	55,090	1,000,000	55,090	230,891	3.88	4.19
43	Plant Unit Info	464.0	5,954	1.8%	70.6%	2.3%	9,253			55,090	230,891	3.88	

ESTIMATED FOR THE PERIOD OF: JANUARY 2021 THROUGH DECEMBER 2021

(1) Line No.	(2) PLANT UNIT	(3) Net Capability (MW)	(4) Net Generation (MWH)	(5) Capacity Factor	(6) Equivalent Availability Factor	(7) Net Output Factor	(8) Avg Net Heat Rate (BTU/KWH)	(9) Fuel Burned (Units)	(10) Fuel Heat Value (BTU/Unit)	(11) Fuel Burned (MMBTU)	(12) As Burned Fuel Cost ($)	(13) Fuel Cost per KWH (cents/KWH)	(14) Cost of Fuel ($/Unit)
1	Martin 8 Solar												
2	Solar		14,310					N/A	N/A	N/A	N/A	N/A	N/A
3	Plant Unit Info	75.0	14,310	26.5%	N/A	26.5%	N/A						
4	Martin 8												
5	Light Oil		0					0	0	0	0	0.00	0.00
6	Gas		304,716				7,519	2,291,279	1,000,000	2,291,279	9,569,322	3.14	4.18
7	Plant Unit Info	1,218.0	304,716	34.8%	81.8%	38.7%	7,519			2,291,279	9,569,322	3.14	
8	Miami-Dade PV Solar												
9	Solar		16,134					N/A	N/A	N/A	N/A	N/A	N/A
10	Plant Unit Info	74.5	16,134	30.1%	N/A	30.1%	N/A						
11	Nassau PV Solar												
12	Solar		17,352					N/A	N/A	N/A	N/A	N/A	N/A
13	Plant Unit Info	74.5	17,352	32.4%	N/A	32.4%	N/A						
14	Northern Preserve PV Solar												
15	Solar		14,395					N/A	N/A	N/A	N/A	N/A	N/A
16	Plant Unit Info	74.5	14,395	26.8%	N/A	26.8%	N/A						
17	Okeechobee 1												
18	Light Oil		0					0	0	0	0	0.00	0.00
19	Gas		1,036,480				6,280	6,508,851	1,000,000	6,508,851	27,395,036	2.64	4.21
20	Plant Unit Info	1,618.0	1,036,480	89.0%	93.0%	89.0%	6,280			6,508,851	27,395,036	2.64	
21	Okeechobee PV Solar												
22	Solar		16,780					N/A	N/A	N/A	N/A	N/A	N/A
23	Plant Unit Info	74.5	16,780	31.3%	N/A	31.3%	N/A						
24	Orange Blossom PV Solar												
25	Solar		0					N/A	N/A	N/A	N/A	N/A	N/A
26	Plant Unit Info	0.0	0	N/A	N/A	N/A	N/A						
27	Palm Bay PV Solar												
28	Solar		16,353					N/A	N/A	N/A	N/A	N/A	N/A
29	Plant Unit Info	74.5	16,353	30.5%	N/A	30.5%	N/A						
30	PEEC												
31	Gas		532,075				6,381	3,395,138	1,000,000	3,395,138	14,393,718	2.71	4.24
32	Plant Unit Info	1,254.0	532,075	58.9%	59.6%	88.4%	6,381			3,395,138	14,393,718	2.71	
33	Pelican PV Solar												
34	Solar		16,329					N/A	N/A	N/A	N/A	N/A	N/A
35	Plant Unit Info	74.5	16,329	30.4%	N/A	30.4%	N/A						
36	Pioneer Trail PV Solar												
37	Solar		16,141					N/A	N/A	N/A	N/A	N/A	N/A
38	Plant Unit Info	74.5	16,141	30.1%	N/A	30.1%	N/A						
39	Riviera 5												
40	Light Oil		0					0	0	0	0	0.00	0.00
41	Gas		55,795				6,613	368,975	1,000,000	368,975	1,552,974	2.78	4.21
42	Plant Unit Info	1,308.0	55,795	0.1%	0.1%	88.9%	6,613			368,975	1,552,974	2.78	
43	Rodeo PV Solar												

ESTIMATED FOR THE PERIOD OF: JANUARY 2021 THROUGH DECEMBER 2021

(1) Line No.	(2) PLANT UNIT	(3) Net Capability (MW)	(4) Net Generation (MWH)	(5) Capacity Factor	(6) Equivalent Availability Factor	(7) Net Output Factor	(8) Avg Net Heat Rate (BTU/KWH)	(9) Fuel Burned (Units)	(10) Fuel Heat Value (BTU/Unit)	(11) Fuel Burned (MMBTU)	(12) As Burned Fuel Cost ($)	(13) Fuel Cost per KWH (cents/KWH)	(14) Cost of Fuel ($/Unit)
1	Solar		18,251					N/A	N/A	N/A	N/A	N/A	N/A
2	Plant Unit Info	74.5	18,251	34.0%	N/A	34.0%	N/A						
3	Sabal Palm PV Solar												
4	Solar		0					N/A	N/A	N/A	N/A	N/A	N/A
5	Plant Unit Info	0.0	0	N/A	N/A	N/A	N/A						
6	Sanford 4												
7	Gas		143,914				7,743	1,114,343	1,000,000	1,114,343	4,724,910	3.28	4.24
8	Plant Unit Info	1,147.0	143,914	17.4%	94.1%	17.4%	7,743			1,114,343	4,724,910	3.28	
9	Sanford 5												
10	Gas		404,295				7,135	2,884,486	1,000,000	2,884,486	12,225,980	3.02	4.24
11	Plant Unit Info	1,147.0	404,295	49.0%	87.4%	52.5%	7,135			2,884,486	12,225,980	3.02	
12	Scherer 4												
13	Coal		178,413				11,427	119,921	16,999,999	2,038,652	5,153,610	2.89	42.98
14	Plant Unit Info	636.0	178,413	39.0%	92.2%	39.0%	11,427			2,038,652	5,153,610	2.89	
15	Southfork PV Solar												
16	Solar		19,947					N/A	N/A	N/A	N/A	N/A	N/A
17	Plant Unit Info	74.5	19,947	37.2%	N/A	37.2%	N/A						
18	Space Coast												
19	Solar		1,682					N/A	N/A	N/A	N/A	N/A	N/A
20	Plant Unit Info	10.0	1,682	23.4%	N/A	23.4%	N/A						
21	St Lucie 1												
22	Nuclear		206,589				10,560	2,181,563	1,000,000	2,181,563	1,052,604	0.51	0.48
23	Plant Unit Info	981.0	206,589	29.3%	29.2%	97.5%	10,560			2,181,563	1,052,604	0.51	
24	St Lucie 2												
25	Nuclear		589,637				10,496	6,188,655	1,000,000	6,188,655	2,685,876	0.46	0.43
26	Plant Unit Info	840.0	589,637	97.5%	97.5%	97.5%	10,496			6,188,655	2,685,876	0.46	
27	Sunshine Gateway PV Solar												
28	Solar		16,228					N/A	N/A	N/A	N/A	N/A	N/A
29	Plant Unit Info	74.5	16,228	30.3%	N/A	30.3%	N/A						
30	Sweet Bay PV Solar												
31	Solar		14,791					N/A	N/A	N/A	N/A	N/A	N/A
32	Plant Unit Info	74.5	14,791	27.6%	N/A	27.6%	N/A						
33	Trailside PV Solar												
34	Solar		17,707					N/A	N/A	N/A	N/A	N/A	N/A
35	Plant Unit Info	74.5	17,707	33.0%	N/A	33.0%	N/A						
36	Turkey Point 3												
37	Nuclear		587,592				10,818	6,356,806	1,000,000	6,356,806	3,060,001	0.52	0.48
38	Plant Unit Info	837.0	587,592	97.5%	97.5%	97.5%	10,818			6,356,806	3,060,001	0.52	
39	Turkey Point 4												
40	Nuclear		590,400				10,767	6,356,778	1,000,000	6,356,778	3,668,497	0.62	0.58
41	Plant Unit Info	841.0	590,400	97.5%	97.5%	97.5%	10,767			6,356,778	3,668,497	0.62	
42	Turkey Point 5												
43	Light Oil		0					0	0	0	0	0.00	0.00

ESTIMATED FOR THE PERIOD OF: JANUARY 2021 THROUGH DECEMBER 2021

(1) Line No.	(2) PLANT UNIT	(3) Net Capability (MW)	(4) Net Generation (MWH)	(5) Capacity Factor	(6) Equivalent Availability Factor	(7) Net Output Factor	(8) Avg Net Heat Rate (BTU/KWH)	(9) Fuel Burned (Units)	(10) Fuel Heat Value (BTU/Unit)	(11) Fuel Burned (MMBTU)	(12) As Burned Fuel Cost ($)	(13) Fuel Cost per KWH (cents/KWH)	(14) Cost of Fuel ($/Unit)
1	Gas		252,076				7,595	1,914,404	1,000,000	1,914,404	8,117,752	3.22	4.24
2	Plant Unit Info	1,256.0	252,076	27.9%	93.9%	27.9%	7,595			1,914,404	8,117,752	3.22	
3	Twin Lakes PV Solar												
4	Solar		17,489					N/A	N/A	N/A	N/A	N/A	N/A
5	Plant Unit Info	74.5	17,489	32.6%	N/A	32.6%	N/A						
6	Union Springs PV Solar												
7	Solar		17,542					N/A	N/A	N/A	N/A	N/A	N/A
8	Plant Unit Info	74.5	17,542	32.7%	N/A	32.7%	N/A						
9	WCEC 01												
10	Light Oil		0					0	0	0	0	0.00	0.00
11	Gas		708,273				6,725	4,763,481	1,000,000	4,763,481	19,809,033	2.80	4.16
12	Plant Unit Info	1,223.0	708,273	80.4%	93.7%	80.4%	6,725			4,763,481	19,809,033	2.80	
13	WCEC 02												
14	Light Oil		0					0	0	0	0	0.00	0.00
15	Gas		735,725				6,687	4,919,799	1,000,000	4,919,799	20,459,241	2.78	4.16
16	Plant Unit Info	1,223.0	735,725	83.6%	93.7%	83.6%	6,687			4,919,799	20,459,241	2.78	
17	WCEC 03												
18	Light Oil		0					0	0	0	0	0.00	0.00
19	Gas		701,130				6,707	4,702,304	1,000,000	4,702,304	19,554,727	2.79	4.16
20	Plant Unit Info	1,228.0	701,130	79.3%	88.2%	84.1%	6,707			4,702,304	19,554,727	2.79	
21	Wildflower PV Solar												
22	Solar		17,225					N/A	N/A	N/A	N/A	N/A	N/A
23	Plant Unit Info	74.5	17,225	32.1%	N/A	32.1%	N/A						
24	Willow PV Solar												
25	Solar		0					N/A	N/A	N/A	N/A	N/A	N/A
26	Plant Unit Info	0.0	0	N/A	N/A	N/A	N/A						
27	System Totals												
28	Plant Unit Info	28,017	9,622,989				7,304			70,289,934	213,708,021	2.22	
29													
30													
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(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.	PLANT UNIT	Net Capability (MW)	Net Generation (MWH)	Capacity Factor	Equivalent Availability Factor	Net Output Factor	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost ($)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel ($/Unit)
1	**May - 2021**												
2	Babcock PV Solar												
3	Solar		16,053					N/A	N/A	N/A	N/A	N/A	N/A
4	Plant Unit Info	74.5	16,053	29.0%	N/A	29.0%	N/A						
5	Babcock Preserve PV Solar												
6	Solar		17,144					N/A	N/A	N/A	N/A	N/A	N/A
7	Plant Unit Info	74.5	17,144	30.9%	N/A	30.9%	N/A						
8	Barefoot PV Solar												
9	Solar		16,854					N/A	N/A	N/A	N/A	N/A	N/A
10	Plant Unit Info	74.5	16,854	30.4%	N/A	30.4%	N/A						
11	Blue Cypress PV Solar												
12	Solar		17,300					N/A	N/A	N/A	N/A	N/A	N/A
13	Plant Unit Info	74.5	17,300	31.2%	N/A	31.2%	N/A						
14	Blue Heron PV Solar												
15	Solar		17,144					N/A	N/A	N/A	N/A	N/A	N/A
16	Plant Unit Info	74.5	17,144	30.9%	N/A	30.9%	N/A						
17	CCEC 3												
18	Light Oil		0					0	0	0	0	0.00	0.00
19	Gas		626,120				6,762	4,233,704	1,000,000	4,233,704	17,106,134	2.73	4.04
20	Plant Unit Info	1,308.0	626,120	64.3%	93.4%	64.3%	6,762			4,233,704	17,106,134	2.73	
21	Cattle Ranch PV Solar												
22	Solar		19,198					N/A	N/A	N/A	N/A	N/A	N/A
23	Plant Unit Info	74.5	19,198	34.6%	N/A	34.6%	N/A						
24	Citrus PV Solar												
25	Solar		16,286					N/A	N/A	N/A	N/A	N/A	N/A
26	Plant Unit Info	74.5	16,286	29.4%	N/A	29.4%	N/A						
27	Coral Farms PV Solar												
28	Solar		18,438					N/A	N/A	N/A	N/A	N/A	N/A
29	Plant Unit Info	74.5	18,438	33.3%	N/A	33.3%	N/A						
30	Desoto Solar												
31	Solar		5,080					N/A	N/A	N/A	N/A	N/A	N/A
32	Plant Unit Info	25.0	5,080	27.3%	N/A	27.3%	N/A						
33	Discovery PV Solar												
34	Solar		495					N/A	N/A	N/A	N/A	N/A	N/A
35	Plant Unit Info	74.5	495	0.9%	3.2%	27.7%	N/A						
36	Egret PV Solar												
37	Solar		18,623					N/A	N/A	N/A	N/A	N/A	N/A
38	Plant Unit Info	74.5	18,623	33.6%	N/A	33.6%	N/A						
39	Fort Drum PV Solar												
40	Solar		0					N/A	N/A	N/A	N/A	N/A	N/A
41	Plant Unit Info	0.0	0	N/A	N/A	N/A	N/A						
42	Fort Myers 2												
43	Gas		678,860				7,236	4,912,402	1,000,000	4,912,402	19,846,505	2.92	4.04

ESTIMATED FOR THE PERIOD OF: JANUARY 2021 THROUGH DECEMBER 2021

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.	PLANT UNIT	Net Capability (MW)	Net Generation (MWH)	Capacity Factor	Equivalent Availability Factor	Net Output Factor	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost ($)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel ($/Unit)
1	Plant Unit Info	1,730.0	678,860	52.7%	93.8%	52.7%	7,236			4,912,402	19,846,505	2.92	
2	Fort Myers 3A												
3	Light Oil		0					0	0	0	0	0.00	0.00
4	Gas		0					0	0	0	0	0.00	0.00
5	Plant Unit Info	164.0	0	N/A	93.7%	N/A	N/A						
6	Fort Myers 3B												
7	Light Oil		0					0	0	0	0	0.00	0.00
8	Gas		0					0	0	0	0	0.00	0.00
9	Plant Unit Info	168.0	0	N/A	93.7%	N/A	N/A						
10	Fort Myers 3C												
11	Light Oil		0					0	0	0	0	0.00	0.00
12	Gas		1,013				10,525	10,662	1,000,000	10,662	42,962	4.24	4.03
13	Plant Unit Info	219.0	1,013	0.6%	93.7%	0.6%	10,525			10,662	42,962	4.24	
14	Fort Myers 3D												
15	Light Oil		0					0	0	0	0	0.00	0.00
16	Gas		1,013				10,525	10,662	1,000,000	10,662	42,962	4.24	4.03
17	Plant Unit Info	219.0	1,013	0.6%	93.7%	0.6%	10,525			10,662	42,962	4.24	
18	Echo River PV Solar												
19	Solar		21,384					N/A	N/A	N/A	N/A	N/A	N/A
20	Plant Unit Info	74.5	21,384	38.6%	N/A	38.6%	N/A						
21	Hammock PV Solar												
22	Solar		17,551					N/A	N/A	N/A	N/A	N/A	N/A
23	Plant Unit Info	74.5	17,551	31.7%	N/A	31.7%	N/A						
24	Hibiscus PV Solar												
25	Solar		17,041					N/A	N/A	N/A	N/A	N/A	N/A
26	Plant Unit Info	74.5	17,041	30.8%	N/A	30.7%	N/A						
27	Horizon PV Solar												
28	Solar		18,629					N/A	N/A	N/A	N/A	N/A	N/A
29	Plant Unit Info	74.5	18,629	33.6%	N/A	33.6%	N/A						
30	Indian River PV Solar												
31	Solar		17,289					N/A	N/A	N/A	N/A	N/A	N/A
32	Plant Unit Info	74.5	17,289	31.2%	N/A	31.2%	N/A						
33	Indiantown												
34	Plant Unit Info	0.0	0	N/A	N/A	N/A	N/A						
35	Interstate PV Solar												
36	Solar		16,892					N/A	N/A	N/A	N/A	N/A	N/A
37	Plant Unit Info	74.5	16,892	30.5%	N/A	30.5%	N/A						
38	Lakeside PV Solar												
39	Solar		16,928					N/A	N/A	N/A	N/A	N/A	N/A
40	Plant Unit Info	74.5	16,928	30.5%	N/A	30.5%	N/A						
41	Lauderdale 6A												
42	Light Oil		0					0	0	0	0	0.00	0.00
43	Gas		2,002				10,572	21,165	1,000,000	21,165	85,668	4.28	4.05

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(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.	PLANT UNIT	Net Capability (MW)	Net Generation (MWH)	Capacity Factor	Equivalent Availability Factor	Net Output Factor	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost ($)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel ($/Unit)
1	Plant Unit Info	216.0	2,002	1.3%	94.0%	1.3%	10,572			21,165	85,668	4.28	
2	Lauderdale 6B												
3	Light Oil		0					0	0	0	0	0.00	0.00
4	Gas		1,001				10,572	10,583	1,000,000	10,583	42,642	4.26	4.03
5	Plant Unit Info	216.0	1,001	0.6%	94.0%	0.6%	10,572			10,583	42,642	4.26	
6	Lauderdale 6C												
7	Light Oil		0					0	0	0	0	0.00	0.00
8	Gas		0					0	0	0	0	0.00	0.00
9	Plant Unit Info	216.0	0	N/A	94.0%	N/A	N/A						
10	Lauderdale 6D												
11	Light Oil		0					0	0	0	0	0.00	0.00
12	Gas		0					0	0	0	0	0.00	0.00
13	Plant Unit Info	216.0	0	N/A	94.0%	N/A	N/A						
14	Lauderdale 6E												
15	Light Oil		0					0	0	0	0	0.00	0.00
16	Gas		0					0	0	0	0	0.00	0.00
17	Plant Unit Info	216.0	0	N/A	94.0%	N/A	N/A						
18	Loggerhead PV Solar												
19	Solar		17,304					N/A	N/A	N/A	N/A	N/A	N/A
20	Plant Unit Info	74.5	17,304	31.2%	N/A	31.2%	N/A						
21	Magnolia PV Solar												
22	Solar		18,758					N/A	N/A	N/A	N/A	N/A	N/A
23	Plant Unit Info	74.5	18,758	33.8%	N/A	33.8%	N/A						
24	Manatee 1												
25	Heavy Oil		-					0	0	0	0	0.00	0.00
26	Gas		1,861				16,938	31,522	1,000,000	31,522	124,721	6.70	3.96
27	Plant Unit Info	789.0	1,861	0.3%	94.1%	0.3%	16,938			31,522	124,721	6.70	
28	Manatee 2												
29	Heavy Oil		-					0	0	0	0	0.00	0.00
30	Gas		0					0	0	0	0	0.00	0.00
31	Plant Unit Info	789.0	0	N/A	94.1%	N/A	N/A						
32	Manatee 3												
33	Gas		339,847				7,411	2,518,655	1,000,000	2,518,655	9,969,526	2.93	3.96
34	Plant Unit Info	1,223.0	339,847	37.4%	93.9%	37.4%	7,411			2,518,655	9,969,526	2.93	
35	Manatee PV Solar												
36	Solar		16,600					N/A	N/A	N/A	N/A	N/A	N/A
37	Plant Unit Info	74.5	16,600	30.0%	N/A	30.0%	N/A						
38	Martin 3												
39	Gas		163,432				7,525	1,229,794	1,000,000	1,229,794	4,876,664	2.98	3.97
40	Plant Unit Info	464.0	163,432	47.3%	93.9%	47.3%	7,525			1,229,794	4,876,664	2.98	
41	Martin 4												
42	Gas		0					0	0	0	0	0.00	0.00
43	Plant Unit Info	464.0	0	N/A	N/A	N/A	N/A						

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(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.	PLANT UNIT	Net Capability (MW)	Net Generation (MWH)	Capacity Factor	Equivalent Availability Factor	Net Output Factor	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost ($)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel ($/Unit)
1	Martin 8 Solar												
2	Solar		14,074					N/A	N/A	N/A	N/A	N/A	N/A
3	Plant Unit Info	75.0	14,074	25.2%	N/A	25.2%	N/A						
4	Martin 8												
5	Light Oil		0					0	0	0	0	0.00	0.00
6	Gas		215,983				7,595	1,640,316	1,000,000	1,640,316	6,509,537	3.01	3.97
7	Plant Unit Info	1,218.0	215,983	23.8%	93.5%	23.8%	7,595			1,640,316	6,509,537	3.01	
8	Miami-Dade PV Solar												
9	Solar		16,355					N/A	N/A	N/A	N/A	N/A	N/A
10	Plant Unit Info	74.5	16,355	29.5%	N/A	29.5%	N/A						
11	Nassau PV Solar												
12	Solar		18,536					N/A	N/A	N/A	N/A	N/A	N/A
13	Plant Unit Info	74.5	18,536	33.4%	N/A	33.4%	N/A						
14	Northern Preserve PV Solar												
15	Solar		14,901					N/A	N/A	N/A	N/A	N/A	N/A
16	Plant Unit Info	74.5	14,901	26.9%	N/A	26.9%	N/A						
17	Okeechobee 1												
18	Light Oil		0					0	0	0	0	0.00	0.00
19	Gas		1,073,966				6,278	6,742,323	1,000,000	6,742,323	27,002,520	2.51	4.00
20	Plant Unit Info	1,618.0	1,073,966	89.2%	93.0%	89.2%	6,278			6,742,323	27,002,520	2.51	
21	Okeechobee PV Solar												
22	Solar		17,667					N/A	N/A	N/A	N/A	N/A	N/A
23	Plant Unit Info	74.5	17,667	31.9%	N/A	31.9%	N/A						
24	Orange Blossom PV Solar												
25	Solar		0					N/A	N/A	N/A	N/A	N/A	N/A
26	Plant Unit Info	0.0	0	N/A	N/A	N/A	N/A						
27	Palm Bay PV Solar												
28	Solar		16,928					N/A	N/A	N/A	N/A	N/A	N/A
29	Plant Unit Info	74.5	16,928	30.5%	N/A	30.5%	N/A						
30	PEEC												
31	Gas		825,488				6,362	5,251,570	1,000,000	5,251,570	21,215,600	2.57	4.04
32	Plant Unit Info	1,254.0	825,488	88.5%	93.0%	88.5%	6,362			5,251,570	21,215,600	2.57	
33	Pelican PV Solar												
34	Solar		16,903					N/A	N/A	N/A	N/A	N/A	N/A
35	Plant Unit Info	74.5	16,903	30.5%	N/A	30.5%	N/A						
36	Pioneer Trail PV Solar												
37	Solar		16,868					N/A	N/A	N/A	N/A	N/A	N/A
38	Plant Unit Info	74.5	16,868	30.4%	N/A	30.4%	N/A						
39	Riviera 5												
40	Light Oil		0					0	0	0	0	0.00	0.00
41	Gas		682,936				6,747	4,607,797	1,000,000	4,607,797	18,453,897	2.70	4.00
42	Plant Unit Info	1,308.0	682,936	70.2%	93.4%	70.2%	6,747			4,607,797	18,453,897	2.70	
43	Rodeo PV Solar												

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(1) Line No.	(2) PLANT UNIT	(3) Net Capability (MW)	(4) Net Generation (MWH)	(5) Capacity Factor	(6) Equivalent Availability Factor	(7) Net Output Factor	(8) Avg Net Heat Rate (BTU/KWH)	(9) Fuel Burned (Units)	(10) Fuel Heat Value (BTU/Unit)	(11) Fuel Burned (MMBTU)	(12) As Burned Fuel Cost ($)	(13) Fuel Cost per KWH (cents/KWH)	(14) Cost of Fuel ($/Unit)
1	Solar		19,496					N/A	N/A	N/A	N/A	N/A	N/A
2	Plant Unit Info	74.5	19,496	35.2%	N/A	35.2%	N/A						
3	Sabal Palm PV Solar												
4	Solar		16,921					N/A	N/A	N/A	N/A	N/A	N/A
5	Plant Unit Info	74.5	16,921	30.5%	N/A	30.5%	N/A						
6	Sanford 4												
7	Gas		402,124				7,237	2,909,971	1,000,000	2,909,971	11,755,768	2.92	4.04
8	Plant Unit Info	1,147.0	402,124	47.1%	94.1%	47.1%	7,237			2,909,971	11,755,768	2.92	
9	Sanford 5												
10	Gas		441,052				7,116	3,138,547	1,000,000	3,138,547	12,679,446	2.87	4.04
11	Plant Unit Info	1,147.0	441,052	51.7%	94.1%	51.7%	7,116			3,138,547	12,679,446	2.87	
12	Scherer 4												
13	Coal		180,562				11,460	121,719	17,000,000	2,069,231	5,219,720	2.89	42.88
14	Plant Unit Info	636.0	180,562	38.2%	92.2%	38.2%	11,460			2,069,231	5,219,720	2.89	
15	Southfork PV Solar												
16	Solar		21,623					N/A	N/A	N/A	N/A	N/A	N/A
17	Plant Unit Info	74.5	21,623	39.0%	N/A	39.0%	N/A						
18	Space Coast												
19	Solar		1,690					N/A	N/A	N/A	N/A	N/A	N/A
20	Plant Unit Info	10.0	1,690	22.7%	N/A	22.7%	N/A						
21	St Lucie 1												
22	Nuclear		413,178				10,560	4,363,128	1,000,000	4,363,128	2,045,434	0.50	0.47
23	Plant Unit Info	981.0	413,178	56.6%	56.6%	97.5%	10,560			4,363,128	2,045,434	0.50	
24	St Lucie 2												
25	Nuclear		609,292				10,496	6,394,944	1,000,000	6,394,944	2,775,405	0.46	0.43
26	Plant Unit Info	840.0	609,292	97.5%	97.5%	97.5%	10,496			6,394,944	2,775,405	0.46	
27	Sunshine Gateway PV Solar												
28	Solar		17,595					N/A	N/A	N/A	N/A	N/A	N/A
29	Plant Unit Info	74.5	17,595	31.7%	N/A	31.7%	N/A						
30	Sweet Bay PV Solar												
31	Solar		15,082					N/A	N/A	N/A	N/A	N/A	N/A
32	Plant Unit Info	74.5	15,082	27.2%	N/A	27.2%	N/A						
33	Trailside PV Solar												
34	Solar		18,915					N/A	N/A	N/A	N/A	N/A	N/A
35	Plant Unit Info	74.5	18,915	34.1%	N/A	34.1%	N/A						
36	Turkey Point 3												
37	Nuclear		607,178				10,818	6,568,699	1,000,000	6,568,699	3,162,001	0.52	0.48
38	Plant Unit Info	837.0	607,178	97.5%	97.5%	97.5%	10,818			6,568,699	3,162,001	0.52	
39	Turkey Point 4												
40	Nuclear		610,080				10,767	6,568,671	1,000,000	6,568,671	3,790,780	0.62	0.58
41	Plant Unit Info	841.0	610,080	97.5%	97.5%	97.5%	10,767			6,568,671	3,790,780	0.62	
42	Turkey Point 5												
43	Light Oil		0					0	0	0	0	0.00	0.00

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(1) Line No.	(2) PLANT UNIT	(3) Net Capability (MW)	(4) Net Generation (MWH)	(5) Capacity Factor	(6) Equivalent Availability Factor	(7) Net Output Factor	(8) Avg Net Heat Rate (BTU/KWH)	(9) Fuel Burned (Units)	(10) Fuel Heat Value (BTU/Unit)	(11) Fuel Burned (MMBTU)	(12) As Burned Fuel Cost ($)	(13) Fuel Cost per KWH (cents/KWH)	(14) Cost of Fuel ($/Unit)
1	Gas		284,038				7,338	2,084,245	1,000,000	2,084,245	8,426,419	2.97	4.04
2	Plant Unit Info	1,256.0	284,038	30.4%	93.9%	30.4%	7,338			2,084,245	8,426,419	2.97	
3	Twin Lakes PV Solar												
4	Solar		18,682					N/A	N/A	N/A	N/A	N/A	N/A
5	Plant Unit Info	74.5	18,682	33.7%	N/A	33.7%	N/A						
6	Union Springs PV Solar												
7	Solar		18,739					N/A	N/A	N/A	N/A	N/A	N/A
8	Plant Unit Info	74.5	18,739	33.8%	N/A	33.8%	N/A						
9	WCEC 01												
10	Light Oil		0					0	0	0	0	0.00	0.00
11	Gas		719,922				6,721	4,838,689	1,000,000	4,838,689	19,149,280	2.66	3.96
12	Plant Unit Info	1,223.0	719,922	79.1%	93.7%	79.1%	6,721			4,838,689	19,149,280	2.66	
13	WCEC 02												
14	Light Oil		0					0	0	0	0	0.00	0.00
15	Gas		733,767				6,704	4,919,466	1,000,000	4,919,466	19,468,821	2.65	3.96
16	Plant Unit Info	1,223.0	733,767	80.6%	93.7%	80.6%	6,704			4,919,466	19,468,821	2.65	
17	WCEC 03												
18	Light Oil		0					0	0	0	0	0.00	0.00
19	Gas		766,739				6,700	5,137,155	1,000,000	5,137,155	20,330,141	2.65	3.96
20	Plant Unit Info	1,228.0	766,739	83.9%	93.7%	83.9%	6,700			5,137,155	20,330,141	2.65	
21	Wildflower PV Solar												
22	Solar		17,745					N/A	N/A	N/A	N/A	N/A	N/A
23	Plant Unit Info	74.5	17,745	32.0%	N/A	32.0%	N/A						
24	Willow PV Solar												
25	Solar		1,834					N/A	N/A	N/A	N/A	N/A	N/A
26	Plant Unit Info	74.5	1,834	3.3%	9.7%	34.2%	N/A						
27	System Totals												
28	Plant Unit Info	28,240	11,022,999				7,277			80,213,901	234,122,553	2.12	
29													
30													
31													
32													
33													
34													
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ESTIMATED FOR THE PERIOD OF: JANUARY 2021 THROUGH DECEMBER 2021

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.	PLANT UNIT	Net Capability (MW)	Net Generation (MWH)	Capacity Factor	Equivalent Availability Factor	Net Output Factor	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost ($)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel ($/Unit)
1	**Jun - 2021**												
2	Babcock PV Solar												
3	Solar		13,902					N/A	N/A	N/A	N/A	N/A	N/A
4	Plant Unit Info	74.5	13,902	25.9%	N/A	25.9%	N/A						
5	Babcock Preserve PV Solar												
6	Solar		14,140					N/A	N/A	N/A	N/A	N/A	N/A
7	Plant Unit Info	74.5	14,140	26.4%	N/A	26.4%	N/A						
8	Barefoot PV Solar												
9	Solar		14,269					N/A	N/A	N/A	N/A	N/A	N/A
10	Plant Unit Info	74.5	14,269	26.6%	N/A	26.6%	N/A						
11	Blue Cypress PV Solar												
12	Solar		14,777					N/A	N/A	N/A	N/A	N/A	N/A
13	Plant Unit Info	74.5	14,777	27.6%	N/A	27.6%	N/A						
14	Blue Heron PV Solar												
15	Solar		14,140					N/A	N/A	N/A	N/A	N/A	N/A
16	Plant Unit Info	74.5	14,140	26.4%	N/A	26.4%	N/A						
17	CCEC 3												
18	Light Oil		0					0	0	0	0	0.00	0.00
19	Gas		584,742				6,766	3,956,146	1,000,000	3,956,146	15,805,815	2.70	4.00
20	Plant Unit Info	1,308.0	584,742	62.1%	93.4%	62.1%	6,766			3,956,146	15,805,815	2.70	
21	Cattle Ranch PV Solar												
22	Solar		15,362					N/A	N/A	N/A	N/A	N/A	N/A
23	Plant Unit Info	74.5	15,362	28.6%	N/A	28.6%	N/A						
24	Citrus PV Solar												
25	Solar		14,087					N/A	N/A	N/A	N/A	N/A	N/A
26	Plant Unit Info	74.5	14,087	26.3%	N/A	26.3%	N/A						
27	Coral Farms PV Solar												
28	Solar		16,007					N/A	N/A	N/A	N/A	N/A	N/A
29	Plant Unit Info	74.5	16,007	29.8%	N/A	29.8%	N/A						
30	Desoto Solar												
31	Solar		4,355					N/A	N/A	N/A	N/A	N/A	N/A
32	Plant Unit Info	25.0	4,355	24.2%	N/A	24.2%	N/A						
33	Discovery PV Solar												
34	Solar		12,666					N/A	N/A	N/A	N/A	N/A	N/A
35	Plant Unit Info	74.5	12,666	23.6%	N/A	23.6%	N/A						
36	Egret PV Solar												
37	Solar		14,902					N/A	N/A	N/A	N/A	N/A	N/A
38	Plant Unit Info	74.5	14,902	27.8%	N/A	27.8%	N/A						
39	Fort Drum PV Solar												
40	Solar		0					N/A	N/A	N/A	N/A	N/A	N/A
41	Plant Unit Info	0.0	0	N/A	N/A	N/A	N/A						
42	Fort Myers 2												
43	Gas		699,227				7,254	5,072,149	1,000,000	5,072,149	20,260,351	2.90	3.99

ESTIMATED FOR THE PERIOD OF: JANUARY 2021 THROUGH DECEMBER 2021

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.	PLANT UNIT	Net Capability (MW)	Net Generation (MWH)	Capacity Factor	Equivalent Availability Factor	Net Output Factor	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost ($)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel ($/Unit)
1	Plant Unit Info	1,730.0	699,227	56.1%	93.8%	56.1%	7,254			5,072,149	20,260,351	2.90	
2	Fort Myers 3A												
3	Light Oil		0					0	0	0	0	0.00	0.00
4	Gas		0					0	0	0	0	0.00	0.00
5	Plant Unit Info	164.0	0	N/A	93.7%	N/A	N/A						
6	Fort Myers 3B												
7	Light Oil		0					0	0	0	0	0.00	0.00
8	Gas		0					0	0	0	0	0.00	0.00
9	Plant Unit Info	168.0	0	N/A	93.7%	N/A	N/A						
10	Fort Myers 3C												
11	Light Oil		0					0	0	0	0	0.00	0.00
12	Gas		10,620				10,590	112,461	1,000,000	112,461	449,871	4.24	4.00
13	Plant Unit Info	219.0	10,620	6.7%	93.7%	6.7%	10,590			112,461	449,871	4.24	
14	Fort Myers 3D												
15	Light Oil		0					0	0	0	0	0.00	0.00
16	Gas		9,923				10,536	104,550	1,000,000	104,550	418,216	4.21	4.00
17	Plant Unit Info	219.0	9,923	6.3%	93.7%	6.3%	10,536			104,550	418,216	4.21	
18	Echo River PV Solar												
19	Solar		19,127					N/A	N/A	N/A	N/A	N/A	N/A
20	Plant Unit Info	74.5	19,127	35.7%	N/A	35.7%	N/A						
21	Hammock PV Solar												
22	Solar		14,497					N/A	N/A	N/A	N/A	N/A	N/A
23	Plant Unit Info	74.5	14,497	27.0%	N/A	27.0%	N/A						
24	Hibiscus PV Solar												
25	Solar		14,985					N/A	N/A	N/A	N/A	N/A	N/A
26	Plant Unit Info	74.5	14,985	27.9%	N/A	27.9%	N/A						
27	Horizon PV Solar												
28	Solar		16,044					N/A	N/A	N/A	N/A	N/A	N/A
29	Plant Unit Info	74.5	16,044	29.9%	N/A	29.9%	N/A						
30	Indian River PV Solar												
31	Solar		14,768					N/A	N/A	N/A	N/A	N/A	N/A
32	Plant Unit Info	74.5	14,768	27.5%	N/A	27.5%	N/A						
33	Indiantown												
34	Plant Unit Info	0.0	0	N/A	N/A	N/A	N/A						
35	Interstate PV Solar												
36	Solar		14,383					N/A	N/A	N/A	N/A	N/A	N/A
37	Plant Unit Info	74.5	14,383	26.8%	N/A	26.8%	N/A						
38	Lakeside PV Solar												
39	Solar		13,962					N/A	N/A	N/A	N/A	N/A	N/A
40	Plant Unit Info	74.5	13,962	26.0%	N/A	26.0%	N/A						
41	Lauderdale 6A												
42	Light Oil		0					0	0	0	0	0.00	0.00
43	Gas		14,615				10,580	154,627	1,000,000	154,627	618,250	4.23	4.00

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(1) Line No.	(2) PLANT UNIT	(3) Net Capability (MW)	(4) Net Generation (MWH)	(5) Capacity Factor	(6) Equivalent Availability Factor	(7) Net Output Factor	(8) Avg Net Heat Rate (BTU/KWH)	(9) Fuel Burned (Units)	(10) Fuel Heat Value (BTU/Unit)	(11) Fuel Burned (MMBTU)	(12) As Burned Fuel Cost ($)	(13) Fuel Cost per KWH (cents/KWH)	(14) Cost of Fuel ($/Unit)
1	Plant Unit Info	216.0	14,615	9.4%	94.0%	9.4%	10,580			154,627	618,250	4.23	
2	Lauderdale 6B												
3	Light Oil		0					0	0	0	0	0.00	0.00
4	Gas		16,216				10,569	171,379	1,000,000	171,379	685,004	4.22	4.00
5	Plant Unit Info	216.0	16,216	10.4%	94.0%	10.4%	10,569			171,379	685,004	4.22	
6	Lauderdale 6C												
7	Light Oil		0					0	0	0	0	0.00	0.00
8	Gas		0					0	0	0	0	0.00	0.00
9	Plant Unit Info	216.0	0	N/A	94.0%	N/A	N/A						
10	Lauderdale 6D												
11	Light Oil		0					0	0	0	0	0.00	0.00
12	Gas		0					0	0	0	0	0.00	0.00
13	Plant Unit Info	216.0	0	N/A	94.0%	N/A	N/A						
14	Lauderdale 6E												
15	Light Oil		0					0	0	0	0	0.00	0.00
16	Gas		0					0	0	0	0	0.00	0.00
17	Plant Unit Info	216.0	0	N/A	94.0%	N/A	N/A						
18	Loggerhead PV Solar												
19	Solar		14,530					N/A	N/A	N/A	N/A	N/A	N/A
20	Plant Unit Info	74.5	14,530	27.1%	N/A	27.1%	N/A						
21	Magnolia PV Solar												
22	Solar		15,010					N/A	N/A	N/A	N/A	N/A	N/A
23	Plant Unit Info	74.5	15,010	28.0%	N/A	28.0%	N/A						
24	Manatee 1												
25	Heavy Oil		2,365				12,007	4,438	6,400,000	28,400	304,219	12.86	68.56
26	Gas		18,644				12,007	223,855	1,000,000	223,855	874,746	4.69	3.91
27	Plant Unit Info	789.0	21,009	3.7%	94.1%	3.7%	12,007			252,255	1,178,965	5.61	
28	Manatee 2												
29	Heavy Oil		3,524				11,565	6,368	6,399,996	40,753	436,544	12.39	68.56
30	Gas		97,370				11,565	1,126,109	1,000,000	1,126,109	4,402,353	4.52	3.91
31	Plant Unit Info	789.0	100,894	17.8%	94.1%	17.8%	11,565			1,166,862	4,838,897	4.80	
32	Manatee 3												
33	Gas		311,479				7,467	2,325,800	1,000,000	2,325,800	9,090,007	2.92	3.91
34	Plant Unit Info	1,223.0	311,479	35.4%	93.9%	35.4%	7,467			2,325,800	9,090,007	2.92	
35	Manatee PV Solar												
36	Solar		14,433					N/A	N/A	N/A	N/A	N/A	N/A
37	Plant Unit Info	74.5	14,433	26.9%	N/A	26.9%	N/A						
38	Martin 3												
39	Gas		168,342				7,555	1,271,838	1,000,000	1,271,838	4,984,241	2.96	3.92
40	Plant Unit Info	464.0	168,342	50.4%	93.9%	50.4%	7,555			1,271,838	4,984,241	2.96	
41	Martin 4												
42	Gas		0					0	0	0	0	0.00	0.00
43	Plant Unit Info	464.0	0	N/A	N/A	N/A	N/A						

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(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.	PLANT UNIT	Net Capability (MW)	Net Generation (MWH)	Capacity Factor	Equivalent Availability Factor	Net Output Factor	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost ($)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel ($/Unit)
1	Martin 8 Solar												
2	Solar		13,260					N/A	N/A	N/A	N/A	N/A	N/A
3	Plant Unit Info	75.0	13,260	24.6%	N/A	24.6%	N/A						
4	Martin 8												
5	Light Oil		0					0	0	0	0	0.00	0.00
6	Gas		272,154				7,638	2,078,633	1,000,000	2,078,633	8,183,513	3.01	3.94
7	Plant Unit Info	1,218.0	272,154	31.0%	93.5%	31.0%	7,638			2,078,633	8,183,513	3.01	
8	Miami-Dade PV Solar												
9	Solar		13,587					N/A	N/A	N/A	N/A	N/A	N/A
10	Plant Unit Info	74.5	13,587	25.3%	N/A	25.3%	N/A						
11	Nassau PV Solar												
12	Solar		14,832					N/A	N/A	N/A	N/A	N/A	N/A
13	Plant Unit Info	74.5	14,832	27.7%	N/A	27.7%	N/A						
14	Northern Preserve PV Solar												
15	Solar		12,290					N/A	N/A	N/A	N/A	N/A	N/A
16	Plant Unit Info	74.5	12,290	22.9%	N/A	22.9%	N/A						
17	Okeechobee 1												
18	Light Oil		0					0	0	0	0	0.00	0.00
19	Gas		1,053,893				6,269	6,606,971	1,000,000	6,606,971	26,092,706	2.48	3.95
20	Plant Unit Info	1,618.0	1,053,893	90.5%	93.0%	90.5%	6,269			6,606,971	26,092,706	2.48	
21	Okeechobee PV Solar												
22	Solar		15,386					N/A	N/A	N/A	N/A	N/A	N/A
23	Plant Unit Info	74.5	15,386	28.7%	N/A	28.7%	N/A						
24	Orange Blossom PV Solar												
25	Solar		6,967					N/A	N/A	N/A	N/A	N/A	N/A
26	Plant Unit Info	74.5	6,967	13.0%	50.0%	26.0%	N/A						
27	Palm Bay PV Solar												
28	Solar		13,962					N/A	N/A	N/A	N/A	N/A	N/A
29	Plant Unit Info	74.5	13,962	26.0%	N/A	26.0%	N/A						
30	PEEC												
31	Gas		809,066				6,352	5,138,966	1,000,000	5,138,966	20,520,652	2.54	3.99
32	Plant Unit Info	1,254.0	809,066	89.6%	93.0%	89.6%	6,352			5,138,966	20,520,652	2.54	
33	Pelican PV Solar												
34	Solar		13,941					N/A	N/A	N/A	N/A	N/A	N/A
35	Plant Unit Info	74.5	13,941	26.0%	N/A	26.0%	N/A						
36	Pioneer Trail PV Solar												
37	Solar		14,304					N/A	N/A	N/A	N/A	N/A	N/A
38	Plant Unit Info	74.5	14,304	26.7%	N/A	26.7%	N/A						
39	Riviera 5												
40	Light Oil		0					0	0	0	0	0.00	0.00
41	Gas		630,216				6,746	4,251,733	1,000,000	4,251,733	16,791,239	2.66	3.95
42	Plant Unit Info	1,308.0	630,216	66.9%	93.4%	66.9%	6,746			4,251,733	16,791,239	2.66	
43	Rodeo PV Solar												

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(1) Line No.	(2) PLANT UNIT	(3) Net Capability (MW)	(4) Net Generation (MWH)	(5) Capacity Factor	(6) Equivalent Availability Factor	(7) Net Output Factor	(8) Avg Net Heat Rate (BTU/KWH)	(9) Fuel Burned (Units)	(10) Fuel Heat Value (BTU/Unit)	(11) Fuel Burned (MMBTU)	(12) As Burned Fuel Cost ($)	(13) Fuel Cost per KWH (cents/KWH)	(14) Cost of Fuel ($/Unit)
1	Solar		15,600					N/A	N/A	N/A	N/A	N/A	N/A
2	Plant Unit Info	74.5	15,600	29.1%	N/A	29.1%	N/A						
3	Sabal Palm PV Solar												
4	Solar		13,956					N/A	N/A	N/A	N/A	N/A	N/A
5	Plant Unit Info	74.5	13,956	26.0%	N/A	26.0%	N/A						
6	Sanford 4												
7	Gas		403,802				7,227	2,918,400	1,000,000	2,918,400	11,657,922	2.89	3.99
8	Plant Unit Info	1,147.0	403,802	48.9%	94.1%	48.9%	7,227			2,918,400	11,657,922	2.89	
9	Sanford 5												
10	Gas		430,733				7,117	3,065,710	1,000,000	3,065,710	12,246,377	2.84	3.99
11	Plant Unit Info	1,147.0	430,733	52.2%	94.1%	52.2%	7,117			3,065,710	12,246,377	2.84	
12	Scherer 4												
13	Coal		179,595				11,426	120,705	17,000,000	2,051,993	5,174,604	2.88	42.87
14	Plant Unit Info	636.0	179,595	39.2%	92.2%	39.2%	11,426			2,051,993	5,174,604	2.88	
15	Southfork PV Solar												
16	Solar		18,398					N/A	N/A	N/A	N/A	N/A	N/A
17	Plant Unit Info	74.5	18,398	34.3%	N/A	34.3%	N/A						
18	Space Coast												
19	Solar		1,447					N/A	N/A	N/A	N/A	N/A	N/A
20	Plant Unit Info	10.0	1,447	20.1%	N/A	20.1%	N/A						
21	St Lucie 1												
22	Nuclear		688,631				10,560	7,271,879	1,000,000	7,271,879	3,409,056	0.50	0.47
23	Plant Unit Info	981.0	688,631	97.5%	97.5%	97.5%	10,560			7,271,879	3,409,056	0.50	
24	St Lucie 2												
25	Nuclear		589,637				10,496	6,188,655	1,000,000	6,188,655	2,685,876	0.46	0.43
26	Plant Unit Info	840.0	589,637	97.5%	97.5%	97.5%	10,496			6,188,655	2,685,876	0.46	
27	Sunshine Gateway PV Solar												
28	Solar		15,129					N/A	N/A	N/A	N/A	N/A	N/A
29	Plant Unit Info	74.5	15,129	28.2%	N/A	28.2%	N/A						
30	Sweet Bay PV Solar												
31	Solar		12,407					N/A	N/A	N/A	N/A	N/A	N/A
32	Plant Unit Info	74.5	12,407	23.1%	N/A	23.1%	N/A						
33	Trailside PV Solar												
34	Solar		15,136					N/A	N/A	N/A	N/A	N/A	N/A
35	Plant Unit Info	74.5	15,136	28.2%	N/A	28.2%	N/A						
36	Turkey Point 3												
37	Nuclear		587,592				10,818	6,356,806	1,000,000	6,356,806	3,060,001	0.52	0.48
38	Plant Unit Info	837.0	587,592	97.5%	97.5%	97.5%	10,818			6,356,806	3,060,001	0.52	
39	Turkey Point 4												
40	Nuclear		590,400				10,767	6,356,778	1,000,000	6,356,778	3,668,497	0.62	0.58
41	Plant Unit Info	841.0	590,400	97.5%	97.5%	97.5%	10,767			6,356,778	3,668,497	0.62	
42	Turkey Point 5												
43	Light Oil		0					0	0	0	0	0.00	0.00

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(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.	PLANT UNIT	Net Capability (MW)	Net Generation (MWH)	Capacity Factor	Equivalent Availability Factor	Net Output Factor	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost ($)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel ($/Unit)
1	Gas		446,140				7,183	3,204,671	1,000,000	3,204,671	12,801,653	2.87	3.99
2	Plant Unit Info	1,256.0	446,140	49.3%	93.9%	49.3%	7,183			3,204,671	12,801,653	2.87	
3	Twin Lakes PV Solar												
4	Solar		14,949					N/A	N/A	N/A	N/A	N/A	N/A
5	Plant Unit Info	74.5	14,949	27.9%	N/A	27.9%	N/A						
6	Union Springs PV Solar												
7	Solar		14,994					N/A	N/A	N/A	N/A	N/A	N/A
8	Plant Unit Info	74.5	14,994	28.0%	N/A	28.0%	N/A						
9	WCEC 01												
10	Light Oil		0					0	0	0	0	0.00	0.00
11	Gas		678,947				6,732	4,570,532	1,000,000	4,570,532	17,857,089	2.63	3.91
12	Plant Unit Info	1,223.0	678,947	77.1%	93.7%	77.1%	6,732			4,570,532	17,857,089	2.63	
13	WCEC 02												
14	Light Oil		0					0	0	0	0	0.00	0.00
15	Gas		735,582				6,673	4,908,381	1,000,000	4,908,381	19,176,657	2.61	3.91
16	Plant Unit Info	1,223.0	735,582	83.5%	93.7%	83.5%	6,673			4,908,381	19,176,657	2.61	
17	WCEC 03												
18	Light Oil		0					0	0	0	0	0.00	0.00
19	Gas		753,718				6,691	5,043,209	1,000,000	5,043,209	19,703,238	2.61	3.91
20	Plant Unit Info	1,228.0	753,718	85.3%	93.7%	85.3%	6,691			5,043,209	19,703,238	2.61	
21	Wildflower PV Solar												
22	Solar		14,677					N/A	N/A	N/A	N/A	N/A	N/A
23	Plant Unit Info	74.5	14,677	27.4%	N/A	27.4%	N/A						
24	Willow PV Solar												
25	Solar		15,168					N/A	N/A	N/A	N/A	N/A	N/A
26	Plant Unit Info	74.5	15,168	28.3%	N/A	28.3%	N/A						
27	System Totals												
28	Plant Unit Info	28,315	11,357,910				7,449			84,601,384	241,358,695	2.13	
29													
30													
31													
32													
33													
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ESTIMATED FOR THE PERIOD OF: JANUARY 2021 THROUGH DECEMBER 2021

(1) Line No.	(2) PLANT UNIT	(3) Net Capability (MW)	(4) Net Generation (MWH)	(5) Capacity Factor	(6) Equivalent Availability Factor	(7) Net Output Factor	(8) Avg Net Heat Rate (BTU/KWH)	(9) Fuel Burned (Units)	(10) Fuel Heat Value (BTU/Unit)	(11) Fuel Burned (MMBTU)	(12) As Burned Fuel Cost ($)	(13) Fuel Cost per KWH (cents/KWH)	(14) Cost of Fuel ($/Unit)
1	**Jul - 2021**												
2	Babcock PV Solar												
3	Solar		14,422					N/A	N/A	N/A	N/A	N/A	N/A
4	Plant Unit Info	74.5	14,422	26.0%	N/A	26.0%	N/A						
5	Babcock Preserve PV Solar												
6	Solar		15,420					N/A	N/A	N/A	N/A	N/A	N/A
7	Plant Unit Info	74.5	15,420	27.8%	N/A	27.8%	N/A						
8	Barefoot PV Solar												
9	Solar		15,838					N/A	N/A	N/A	N/A	N/A	N/A
10	Plant Unit Info	74.5	15,838	28.6%	N/A	28.6%	N/A						
11	Blue Cypress PV Solar												
12	Solar		16,150					N/A	N/A	N/A	N/A	N/A	N/A
13	Plant Unit Info	74.5	16,150	29.1%	N/A	29.1%	N/A						
14	Blue Heron PV Solar												
15	Solar		15,420					N/A	N/A	N/A	N/A	N/A	N/A
16	Plant Unit Info	74.5	15,420	27.8%	N/A	27.8%	N/A						
17	CCEC 3												
18	Light Oil		0					0	0	0	0	0.00	0.00
19	Gas		632,624				6,758	4,275,496	1,000,000	4,275,496	16,895,947	2.67	3.95
20	Plant Unit Info	1,308.0	632,624	65.0%	93.4%	65.0%	6,758			4,275,496	16,895,947	2.67	
21	Cattle Ranch PV Solar												
22	Solar		16,889					N/A	N/A	N/A	N/A	N/A	N/A
23	Plant Unit Info	74.5	16,889	30.5%	N/A	30.5%	N/A						
24	Citrus PV Solar												
25	Solar		14,809					N/A	N/A	N/A	N/A	N/A	N/A
26	Plant Unit Info	74.5	14,809	26.7%	N/A	26.7%	N/A						
27	Coral Farms PV Solar												
28	Solar		16,719					N/A	N/A	N/A	N/A	N/A	N/A
29	Plant Unit Info	74.5	16,719	30.2%	N/A	30.2%	N/A						
30	Desoto Solar												
31	Solar		4,546					N/A	N/A	N/A	N/A	N/A	N/A
32	Plant Unit Info	25.0	4,546	24.4%	N/A	24.4%	N/A						
33	Discovery PV Solar												
34	Solar		13,812					N/A	N/A	N/A	N/A	N/A	N/A
35	Plant Unit Info	74.5	13,812	24.9%	N/A	24.9%	N/A						
36	Egret PV Solar												
37	Solar		16,383					N/A	N/A	N/A	N/A	N/A	N/A
38	Plant Unit Info	74.5	16,383	29.6%	N/A	29.6%	N/A						
39	Fort Drum PV Solar												
40	Solar		13,517					N/A	N/A	N/A	N/A	N/A	N/A
41	Plant Unit Info	74.5	13,517	24.4%	N/A	24.4%	N/A						
42	Fort Myers 2												
43	Gas		724,764				7,208	5,224,202	1,000,000	5,224,202	20,642,847	2.85	3.95

ESTIMATED FOR THE PERIOD OF: JANUARY 2021 THROUGH DECEMBER 2021

(1) Line No.	(2) PLANT UNIT	(3) Net Capability (MW)	(4) Net Generation (MWH)	(5) Capacity Factor	(6) Equivalent Availability Factor	(7) Net Output Factor	(8) Avg Net Heat Rate (BTU/KWH)	(9) Fuel Burned (Units)	(10) Fuel Heat Value (BTU/Unit)	(11) Fuel Burned (MMBTU)	(12) As Burned Fuel Cost ($)	(13) Fuel Cost per KWH (cents/KWH)	(14) Cost of Fuel ($/Unit)
1	Plant Unit Info	1,730.0	724,764	56.3%	93.8%	56.3%	7,208			5,224,202	20,642,847	2.85	
2	Fort Myers 3A												
3	Light Oil		1,038				14,681	2,614	5,830,008	15,239	232,001	22.35	88.76
4	Gas		0					0	0	0	0	0.00	0.00
5	Plant Unit Info	164.0	1,038	0.9%	93.7%	0.9%	14,681			15,239	232,001	22.35	
6	Fort Myers 3B												
7	Light Oil		513				14,784	1,301	5,829,989	7,584	115,460	22.51	88.76
8	Gas		0					0	0	0	0	0.00	0.00
9	Plant Unit Info	168.0	513	0.4%	93.7%	0.4%	14,784			7,584	115,460	22.51	
10	Fort Myers 3C												
11	Light Oil		0					0	0	0	0	0.00	0.00
12	Gas		7,088				10,530	74,635	1,000,000	74,635	295,335	4.17	3.96
13	Plant Unit Info	219.0	7,088	4.4%	93.7%	4.4%	10,530			74,635	295,335	4.17	
14	Fort Myers 3D												
15	Light Oil		0					0	0	0	0	0.00	0.00
16	Gas		7,088				10,530	74,635	1,000,000	74,635	295,014	4.16	3.95
17	Plant Unit Info	219.0	7,088	4.4%	93.7%	4.4%	10,530			74,635	295,014	4.16	
18	Echo River PV Solar												
19	Solar		19,942					N/A	N/A	N/A	N/A	N/A	N/A
20	Plant Unit Info	74.5	19,942	36.0%	N/A	36.0%	N/A						
21	Hammock PV Solar												
22	Solar		15,832					N/A	N/A	N/A	N/A	N/A	N/A
23	Plant Unit Info	74.5	15,832	28.6%	N/A	28.6%	N/A						
24	Hibiscus PV Solar												
25	Solar		15,689					N/A	N/A	N/A	N/A	N/A	N/A
26	Plant Unit Info	74.5	15,689	28.3%	N/A	28.3%	N/A						
27	Horizon PV Solar												
28	Solar		16,746					N/A	N/A	N/A	N/A	N/A	N/A
29	Plant Unit Info	74.5	16,746	30.2%	N/A	30.2%	N/A						
30	Indian River PV Solar												
31	Solar		16,135					N/A	N/A	N/A	N/A	N/A	N/A
32	Plant Unit Info	74.5	16,135	29.1%	N/A	29.1%	N/A						
33	Indiantown												
34	Plant Unit Info	0.0	0	N/A	N/A	N/A	N/A						
35	Interstate PV Solar												
36	Solar		15,280					N/A	N/A	N/A	N/A	N/A	N/A
37	Plant Unit Info	74.5	15,280	27.6%	N/A	27.6%	N/A						
38	Lakeside PV Solar												
39	Solar		15,225					N/A	N/A	N/A	N/A	N/A	N/A
40	Plant Unit Info	74.5	15,225	27.5%	N/A	27.5%	N/A						
41	Lauderdale 6A												
42	Light Oil		0					0	0	0	0	0.00	0.00
43	Gas		11,411				10,536	120,222	1,000,000	120,222	474,818	4.16	3.95

ESTIMATED FOR THE PERIOD OF: JANUARY 2021 THROUGH DECEMBER 2021

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.	PLANT UNIT	Net Capability (MW)	Net Generation (MWH)	Capacity Factor	Equivalent Availability Factor	Net Output Factor	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost ($)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel ($/Unit)
1	Plant Unit Info	216.0	11,411	7.1%	94.0%	7.1%	10,536			120,222	474,818	4.16	
2	Lauderdale 6B												
3	Light Oil		0					0	0	0	0	0.00	0.00
4	Gas		11,011				10,518	115,809	1,000,000	115,809	457,403	4.15	3.95
5	Plant Unit Info	216.0	11,011	6.9%	94.0%	6.9%	10,518			115,809	457,403	4.15	
6	Lauderdale 6C												
7	Light Oil		0					0	0	0	0	0.00	0.00
8	Gas		0					0	0	0	0	0.00	0.00
9	Plant Unit Info	216.0	0	N/A	94.0%	N/A	N/A						
10	Lauderdale 6D												
11	Light Oil		469				16,503	1,328	5,829,981	7,740	93,271	19.89	70.25
12	Gas		0					0	0	0	0	0.00	0.00
13	Plant Unit Info	216.0	469	0.3%	94.0%	0.3%	16,503			7,740	93,271	19.89	
14	Lauderdale 6E												
15	Light Oil		0					0	0	0	0	0.00	0.00
16	Gas		0					0	0	0	0	0.00	0.00
17	Plant Unit Info	216.0	0	N/A	94.0%	N/A	N/A						
18	Loggerhead PV Solar												
19	Solar		16,009					N/A	N/A	N/A	N/A	N/A	N/A
20	Plant Unit Info	74.5	16,009	28.9%	N/A	28.9%	N/A						
21	Magnolia PV Solar												
22	Solar		16,502					N/A	N/A	N/A	N/A	N/A	N/A
23	Plant Unit Info	74.5	16,502	29.8%	N/A	29.8%	N/A						
24	Manatee 1												
25	Heavy Oil		3,486				11,638	6,340	6,399,996	40,577	434,658	12.47	68.56
26	Gas		53,400				11,638	621,488	1,000,000	621,488	2,401,273	4.50	3.86
27	Plant Unit Info	789.0	56,886	9.7%	94.1%	9.7%	11,638			662,065	2,835,932	4.99	
28	Manatee 2												
29	Heavy Oil		3,567				11,461	6,388	6,399,999	40,883	437,936	12.28	68.56
30	Gas		101,396				11,461	1,162,047	1,000,000	1,162,047	4,490,813	4.43	3.86
31	Plant Unit Info	789.0	104,963	17.9%	94.1%	17.9%	11,461			1,202,930	4,928,749	4.70	
32	Manatee 3												
33	Gas		397,905				7,449	2,963,902	1,000,000	2,963,902	11,447,630	2.88	3.86
34	Plant Unit Info	1,223.0	397,905	43.7%	93.9%	43.7%	7,449			2,963,902	11,447,630	2.88	
35	Manatee PV Solar												
36	Solar		14,533					N/A	N/A	N/A	N/A	N/A	N/A
37	Plant Unit Info	74.5	14,533	26.2%	N/A	26.2%	N/A						
38	Martin 3												
39	Gas		180,382				7,536	1,359,412	1,000,000	1,359,412	5,286,867	2.93	3.89
40	Plant Unit Info	464.0	180,382	52.3%	93.9%	52.3%	7,536			1,359,412	5,286,867	2.93	
41	Martin 4												
42	Gas		162,077				7,571	1,227,064	1,000,000	1,227,064	4,769,535	2.94	3.89
43	Plant Unit Info	464.0	162,077	47.0%	87.5%	50.2%	7,571			1,227,064	4,769,535	2.94	

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(1) Line No.	(2) PLANT UNIT	(3) Net Capability (MW)	(4) Net Generation (MWH)	(5) Capacity Factor	(6) Equivalent Availability Factor	(7) Net Output Factor	(8) Avg Net Heat Rate (BTU/KWH)	(9) Fuel Burned (Units)	(10) Fuel Heat Value (BTU/Unit)	(11) Fuel Burned (MMBTU)	(12) As Burned Fuel Cost ($)	(13) Fuel Cost per KWH (cents/KWH)	(14) Cost of Fuel ($/Unit)
1	Martin 8 Solar												
2	Solar		12,679					N/A	N/A	N/A	N/A	N/A	N/A
3	Plant Unit Info	75.0	12,679	22.7%	N/A	22.7%	N/A						
4	Martin 8												
5	Light Oil		0					0	0	0	0	0.00	0.00
6	Gas		242,196				7,664	1,856,116	1,000,000	1,856,116	7,236,938	2.99	3.90
7	Plant Unit Info	1,218.0	242,196	26.7%	93.5%	26.7%	7,664			1,856,116	7,236,938	2.99	
8	Miami-Dade PV Solar												
9	Solar		14,897					N/A	N/A	N/A	N/A	N/A	N/A
10	Plant Unit Info	74.5	14,897	26.9%	N/A	26.9%	N/A						
11	Nassau PV Solar												
12	Solar		16,306					N/A	N/A	N/A	N/A	N/A	N/A
13	Plant Unit Info	74.5	16,306	29.4%	N/A	29.4%	N/A						
14	Northern Preserve PV Solar												
15	Solar		13,402					N/A	N/A	N/A	N/A	N/A	N/A
16	Plant Unit Info	74.5	13,402	24.2%	N/A	24.2%	N/A						
17	Okeechobee 1												
18	Light Oil		0					0	0	0	0	0.00	0.00
19	Gas		1,092,362				6,267	6,846,105	1,000,000	6,846,105	26,740,960	2.45	3.91
20	Plant Unit Info	1,618.0	1,092,362	90.7%	93.0%	90.7%	6,267			6,846,105	26,740,960	2.45	
21	Okeechobee PV Solar												
22	Solar		16,177					N/A	N/A	N/A	N/A	N/A	N/A
23	Plant Unit Info	74.5	16,177	29.2%	N/A	29.2%	N/A						
24	Orange Blossom PV Solar												
25	Solar		15,196					N/A	N/A	N/A	N/A	N/A	N/A
26	Plant Unit Info	74.5	15,196	27.4%	N/A	27.4%	N/A						
27	Palm Bay PV Solar												
28	Solar		15,225					N/A	N/A	N/A	N/A	N/A	N/A
29	Plant Unit Info	74.5	15,225	27.5%	N/A	27.5%	N/A						
30	PEEC												
31	Gas		836,728				6,351	5,313,951	1,000,000	5,313,951	20,999,323	2.51	3.95
32	Plant Unit Info	1,254.0	836,728	89.7%	93.0%	89.7%	6,351			5,313,951	20,999,323	2.51	
33	Pelican PV Solar												
34	Solar		15,202					N/A	N/A	N/A	N/A	N/A	N/A
35	Plant Unit Info	74.5	15,202	27.4%	N/A	27.4%	N/A						
36	Pioneer Trail PV Solar												
37	Solar		15,188					N/A	N/A	N/A	N/A	N/A	N/A
38	Plant Unit Info	74.5	15,188	27.4%	N/A	27.4%	N/A						
39	Riviera 5												
40	Light Oil		0					0	0	0	0	0.00	0.00
41	Gas		710,714				6,708	4,767,218	1,000,000	4,767,218	18,620,803	2.62	3.91
42	Plant Unit Info	1,308.0	710,714	73.0%	93.4%	73.0%	6,708			4,767,218	18,620,803	2.62	
43	Rodeo PV Solar												

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(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.	PLANT UNIT	Net Capability (MW)	Net Generation (MWH)	Capacity Factor	Equivalent Availability Factor	Net Output Factor	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost ($)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel ($/Unit)
1	Solar		17,151					N/A	N/A	N/A	N/A	N/A	N/A
2	Plant Unit Info	74.5	17,151	30.9%	N/A	30.9%	N/A						
3	Sabal Palm PV Solar												
4	Solar		15,219					N/A	N/A	N/A	N/A	N/A	N/A
5	Plant Unit Info	74.5	15,219	27.5%	N/A	27.5%	N/A						
6	Sanford 4												
7	Gas		438,449				7,203	3,158,166	1,000,000	3,158,166	12,478,211	2.85	3.95
8	Plant Unit Info	1,147.0	438,449	51.4%	94.1%	51.4%	7,203			3,158,166	12,478,211	2.85	
9	Sanford 5												
10	Gas		471,697				7,086	3,342,229	1,000,000	3,342,229	13,205,979	2.80	3.95
11	Plant Unit Info	1,147.0	471,697	55.3%	94.1%	55.3%	7,086			3,342,229	13,205,979	2.80	
12	Scherer 4												
13	Coal		186,128				11,419	125,019	17,000,000	2,125,320	5,374,318	2.89	42.99
14	Plant Unit Info	636.0	186,128	39.3%	92.2%	39.3%	11,419			2,125,320	5,374,318	2.89	
15	Southfork PV Solar												
16	Solar		18,794					N/A	N/A	N/A	N/A	N/A	N/A
17	Plant Unit Info	74.5	18,794	33.9%	N/A	33.9%	N/A						
18	Space Coast												
19	Solar		1,555					N/A	N/A	N/A	N/A	N/A	N/A
20	Plant Unit Info	10.0	1,555	20.9%	N/A	20.9%	N/A						
21	St Lucie 1												
22	Nuclear		711,586				10,560	7,514,275	1,000,000	7,514,275	3,522,692	0.50	0.47
23	Plant Unit Info	981.0	711,586	97.5%	97.5%	97.5%	10,560			7,514,275	3,522,692	0.50	
24	St Lucie 2												
25	Nuclear		609,292				10,496	6,394,944	1,000,000	6,394,944	2,775,405	0.46	0.43
26	Plant Unit Info	840.0	609,292	97.5%	97.5%	97.5%	10,496			6,394,944	2,775,405	0.46	
27	Sunshine Gateway PV Solar												
28	Solar		16,190					N/A	N/A	N/A	N/A	N/A	N/A
29	Plant Unit Info	74.5	16,190	29.2%	N/A	29.2%	N/A						
30	Sweet Bay PV Solar												
31	Solar		13,905					N/A	N/A	N/A	N/A	N/A	N/A
32	Plant Unit Info	74.5	13,905	25.1%	N/A	25.1%	N/A						
33	Trailside PV Solar												
34	Solar		16,640					N/A	N/A	N/A	N/A	N/A	N/A
35	Plant Unit Info	74.5	16,640	30.0%	N/A	30.0%	N/A						
36	Turkey Point 3												
37	Nuclear		607,178				10,818	6,568,699	1,000,000	6,568,699	3,162,001	0.52	0.48
38	Plant Unit Info	837.0	607,178	97.5%	97.5%	97.5%	10,818			6,568,699	3,162,001	0.52	
39	Turkey Point 4												
40	Nuclear		610,080				10,767	6,568,671	1,000,000	6,568,671	3,790,780	0.62	0.58
41	Plant Unit Info	841.0	610,080	97.5%	97.5%	97.5%	10,767			6,568,671	3,790,780	0.62	
42	Turkey Point 5												
43	Light Oil		0					0	0	0	0	0.00	0.00

ESTIMATED FOR THE PERIOD OF: JANUARY 2021 THROUGH DECEMBER 2021

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.	PLANT UNIT	Net Capability (MW)	Net Generation (MWH)	Capacity Factor	Equivalent Availability Factor	Net Output Factor	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost ($)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel ($/Unit)
1	Gas		488,393				7,147	3,490,384	1,000,000	3,490,384	13,791,565	2.82	3.95
2	Plant Unit Info	1,256.0	488,393	52.3%	93.9%	52.3%	7,147			3,490,384	13,791,565	2.82	
3	Twin Lakes PV Solar												
4	Solar		16,435					N/A	N/A	N/A	N/A	N/A	N/A
5	Plant Unit Info	74.5	16,435	29.7%	N/A	29.7%	N/A						
6	Union Springs PV Solar												
7	Solar		16,485					N/A	N/A	N/A	N/A	N/A	N/A
8	Plant Unit Info	74.5	16,485	29.7%	N/A	29.7%	N/A						
9	WCEC 01												
10	Light Oil		0					0	0	0	0	0.00	0.00
11	Gas		751,554				6,691	5,028,575	1,000,000	5,028,575	19,414,533	2.58	3.86
12	Plant Unit Info	1,223.0	751,554	82.6%	93.7%	82.6%	6,691			5,028,575	19,414,533	2.58	
13	WCEC 02												
14	Light Oil		0					0	0	0	0	0.00	0.00
15	Gas		783,675				6,657	5,217,189	1,000,000	5,217,189	20,142,657	2.57	3.86
16	Plant Unit Info	1,223.0	783,675	86.1%	93.7%	86.1%	6,657			5,217,189	20,142,657	2.57	
17	WCEC 03												
18	Light Oil		0					0	0	0	0	0.00	0.00
19	Gas		782,961				6,697	5,243,670	1,000,000	5,243,670	20,244,892	2.59	3.86
20	Plant Unit Info	1,228.0	782,961	85.7%	93.7%	85.7%	6,697			5,243,670	20,244,892	2.59	
21	Wildflower PV Solar												
22	Solar		15,980					N/A	N/A	N/A	N/A	N/A	N/A
23	Plant Unit Info	74.5	15,980	28.8%	N/A	28.8%	N/A						
24	Willow PV Solar												
25	Solar		16,675					N/A	N/A	N/A	N/A	N/A	N/A
26	Plant Unit Info	74.5	16,675	30.1%	N/A	30.1%	N/A						
27	System Totals												
28	Plant Unit Info	28,389	12,256,331				7,406			90,766,447	260,271,868	2.12	
29													
30													
31													
32													
33													
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ESTIMATED FOR THE PERIOD OF: JANUARY 2021 THROUGH DECEMBER 2021

(1) Line No.	(2) PLANT UNIT	(3) Net Capability (MW)	(4) Net Generation (MWH)	(5) Capacity Factor	(6) Equivalent Availability Factor	(7) Net Output Factor	(8) Avg Net Heat Rate (BTU/KWH)	(9) Fuel Burned (Units)	(10) Fuel Heat Value (BTU/Unit)	(11) Fuel Burned (MMBTU)	(12) As Burned Fuel Cost ($)	(13) Fuel Cost per KWH (cents/KWH)	(14) Cost of Fuel ($/Unit)
1	**Aug - 2021**												
2	Babcock PV Solar												
3	Solar		14,342					N/A	N/A	N/A	N/A	N/A	N/A
4	Plant Unit Info	74.5	14,342	25.9%	N/A	25.9%	N/A						
5	Babcock Preserve PV Solar												
6	Solar		14,937					N/A	N/A	N/A	N/A	N/A	N/A
7	Plant Unit Info	74.5	14,937	27.0%	N/A	27.0%	N/A						
8	Barefoot PV Solar												
9	Solar		15,018					N/A	N/A	N/A	N/A	N/A	N/A
10	Plant Unit Info	74.5	15,018	27.1%	N/A	27.1%	N/A						
11	Blue Cypress PV Solar												
12	Solar		15,243					N/A	N/A	N/A	N/A	N/A	N/A
13	Plant Unit Info	74.5	15,243	27.5%	N/A	27.5%	N/A						
14	Blue Heron PV Solar												
15	Solar		14,937					N/A	N/A	N/A	N/A	N/A	N/A
16	Plant Unit Info	74.5	14,937	27.0%	N/A	27.0%	N/A						
17	CCEC 3												
18	Light Oil		0					0	0	0	0	0.00	0.00
19	Gas		645,630				6,753	4,360,145	1,000,000	4,360,145	17,115,323	2.65	3.93
20	Plant Unit Info	1,308.0	645,630	66.4%	93.4%	66.4%	6,753			4,360,145	17,115,323	2.65	
21	Cattle Ranch PV Solar												
22	Solar		15,651					N/A	N/A	N/A	N/A	N/A	N/A
23	Plant Unit Info	74.5	15,651	28.2%	N/A	28.2%	N/A						
24	Citrus PV Solar												
25	Solar		14,611					N/A	N/A	N/A	N/A	N/A	N/A
26	Plant Unit Info	74.5	14,611	26.4%	N/A	26.4%	N/A						
27	Coral Farms PV Solar												
28	Solar		16,129					N/A	N/A	N/A	N/A	N/A	N/A
29	Plant Unit Info	74.5	16,129	29.1%	N/A	29.1%	N/A						
30	Desoto Solar												
31	Solar		4,326					N/A	N/A	N/A	N/A	N/A	N/A
32	Plant Unit Info	25.0	4,326	23.3%	N/A	23.3%	N/A						
33	Discovery PV Solar												
34	Solar		13,380					N/A	N/A	N/A	N/A	N/A	N/A
35	Plant Unit Info	74.5	13,380	24.1%	N/A	24.1%	N/A						
36	Egret PV Solar												
37	Solar		15,182					N/A	N/A	N/A	N/A	N/A	N/A
38	Plant Unit Info	74.5	15,182	27.4%	N/A	27.4%	N/A						
39	Fort Drum PV Solar												
40	Solar		13,094					N/A	N/A	N/A	N/A	N/A	N/A
41	Plant Unit Info	74.5	13,094	23.6%	N/A	23.6%	N/A						
42	Fort Myers 2												
43	Gas		766,396				7,221	5,534,431	1,000,000	5,534,431	21,728,327	2.84	3.93

ESTIMATED FOR THE PERIOD OF: JANUARY 2021 THROUGH DECEMBER 2021

(1) Line No.	(2) PLANT UNIT	(3) Net Capability (MW)	(4) Net Generation (MWH)	(5) Capacity Factor	(6) Equivalent Availability Factor	(7) Net Output Factor	(8) Avg Net Heat Rate (BTU/KWH)	(9) Fuel Burned (Units)	(10) Fuel Heat Value (BTU/Unit)	(11) Fuel Burned (MMBTU)	(12) As Burned Fuel Cost ($)	(13) Fuel Cost per KWH (cents/KWH)	(14) Cost of Fuel ($/Unit)
1	Plant Unit Info	1,730.0	766,396	59.5%	93.8%	59.5%	7,221			5,534,431	21,728,327	2.84	
2	Fort Myers 3A												
3	Light Oil		450				16,000	1,235	5,830,007	7,200	109,614	24.36	88.76
4	Gas		0					0	0	0	0	0.00	0.00
5	Plant Unit Info	164.0	450	0.4%	93.7%	0.4%	16,000			7,200	109,614	24.36	
6	Fort Myers 3B												
7	Light Oil		1,090				14,280	2,670	5,830,003	15,565	236,964	21.74	88.76
8	Gas		0					0	0	0	0	0.00	0.00
9	Plant Unit Info	168.0	1,090	0.9%	93.7%	0.9%	14,280			15,565	236,964	21.74	
10	Fort Myers 3C												
11	Light Oil		0					0	0	0	0	0.00	0.00
12	Gas		14,175				10,509	148,971	1,000,000	148,971	584,557	4.12	3.92
13	Plant Unit Info	219.0	14,175	8.7%	93.7%	8.7%	10,509			148,971	584,557	4.12	
14	Fort Myers 3D												
15	Light Oil		0					0	0	0	0	0.00	0.00
16	Gas		13,365				10,526	140,681	1,000,000	140,681	552,376	4.13	3.93
17	Plant Unit Info	219.0	13,365	8.2%	93.7%	8.2%	10,526			140,681	552,376	4.13	
18	Echo River PV Solar												
19	Solar		18,710					N/A	N/A	N/A	N/A	N/A	N/A
20	Plant Unit Info	74.5	18,710	33.8%	N/A	33.8%	N/A						
21	Hammock PV Solar												
22	Solar		15,279					N/A	N/A	N/A	N/A	N/A	N/A
23	Plant Unit Info	74.5	15,279	27.6%	N/A	27.6%	N/A						
24	Hibiscus PV Solar												
25	Solar		15,424					N/A	N/A	N/A	N/A	N/A	N/A
26	Plant Unit Info	74.5	15,424	27.8%	N/A	27.8%	N/A						
27	Horizon PV Solar												
28	Solar		16,140					N/A	N/A	N/A	N/A	N/A	N/A
29	Plant Unit Info	74.5	16,140	29.1%	N/A	29.1%	N/A						
30	Indian River PV Solar												
31	Solar		15,230					N/A	N/A	N/A	N/A	N/A	N/A
32	Plant Unit Info	74.5	15,230	27.5%	N/A	27.5%	N/A						
33	Indiantown												
34	Plant Unit Info	0.0	0	N/A	N/A	N/A	N/A						
35	Interstate PV Solar												
36	Solar		15,104					N/A	N/A	N/A	N/A	N/A	N/A
37	Plant Unit Info	74.5	15,104	27.3%	N/A	27.3%	N/A						
38	Lakeside PV Solar												
39	Solar		14,748					N/A	N/A	N/A	N/A	N/A	N/A
40	Plant Unit Info	74.5	14,748	26.6%	N/A	26.6%	N/A						
41	Lauderdale 6A												
42	Light Oil		0					0	0	0	0	0.00	0.00
43	Gas		17,417				10,514	183,118	1,000,000	183,118	718,669	4.13	3.92

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(1) Line No.	(2) PLANT UNIT	(3) Net Capability (MW)	(4) Net Generation (MWH)	(5) Capacity Factor	(6) Equivalent Availability Factor	(7) Net Output Factor	(8) Avg Net Heat Rate (BTU/KWH)	(9) Fuel Burned (Units)	(10) Fuel Heat Value (BTU/Unit)	(11) Fuel Burned (MMBTU)	(12) As Burned Fuel Cost ($)	(13) Fuel Cost per KWH (cents/KWH)	(14) Cost of Fuel ($/Unit)
1	Plant Unit Info	216.0	17,417	10.8%	94.0%	10.8%	10,514			183,118	718,669	4.13	
2	Lauderdale 6B												
3	Light Oil		0					0	0	0	0	0.00	0.00
4	Gas		16,416				10,528	172,835	1,000,000	172,835	678,447	4.13	3.93
5	Plant Unit Info	216.0	16,416	10.2%	94.0%	10.2%	10,528			172,835	678,447	4.13	
6	Lauderdale 6C												
7	Light Oil		670				13,451	1,546	5,829,991	9,012	108,599	16.21	70.25
8	Gas		0					0	0	0	0	0.00	0.00
9	Plant Unit Info	216.0	670	0.4%	94.0%	0.4%	13,451			9,012	108,599	16.21	
10	Lauderdale 6D												
11	Light Oil		670				13,451	1,546	5,829,991	9,012	108,599	16.21	70.25
12	Gas		0					0	0	0	0	0.00	0.00
13	Plant Unit Info	216.0	670	0.4%	94.0%	0.4%	13,451			9,012	108,599	16.21	
14	Lauderdale 6E												
15	Light Oil		0					0	0	0	0	0.00	0.00
16	Gas		0					0	0	0	0	0.00	0.00
17	Plant Unit Info	216.0	0	N/A	94.0%	N/A	N/A						
18	Loggerhead PV Solar												
19	Solar		15,258					N/A	N/A	N/A	N/A	N/A	N/A
20	Plant Unit Info	74.5	15,258	27.5%	N/A	27.5%	N/A						
21	Magnolia PV Solar												
22	Solar		15,292					N/A	N/A	N/A	N/A	N/A	N/A
23	Plant Unit Info	74.5	15,292	27.6%	N/A	27.6%	N/A						
24	Manatee 1												
25	Heavy Oil		8,297				11,234	14,564	6,399,999	93,211	998,471	12.03	68.56
26	Gas		105,599				11,234	1,186,265	1,000,000	1,186,265	4,549,813	4.31	3.84
27	Plant Unit Info	789.0	113,896	19.4%	94.1%	19.4%	11,234			1,279,476	5,548,284	4.87	
28	Manatee 2												
29	Heavy Oil		5,700				11,396	10,149	6,400,002	64,951	695,751	12.21	68.56
30	Gas		100,898				11,396	1,149,803	1,000,000	1,149,803	4,416,358	4.38	3.84
31	Plant Unit Info	789.0	106,598	18.2%	94.1%	18.2%	11,396			1,214,754	5,112,109	4.80	
32	Manatee 3												
33	Gas		343,156				7,388	2,535,253	1,000,000	2,535,253	9,728,851	2.84	3.84
34	Plant Unit Info	1,223.0	343,156	37.7%	93.9%	37.7%	7,388			2,535,253	9,728,851	2.84	
35	Manatee PV Solar												
36	Solar		14,390					N/A	N/A	N/A	N/A	N/A	N/A
37	Plant Unit Info	74.5	14,390	26.0%	N/A	26.0%	N/A						
38	Martin 3												
39	Gas		188,374				7,538	1,419,920	1,000,000	1,419,920	5,489,088	2.91	3.87
40	Plant Unit Info	464.0	188,374	54.6%	93.9%	54.6%	7,538			1,419,920	5,489,088	2.91	
41	Martin 4												
42	Gas		175,885				7,545	1,326,984	1,000,000	1,326,984	5,128,204	2.92	3.86
43	Plant Unit Info	464.0	175,885	51.0%	93.9%	51.0%	7,545			1,326,984	5,128,204	2.92	

ESTIMATED FOR THE PERIOD OF: JANUARY 2021 THROUGH DECEMBER 2021

(1) Line No.	(2) PLANT UNIT	(3) Net Capability (MW)	(4) Net Generation (MWH)	(5) Capacity Factor	(6) Equivalent Availability Factor	(7) Net Output Factor	(8) Avg Net Heat Rate (BTU/KWH)	(9) Fuel Burned (Units)	(10) Fuel Heat Value (BTU/Unit)	(11) Fuel Burned (MMBTU)	(12) As Burned Fuel Cost ($)	(13) Fuel Cost per KWH (cents/KWH)	(14) Cost of Fuel ($/Unit)
1	Martin 8 Solar												
2	Solar		11,873					N/A	N/A	N/A	N/A	N/A	N/A
3	Plant Unit Info	75.0	11,873	21.3%	N/A	21.3%	N/A						
4	Martin 8												
5	Light Oil		0					0	0	0	0	0.00	0.00
6	Gas		282,406				7,570	2,137,860	1,000,000	2,137,860	8,284,950	2.93	3.88
7	Plant Unit Info	1,218.0	282,406	31.2%	93.5%	31.2%	7,570			2,137,860	8,284,950	2.93	
8	Miami-Dade PV Solar												
9	Solar		14,745					N/A	N/A	N/A	N/A	N/A	N/A
10	Plant Unit Info	74.5	14,745	26.6%	N/A	26.6%	N/A						
11	Nassau PV Solar												
12	Solar		15,111					N/A	N/A	N/A	N/A	N/A	N/A
13	Plant Unit Info	74.5	15,111	27.3%	N/A	27.3%	N/A						
14	Northern Preserve PV Solar												
15	Solar		12,982					N/A	N/A	N/A	N/A	N/A	N/A
16	Plant Unit Info	74.5	12,982	23.4%	N/A	23.4%	N/A						
17	Okeechobee 1												
18	Light Oil		0					0	0	0	0	0.00	0.00
19	Gas		1,093,033				6,267	6,849,917	1,000,000	6,849,917	26,562,107	2.43	3.88
20	Plant Unit Info	1,618.0	1,093,033	90.8%	93.0%	90.8%	6,267			6,849,917	26,562,107	2.43	
21	Okeechobee PV Solar												
22	Solar		15,842					N/A	N/A	N/A	N/A	N/A	N/A
23	Plant Unit Info	74.5	15,842	28.6%	N/A	28.6%	N/A						
24	Orange Blossom PV Solar												
25	Solar		14,720					N/A	N/A	N/A	N/A	N/A	N/A
26	Plant Unit Info	74.5	14,720	26.6%	N/A	26.6%	N/A						
27	Palm Bay PV Solar												
28	Solar		14,748					N/A	N/A	N/A	N/A	N/A	N/A
29	Plant Unit Info	74.5	14,748	26.6%	N/A	26.6%	N/A						
30	PEEC												
31	Gas		842,243				6,346	5,345,040	1,000,000	5,345,040	20,986,768	2.49	3.93
32	Plant Unit Info	1,254.0	842,243	90.3%	93.0%	90.3%	6,346			5,345,040	20,986,768	2.49	
33	Pelican PV Solar												
34	Solar		14,727					N/A	N/A	N/A	N/A	N/A	N/A
35	Plant Unit Info	74.5	14,727	26.6%	N/A	26.6%	N/A						
36	Pioneer Trail PV Solar												
37	Solar		15,069					N/A	N/A	N/A	N/A	N/A	N/A
38	Plant Unit Info	74.5	15,069	27.2%	N/A	27.2%	N/A						
39	Riviera 5												
40	Light Oil		0					0	0	0	0	0.00	0.00
41	Gas		790,315				6,650	5,255,318	1,000,000	5,255,318	20,378,686	2.58	3.88
42	Plant Unit Info	1,308.0	790,315	81.2%	93.4%	81.2%	6,650			5,255,318	20,378,686	2.58	
43	Rodeo PV Solar												

ESTIMATED FOR THE PERIOD OF: JANUARY 2021 THROUGH DECEMBER 2021

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.	PLANT UNIT	Net Capability (MW)	Net Generation (MWH)	Capacity Factor	Equivalent Availability Factor	Net Output Factor	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost ($)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel ($/Unit)
1	Solar		15,894					N/A	N/A	N/A	N/A	N/A	N/A
2	Plant Unit Info	74.5	15,894	28.7%	N/A	28.7%	N/A						
3	Sabal Palm PV Solar												
4	Solar		14,743					N/A	N/A	N/A	N/A	N/A	N/A
5	Plant Unit Info	74.5	14,743	26.6%	N/A	26.6%	N/A						
6	Sanford 4												
7	Gas		453,682				7,188	3,261,137	1,000,000	3,261,137	12,802,314	2.82	3.93
8	Plant Unit Info	1,147.0	453,682	53.2%	94.1%	53.2%	7,188			3,261,137	12,802,314	2.82	
9	Sanford 5												
10	Gas		478,638				7,074	3,386,049	1,000,000	3,386,049	13,293,140	2.78	3.93
11	Plant Unit Info	1,147.0	478,638	56.1%	94.1%	56.1%	7,074			3,386,049	13,293,140	2.78	
12	Scherer 4												
13	Coal		193,251				11,361	129,150	17,000,000	2,195,543	5,570,548	2.88	43.13
14	Plant Unit Info	636.0	193,251	40.8%	92.2%	40.8%	11,361			2,195,543	5,570,548	2.88	
15	Southfork PV Solar												
16	Solar		18,357					N/A	N/A	N/A	N/A	N/A	N/A
17	Plant Unit Info	74.5	18,357	33.1%	N/A	33.1%	N/A						
18	Space Coast												
19	Solar		1,545					N/A	N/A	N/A	N/A	N/A	N/A
20	Plant Unit Info	10.0	1,545	20.8%	N/A	20.8%	N/A						
21	St Lucie 1												
22	Nuclear		711,586				10,560	7,514,275	1,000,000	7,514,275	3,522,692	0.50	0.47
23	Plant Unit Info	981.0	711,586	97.5%	97.5%	97.5%	10,560			7,514,275	3,522,692	0.50	
24	St Lucie 2												
25	Nuclear		530,674				10,496	5,569,790	1,000,000	5,569,790	2,417,289	0.46	0.43
26	Plant Unit Info	840.0	530,674	84.9%	84.9%	97.5%	10,496			5,569,790	2,417,289	0.46	
27	Sunshine Gateway PV Solar												
28	Solar		15,292					N/A	N/A	N/A	N/A	N/A	N/A
29	Plant Unit Info	74.5	15,292	27.6%	N/A	27.6%	N/A						
30	Sweet Bay PV Solar												
31	Solar		13,274					N/A	N/A	N/A	N/A	N/A	N/A
32	Plant Unit Info	74.5	13,274	24.0%	N/A	24.0%	N/A						
33	Trailside PV Solar												
34	Solar		15,420					N/A	N/A	N/A	N/A	N/A	N/A
35	Plant Unit Info	74.5	15,420	27.8%	N/A	27.8%	N/A						
36	Turkey Point 3												
37	Nuclear		607,178				10,818	6,568,699	1,000,000	6,568,699	3,162,001	0.52	0.48
38	Plant Unit Info	837.0	607,178	97.5%	97.5%	97.5%	10,818			6,568,699	3,162,001	0.52	
39	Turkey Point 4												
40	Nuclear		610,080				10,767	6,568,671	1,000,000	6,568,671	3,790,780	0.62	0.58
41	Plant Unit Info	841.0	610,080	97.5%	97.5%	97.5%	10,767			6,568,671	3,790,780	0.62	
42	Turkey Point 5												
43	Light Oil		0					0	0	0	0	0.00	0.00

ESTIMATED FOR THE PERIOD OF: JANUARY 2021 THROUGH DECEMBER 2021

(1) Line No.	(2) PLANT UNIT	(3) Net Capability (MW)	(4) Net Generation (MWH)	(5) Capacity Factor	(6) Equivalent Availability Factor	(7) Net Output Factor	(8) Avg Net Heat Rate (BTU/KWH)	(9) Fuel Burned (Units)	(10) Fuel Heat Value (BTU/Unit)	(11) Fuel Burned (MMBTU)	(12) As Burned Fuel Cost ($)	(13) Fuel Cost per KWH (cents/KWH)	(14) Cost of Fuel ($/Unit)
1	Gas		490,310				7,128	3,495,038	1,000,000	3,495,038	13,720,532	2.80	3.93
2	Plant Unit Info	1,256.0	490,310	52.5%	93.9%	52.5%	7,128			3,495,038	13,720,532	2.80	
3	Twin Lakes PV Solar												
4	Solar		15,230					N/A	N/A	N/A	N/A	N/A	N/A
5	Plant Unit Info	74.5	15,230	27.5%	N/A	27.5%	N/A						
6	Union Springs PV Solar												
7	Solar		15,276					N/A	N/A	N/A	N/A	N/A	N/A
8	Plant Unit Info	74.5	15,276	27.6%	N/A	27.6%	N/A						
9	WCEC 01												
10	Light Oil		0					0	0	0	0	0.00	0.00
11	Gas		775,959				6,671	5,176,080	1,000,000	5,176,080	19,839,379	2.56	3.83
12	Plant Unit Info	1,223.0	775,959	85.3%	93.7%	85.3%	6,671			5,176,080	19,839,379	2.56	
13	WCEC 02												
14	Light Oil		0					0	0	0	0	0.00	0.00
15	Gas		786,187				6,652	5,229,787	1,000,000	5,229,787	20,045,263	2.55	3.83
16	Plant Unit Info	1,223.0	786,187	86.4%	93.7%	86.4%	6,652			5,229,787	20,045,263	2.55	
17	WCEC 03												
18	Light Oil		0					0	0	0	0	0.00	0.00
19	Gas		787,915				6,688	5,269,640	1,000,000	5,269,640	20,198,033	2.56	3.83
20	Plant Unit Info	1,228.0	787,915	86.2%	93.7%	86.2%	6,688			5,269,640	20,198,033	2.56	
21	Wildflower PV Solar												
22	Solar		15,359					N/A	N/A	N/A	N/A	N/A	N/A
23	Plant Unit Info	74.5	15,359	27.7%	N/A	27.7%	N/A						
24	Willow PV Solar												
25	Solar		15,453					N/A	N/A	N/A	N/A	N/A	N/A
26	Plant Unit Info	74.5	15,453	27.9%	N/A	27.9%	N/A						
27	System Totals												
28	Plant Unit Info	28,389	12,445,730				7,407			92,180,201	267,522,496	2.15	
29													
30													
31													
32													
33													
34													
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ESTIMATED FOR THE PERIOD OF: JANUARY 2021 THROUGH DECEMBER 2021

(1) Line No.	(2) PLANT UNIT	(3) Net Capability (MW)	(4) Net Generation (MWH)	(5) Capacity Factor	(6) Equivalent Availability Factor	(7) Net Output Factor	(8) Avg Net Heat Rate (BTU/KWH)	(9) Fuel Burned (Units)	(10) Fuel Heat Value (BTU/Unit)	(11) Fuel Burned (MMBTU)	(12) As Burned Fuel Cost ($)	(13) Fuel Cost per KWH (cents/KWH)	(14) Cost of Fuel ($/Unit)
1	**Sep - 2021**												
2	Babcock PV Solar												
3	Solar		12,899					N/A	N/A	N/A	N/A	N/A	N/A
4	Plant Unit Info	74.5	12,899	24.1%	N/A	24.1%	N/A						
5	Babcock Preserve PV Solar												
6	Solar		14,167					N/A	N/A	N/A	N/A	N/A	N/A
7	Plant Unit Info	74.5	14,167	26.4%	N/A	26.4%	N/A						
8	Barefoot PV Solar												
9	Solar		13,957					N/A	N/A	N/A	N/A	N/A	N/A
10	Plant Unit Info	74.5	13,957	26.0%	N/A	26.0%	N/A						
11	Blue Cypress PV Solar												
12	Solar		14,290					N/A	N/A	N/A	N/A	N/A	N/A
13	Plant Unit Info	74.5	14,290	26.6%	N/A	26.6%	N/A						
14	Blue Heron PV Solar												
15	Solar		14,167					N/A	N/A	N/A	N/A	N/A	N/A
16	Plant Unit Info	74.5	14,167	26.4%	N/A	26.4%	N/A						
17	CCEC 3												
18	Light Oil		0					0	0	0	0	0.00	0.00
19	Gas		610,332				6,753	4,121,762	1,000,000	4,121,762	16,177,650	2.65	3.92
20	Plant Unit Info	1,308.0	610,332	64.8%	93.4%	64.8%	6,753			4,121,762	16,177,650	2.65	
21	Cattle Ranch PV Solar												
22	Solar		14,415					N/A	N/A	N/A	N/A	N/A	N/A
23	Plant Unit Info	74.5	14,415	26.9%	N/A	26.9%	N/A						
24	Citrus PV Solar												
25	Solar		13,630					N/A	N/A	N/A	N/A	N/A	N/A
26	Plant Unit Info	74.5	13,630	25.4%	N/A	25.4%	N/A						
27	Coral Farms PV Solar												
28	Solar		14,602					N/A	N/A	N/A	N/A	N/A	N/A
29	Plant Unit Info	74.5	14,602	27.2%	N/A	27.2%	N/A						
30	Desoto Solar												
31	Solar		3,868					N/A	N/A	N/A	N/A	N/A	N/A
32	Plant Unit Info	25.0	3,868	21.5%	N/A	21.5%	N/A						
33	Discovery PV Solar												
34	Solar		12,690					N/A	N/A	N/A	N/A	N/A	N/A
35	Plant Unit Info	74.5	12,690	23.7%	N/A	23.7%	N/A						
36	Egret PV Solar												
37	Solar		13,983					N/A	N/A	N/A	N/A	N/A	N/A
38	Plant Unit Info	74.5	13,983	26.1%	N/A	26.1%	N/A						
39	Fort Drum PV Solar												
40	Solar		12,419					N/A	N/A	N/A	N/A	N/A	N/A
41	Plant Unit Info	74.5	12,419	23.2%	N/A	23.2%	N/A						
42	Fort Myers 2												
43	Gas		703,206				7,224	5,079,969	1,000,000	5,079,969	19,939,165	2.84	3.93

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(1) Line No.	(2) PLANT UNIT	(3) Net Capability (MW)	(4) Net Generation (MWH)	(5) Capacity Factor	(6) Equivalent Availability Factor	(7) Net Output Factor	(8) Avg Net Heat Rate (BTU/KWH)	(9) Fuel Burned (Units)	(10) Fuel Heat Value (BTU/Unit)	(11) Fuel Burned (MMBTU)	(12) As Burned Fuel Cost ($)	(13) Fuel Cost per KWH (cents/KWH)	(14) Cost of Fuel ($/Unit)
1	Plant Unit Info	1,730.0	703,206	56.5%	93.8%	56.5%	7,224			5,079,969	19,939,165	2.84	
2	Fort Myers 3A												
3	Light Oil		0					0	0	0	0	0.00	0.00
4	Gas		0					0	0	0	0	0.00	0.00
5	Plant Unit Info	164.0	0	N/A	93.7%	N/A	N/A						
6	Fort Myers 3B												
7	Light Oil		562				14,028	1,352	5,829,981	7,884	120,027	21.36	88.76
8	Gas		0					0	0	0	0	0.00	0.00
9	Plant Unit Info	168.0	562	0.5%	93.7%	0.5%	14,028			7,884	120,027	21.36	
10	Fort Myers 3C												
11	Light Oil		0					0	0	0	0	0.00	0.00
12	Gas		10,733				10,513	112,839	1,000,000	112,839	443,111	4.13	3.93
13	Plant Unit Info	219.0	10,733	6.8%	93.7%	6.8%	10,513			112,839	443,111	4.13	
14	Fort Myers 3D												
15	Light Oil		0					0	0	0	0	0.00	0.00
16	Gas		11,543				10,520	121,429	1,000,000	121,429	477,253	4.13	3.93
17	Plant Unit Info	219.0	11,543	7.3%	93.7%	7.3%	10,520			121,429	477,253	4.13	
18	Echo River PV Solar												
19	Solar		16,335					N/A	N/A	N/A	N/A	N/A	N/A
20	Plant Unit Info	74.5	16,335	30.5%	N/A	30.5%	N/A						
21	Hammock PV Solar												
22	Solar		14,411					N/A	N/A	N/A	N/A	N/A	N/A
23	Plant Unit Info	74.5	14,411	26.9%	N/A	26.9%	N/A						
24	Hibiscus PV Solar												
25	Solar		13,975					N/A	N/A	N/A	N/A	N/A	N/A
26	Plant Unit Info	74.5	13,975	26.1%	N/A	26.1%	N/A						
27	Horizon PV Solar												
28	Solar		14,806					N/A	N/A	N/A	N/A	N/A	N/A
29	Plant Unit Info	74.5	14,806	27.6%	N/A	27.6%	N/A						
30	Indian River PV Solar												
31	Solar		14,277					N/A	N/A	N/A	N/A	N/A	N/A
32	Plant Unit Info	74.5	14,277	26.6%	N/A	26.6%	N/A						
33	Indiantown												
34	Plant Unit Info	0.0	0	N/A	N/A	N/A	N/A						
35	Interstate PV Solar												
36	Solar		14,079					N/A	N/A	N/A	N/A	N/A	N/A
37	Plant Unit Info	74.5	14,079	26.3%	N/A	26.3%	N/A						
38	Lakeside PV Solar												
39	Solar		13,989					N/A	N/A	N/A	N/A	N/A	N/A
40	Plant Unit Info	74.5	13,989	26.1%	N/A	26.1%	N/A						
41	Lauderdale 6A												
42	Light Oil		0					0	0	0	0	0.00	0.00
43	Gas		12,613				10,534	132,861	1,000,000	132,861	522,196	4.14	3.93

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(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.	PLANT UNIT	Net Capability (MW)	Net Generation (MWH)	Capacity Factor	Equivalent Availability Factor	Net Output Factor	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost ($)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel ($/Unit)
1	Plant Unit Info	216.0	12,613	8.1%	94.0%	8.1%	10,534			132,861	522,196	4.14	
2	Lauderdale 6B												
3	Light Oil		0					0	0	0	0	0.00	0.00
4	Gas		13,013				10,526	136,974	1,000,000	136,974	538,246	4.14	3.93
5	Plant Unit Info	216.0	13,013	8.4%	94.0%	8.4%	10,526			136,974	538,246	4.14	
6	Lauderdale 6C												
7	Light Oil		470				14,581	1,175	5,830,008	6,853	82,582	17.57	70.25
8	Gas		0					0	0	0	0	0.00	0.00
9	Plant Unit Info	216.0	470	0.3%	94.0%	0.3%	14,581			6,853	82,582	17.57	
10	Lauderdale 6D												
11	Light Oil		0					0	0	0	0	0.00	0.00
12	Gas		0					0	0	0	0	0.00	0.00
13	Plant Unit Info	216.0	0	N/A	94.0%	N/A	N/A						
14	Lauderdale 6E												
15	Light Oil		0					0	0	0	0	0.00	0.00
16	Gas		0					0	0	0	0	0.00	0.00
17	Plant Unit Info	216.0	0	N/A	94.0%	N/A	N/A						
18	Loggerhead PV Solar												
19	Solar		14,449					N/A	N/A	N/A	N/A	N/A	N/A
20	Plant Unit Info	74.5	14,449	26.9%	N/A	26.9%	N/A						
21	Magnolia PV Solar												
22	Solar		14,084					N/A	N/A	N/A	N/A	N/A	N/A
23	Plant Unit Info	74.5	14,084	26.3%	N/A	26.3%	N/A						
24	Manatee 1												
25	Heavy Oil		5,736				11,378	10,197	6,400,001	65,261	699,072	12.19	68.56
26	Gas		49,819				11,378	566,852	1,000,000	566,852	2,176,135	4.37	3.84
27	Plant Unit Info	789.0	55,555	9.8%	94.1%	9.8%	11,378			632,113	2,875,207	5.18	
28	Manatee 2												
29	Heavy Oil		2,977				11,482	5,341	6,399,994	34,180	366,134	12.30	68.56
30	Gas		97,971				11,482	1,124,876	1,000,000	1,124,876	4,319,855	4.41	3.84
31	Plant Unit Info	789.0	100,948	17.8%	94.1%	17.8%	11,482			1,159,056	4,685,989	4.64	
32	Manatee 3												
33	Gas		380,624				7,473	2,844,224	1,000,000	2,844,224	10,913,848	2.87	3.84
34	Plant Unit Info	1,223.0	380,624	43.2%	93.9%	43.2%	7,473			2,844,224	10,913,848	2.87	
35	Manatee PV Solar												
36	Solar		13,678					N/A	N/A	N/A	N/A	N/A	N/A
37	Plant Unit Info	74.5	13,678	25.5%	N/A	25.5%	N/A						
38	Martin 3												
39	Gas		178,981				7,563	1,353,579	1,000,000	1,353,579	5,235,817	2.93	3.87
40	Plant Unit Info	464.0	178,981	53.6%	93.9%	53.6%	7,563			1,353,579	5,235,817	2.93	
41	Martin 4												
42	Gas		172,655				7,576	1,308,081	1,000,000	1,308,081	5,054,950	2.93	3.86
43	Plant Unit Info	464.0	172,655	51.7%	93.9%	51.7%	7,576			1,308,081	5,054,950	2.93	

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(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.	PLANT UNIT	Net Capability (MW)	Net Generation (MWH)	Capacity Factor	Equivalent Availability Factor	Net Output Factor	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost ($)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel ($/Unit)
1	Martin 8 Solar												
2	Solar		10,320					N/A	N/A	N/A	N/A	N/A	N/A
3	Plant Unit Info	75.0	10,320	19.1%	N/A	19.1%	N/A						
4	Martin 8												
5	Light Oil		0					0	0	0	0	0.00	0.00
6	Gas		265,880				7,663	2,037,383	1,000,000	2,037,383	7,894,967	2.97	3.88
7	Plant Unit Info	1,218.0	265,880	30.3%	93.5%	30.3%	7,663			2,037,383	7,894,967	2.97	
8	Miami-Dade PV Solar												
9	Solar		13,518					N/A	N/A	N/A	N/A	N/A	N/A
10	Plant Unit Info	74.5	13,518	25.2%	N/A	25.2%	N/A						
11	Nassau PV Solar												
12	Solar		13,918					N/A	N/A	N/A	N/A	N/A	N/A
13	Plant Unit Info	74.5	13,918	26.0%	N/A	26.0%	N/A						
14	Northern Preserve PV Solar												
15	Solar		12,314					N/A	N/A	N/A	N/A	N/A	N/A
16	Plant Unit Info	74.5	12,314	23.0%	N/A	23.0%	N/A						
17	Okeechobee 1												
18	Light Oil		0					0	0	0	0	0.00	0.00
19	Gas		1,058,685				6,266	6,634,062	1,000,000	6,634,062	25,736,537	2.43	3.88
20	Plant Unit Info	1,618.0	1,058,685	90.9%	93.0%	90.9%	6,266			6,634,062	25,736,537	2.43	
21	Okeechobee PV Solar												
22	Solar		14,608					N/A	N/A	N/A	N/A	N/A	N/A
23	Plant Unit Info	74.5	14,608	27.2%	N/A	27.2%	N/A						
24	Orange Blossom PV Solar												
25	Solar		13,962					N/A	N/A	N/A	N/A	N/A	N/A
26	Plant Unit Info	74.5	13,962	26.0%	N/A	26.0%	N/A						
27	Palm Bay PV Solar												
28	Solar		13,989					N/A	N/A	N/A	N/A	N/A	N/A
29	Plant Unit Info	74.5	13,989	26.1%	N/A	26.1%	N/A						
30	PEEC												
31	Gas		818,120				6,343	5,189,434	1,000,000	5,189,434	20,370,358	2.49	3.93
32	Plant Unit Info	1,254.0	818,120	90.6%	93.0%	90.6%	6,343			5,189,434	20,370,358	2.49	
33	Pelican PV Solar												
34	Solar		13,968					N/A	N/A	N/A	N/A	N/A	N/A
35	Plant Unit Info	74.5	13,968	26.0%	N/A	26.0%	N/A						
36	Pioneer Trail PV Solar												
37	Solar		13,694					N/A	N/A	N/A	N/A	N/A	N/A
38	Plant Unit Info	74.5	13,694	25.5%	N/A	25.5%	N/A						
39	Riviera 5												
40	Light Oil		0					0	0	0	0	0.00	0.00
41	Gas		765,523				6,647	5,088,502	1,000,000	5,088,502	19,740,609	2.58	3.88
42	Plant Unit Info	1,308.0	765,523	81.3%	93.4%	81.3%	6,647			5,088,502	19,740,609	2.58	
43	Rodeo PV Solar												

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(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.	PLANT UNIT	Net Capability (MW)	Net Generation (MWH)	Capacity Factor	Equivalent Availability Factor	Net Output Factor	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost ($)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel ($/Unit)
1	Solar		14,639					N/A	N/A	N/A	N/A	N/A	N/A
2	Plant Unit Info	74.5	14,639	27.3%	N/A	27.3%	N/A						
3	Sabal Palm PV Solar												
4	Solar		13,983					N/A	N/A	N/A	N/A	N/A	N/A
5	Plant Unit Info	74.5	13,983	26.1%	N/A	26.1%	N/A						
6	Sanford 4												
7	Gas		429,137				7,202	3,090,644	1,000,000	3,090,644	12,131,049	2.83	3.93
8	Plant Unit Info	1,147.0	429,137	52.0%	94.1%	52.0%	7,202			3,090,644	12,131,049	2.83	
9	Sanford 5												
10	Gas		454,089				7,084	3,216,912	1,000,000	3,216,912	12,626,369	2.78	3.92
11	Plant Unit Info	1,147.0	454,089	55.0%	94.1%	55.0%	7,084			3,216,912	12,626,369	2.78	
12	Scherer 4												
13	Coal		184,198				11,385	123,358	17,000,000	2,097,080	5,329,017	2.89	43.20
14	Plant Unit Info	636.0	184,198	40.2%	92.2%	40.2%	11,385			2,097,080	5,329,017	2.89	
15	Southfork PV Solar												
16	Solar		16,374					N/A	N/A	N/A	N/A	N/A	N/A
17	Plant Unit Info	74.5	16,374	30.5%	N/A	30.5%	N/A						
18	Space Coast												
19	Solar		1,421					N/A	N/A	N/A	N/A	N/A	N/A
20	Plant Unit Info	10.0	1,421	19.7%	N/A	19.7%	N/A						
21	St Lucie 1												
22	Nuclear		688,631				10,560	7,271,879	1,000,000	7,271,879	3,409,056	0.50	0.47
23	Plant Unit Info	981.0	688,631	97.5%	97.5%	97.5%	10,560			7,271,879	3,409,056	0.50	
24	St Lucie 2												
25	Nuclear		-										
26	Plant Unit Info	840.0	0	N/A	N/A	N/A	N/A						
27	Sunshine Gateway PV Solar												
28	Solar		14,199					N/A	N/A	N/A	N/A	N/A	N/A
29	Plant Unit Info	74.5	14,199	26.5%	N/A	26.5%	N/A						
30	Sweet Bay PV Solar												
31	Solar		12,663					N/A	N/A	N/A	N/A	N/A	N/A
32	Plant Unit Info	74.5	12,663	23.6%	N/A	23.6%	N/A						
33	Trailside PV Solar												
34	Solar		14,203					N/A	N/A	N/A	N/A	N/A	N/A
35	Plant Unit Info	74.5	14,203	26.5%	N/A	26.5%	N/A						
36	Turkey Point 3												
37	Nuclear		587,592				10,818	6,356,806	1,000,000	6,356,806	3,060,001	0.52	0.48
38	Plant Unit Info	837.0	587,592	97.5%	97.5%	97.5%	10,818			6,356,806	3,060,001	0.52	
39	Turkey Point 4												
40	Nuclear		590,400				10,767	6,356,778	1,000,000	6,356,778	3,668,497	0.62	0.58
41	Plant Unit Info	841.0	590,400	97.5%	97.5%	97.5%	10,767			6,356,778	3,668,497	0.62	
42	Turkey Point 5												
43	Light Oil		0					0	0	0	0	0.00	0.00

ESTIMATED FOR THE PERIOD OF: JANUARY 2021 THROUGH DECEMBER 2021

(1) Line No.	(2) PLANT UNIT	(3) Net Capability (MW)	(4) Net Generation (MWH)	(5) Capacity Factor	(6) Equivalent Availability Factor	(7) Net Output Factor	(8) Avg Net Heat Rate (BTU/KWH)	(9) Fuel Burned (Units)	(10) Fuel Heat Value (BTU/Unit)	(11) Fuel Burned (MMBTU)	(12) As Burned Fuel Cost ($)	(13) Fuel Cost per KWH (cents/KWH)	(14) Cost of Fuel ($/Unit)
1	Gas		471,427				7,151	3,370,944	1,000,000	3,370,944	13,231,288	2.81	3.93
2	Plant Unit Info	1,256.0	471,427	52.1%	93.9%	52.1%	7,151			3,370,944	13,231,288	2.81	
3	Twin Lakes PV Solar												
4	Solar		14,028					N/A	N/A	N/A	N/A	N/A	N/A
5	Plant Unit Info	74.5	14,028	26.2%	N/A	26.2%	N/A						
6	Union Springs PV Solar												
7	Solar		14,070					N/A	N/A	N/A	N/A	N/A	N/A
8	Plant Unit Info	74.5	14,070	26.2%	N/A	26.2%	N/A						
9	WCEC 01												
10	Light Oil		0					0	0	0	0	0.00	0.00
11	Gas		758,070				6,671	5,057,140	1,000,000	5,057,140	19,398,681	2.56	3.84
12	Plant Unit Info	1,223.0	758,070	86.1%	93.7%	86.1%	6,671			5,057,140	19,398,681	2.56	
13	WCEC 02												
14	Light Oil		0					0	0	0	0	0.00	0.00
15	Gas		767,304				6,647	5,099,983	1,000,000	5,099,983	19,563,030	2.55	3.84
16	Plant Unit Info	1,223.0	767,304	87.1%	93.7%	87.1%	6,647			5,099,983	19,563,030	2.55	
17	WCEC 03												
18	Light Oil		0					0	0	0	0	0.00	0.00
19	Gas		764,287				6,683	5,107,578	1,000,000	5,107,578	19,592,169	2.56	3.84
20	Plant Unit Info	1,228.0	764,287	86.4%	93.7%	86.4%	6,683			5,107,578	19,592,169	2.56	
21	Wildflower PV Solar												
22	Solar		14,791					N/A	N/A	N/A	N/A	N/A	N/A
23	Plant Unit Info	74.5	14,791	27.6%	N/A	27.6%	N/A						
24	Willow PV Solar												
25	Solar		14,233					N/A	N/A	N/A	N/A	N/A	N/A
26	Plant Unit Info	74.5	14,233	26.5%	N/A	26.5%	N/A						
27	System Totals												
28	Plant Unit Info	28,389	11,418,643				7,268			82,992,749	252,817,668	2.21	
29													
30													
31													
32													
33													
34													
35													
36													
37													
38													
39													
40													
41													
42													
43													

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.	PLANT UNIT	Net Capability (MW)	Net Generation (MWH)	Capacity Factor	Equivalent Availability Factor	Net Output Factor	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost ($)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel ($/Unit)
1	**Oct - 2021**												
2	Babcock PV Solar												
3	Solar		13,941					N/A	N/A	N/A	N/A	N/A	N/A
4	Plant Unit Info	74.5	13,941	25.2%	N/A	25.2%	N/A						
5	Babcock Preserve PV Solar												
6	Solar		14,948					N/A	N/A	N/A	N/A	N/A	N/A
7	Plant Unit Info	74.5	14,948	27.0%	N/A	27.0%	N/A						
8	Barefoot PV Solar												
9	Solar		14,309					N/A	N/A	N/A	N/A	N/A	N/A
10	Plant Unit Info	74.5	14,309	25.8%	N/A	25.8%	N/A						
11	Blue Cypress PV Solar												
12	Solar		14,540					N/A	N/A	N/A	N/A	N/A	N/A
13	Plant Unit Info	74.5	14,540	26.2%	N/A	26.2%	N/A						
14	Blue Heron PV Solar												
15	Solar		14,948					N/A	N/A	N/A	N/A	N/A	N/A
16	Plant Unit Info	74.5	14,948	27.0%	N/A	27.0%	N/A						
17	CCEC 3												
18	Light Oil		0					0	0	0	0	0.00	0.00
19	Gas		622,938				6,761	4,211,591	1,000,000	4,211,591	17,512,916	2.81	4.16
20	Plant Unit Info	1,308.0	622,938	64.0%	93.4%	64.0%	6,761			4,211,591	17,512,916	2.81	
21	Cattle Ranch PV Solar												
22	Solar		14,269					N/A	N/A	N/A	N/A	N/A	N/A
23	Plant Unit Info	74.5	14,269	25.7%	N/A	25.7%	N/A						
24	Citrus PV Solar												
25	Solar		14,046					N/A	N/A	N/A	N/A	N/A	N/A
26	Plant Unit Info	74.5	14,046	25.3%	N/A	25.3%	N/A						
27	Coral Farms PV Solar												
28	Solar		15,020					N/A	N/A	N/A	N/A	N/A	N/A
29	Plant Unit Info	74.5	15,020	27.1%	N/A	27.1%	N/A						
30	Desoto Solar												
31	Solar		3,833					N/A	N/A	N/A	N/A	N/A	N/A
32	Plant Unit Info	25.0	3,833	20.6%	N/A	20.6%	N/A						
33	Discovery PV Solar												
34	Solar		13,390					N/A	N/A	N/A	N/A	N/A	N/A
35	Plant Unit Info	74.5	13,390	24.2%	N/A	24.2%	N/A						
36	Egret PV Solar												
37	Solar		13,841					N/A	N/A	N/A	N/A	N/A	N/A
38	Plant Unit Info	74.5	13,841	25.0%	N/A	25.0%	N/A						
39	Fort Drum PV Solar												
40	Solar		13,104					N/A	N/A	N/A	N/A	N/A	N/A
41	Plant Unit Info	74.5	13,104	23.6%	N/A	23.6%	N/A						
42	Fort Myers 2												
43	Gas		715,829				7,280	5,211,304	1,000,000	5,211,304	21,671,566	3.03	4.16

ESTIMATED FOR THE PERIOD OF: JANUARY 2021 THROUGH DECEMBER 2021

(1) Line No.	(2) PLANT UNIT	(3) Net Capability (MW)	(4) Net Generation (MWH)	(5) Capacity Factor	(6) Equivalent Availability Factor	(7) Net Output Factor	(8) Avg Net Heat Rate (BTU/KWH)	(9) Fuel Burned (Units)	(10) Fuel Heat Value (BTU/Unit)	(11) Fuel Burned (MMBTU)	(12) As Burned Fuel Cost ($)	(13) Fuel Cost per KWH (cents/KWH)	(14) Cost of Fuel ($/Unit)
1	Plant Unit Info	1,730.0	715,829	55.6%	85.2%	60.9%	7,280			5,211,304	21,671,566	3.03	
2	Fort Myers 3A												
3	Light Oil		0					0	0	0	0	0.00	0.00
4	Gas		0					0	0	0	0	0.00	0.00
5	Plant Unit Info	164.0	0	N/A	93.7%	N/A	N/A						
6	Fort Myers 3B												
7	Light Oil		0					0	0	0	0	0.00	0.00
8	Gas		0					0	0	0	0	0.00	0.00
9	Plant Unit Info	168.0	0	N/A	93.7%	N/A	N/A						
10	Fort Myers 3C												
11	Light Oil		0					0	0	0	0	0.00	0.00
12	Gas		3,038				10,529	31,987	1,000,000	31,987	133,543	4.40	4.17
13	Plant Unit Info	219.0	3,038	1.9%	93.7%	1.9%	10,529			31,987	133,543	4.40	
14	Fort Myers 3D												
15	Light Oil		0					0	0	0	0	0.00	0.00
16	Gas		3,038				10,529	31,987	1,000,000	31,987	133,427	4.39	4.17
17	Plant Unit Info	219.0	3,038	1.9%	93.7%	1.9%	10,529			31,987	133,427	4.39	
18	Echo River PV Solar												
19	Solar		16,339					N/A	N/A	N/A	N/A	N/A	N/A
20	Plant Unit Info	74.5	16,339	29.5%	N/A	29.5%	N/A						
21	Hammock PV Solar												
22	Solar		15,340					N/A	N/A	N/A	N/A	N/A	N/A
23	Plant Unit Info	74.5	15,340	27.7%	N/A	27.7%	N/A						
24	Hibiscus PV Solar												
25	Solar		13,972					N/A	N/A	N/A	N/A	N/A	N/A
26	Plant Unit Info	74.5	13,972	25.2%	N/A	25.2%	N/A						
27	Horizon PV Solar												
28	Solar		15,171					N/A	N/A	N/A	N/A	N/A	N/A
29	Plant Unit Info	74.5	15,171	27.4%	N/A	27.4%	N/A						
30	Indian River PV Solar												
31	Solar		14,532					N/A	N/A	N/A	N/A	N/A	N/A
32	Plant Unit Info	74.5	14,532	26.2%	N/A	26.2%	N/A						
33	Indiantown												
34	Plant Unit Info	0.0	0	N/A	N/A	N/A	N/A						
35	Interstate PV Solar												
36	Solar		14,238					N/A	N/A	N/A	N/A	N/A	N/A
37	Plant Unit Info	74.5	14,238	25.7%	N/A	25.7%	N/A						
38	Lakeside PV Solar												
39	Solar		14,759					N/A	N/A	N/A	N/A	N/A	N/A
40	Plant Unit Info	74.5	14,759	26.6%	N/A	26.6%	N/A						
41	Lauderdale 6A												
42	Light Oil		0					0	0	0	0	0.00	0.00
43	Gas		10,410				10,561	109,940	1,000,000	109,940	457,405	4.39	4.16

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(1) Line No.	(2) PLANT UNIT	(3) Net Capability (MW)	(4) Net Generation (MWH)	(5) Capacity Factor	(6) Equivalent Availability Factor	(7) Net Output Factor	(8) Avg Net Heat Rate (BTU/KWH)	(9) Fuel Burned (Units)	(10) Fuel Heat Value (BTU/Unit)	(11) Fuel Burned (MMBTU)	(12) As Burned Fuel Cost ($)	(13) Fuel Cost per KWH (cents/KWH)	(14) Cost of Fuel ($/Unit)
1	Plant Unit Info	216.0	10,410	6.5%	94.0%	6.5%	10,561			109,940	457,405	4.39	
2	Lauderdale 6B												
3	Light Oil		0					0	0	0	0	0.00	0.00
4	Gas		7,207				10,522	75,835	1,000,000	75,835	315,919	4.38	4.17
5	Plant Unit Info	216.0	7,207	4.5%	94.0%	4.5%	10,522			75,835	315,919	4.38	
6	Lauderdale 6C												
7	Light Oil		0					0	0	0	0	0.00	0.00
8	Gas		8,008				10,535	84,361	1,000,000	84,361	351,284	4.39	4.16
9	Plant Unit Info	216.0	8,008	5.0%	94.0%	5.0%	10,535			84,361	351,284	4.39	
10	Lauderdale 6D												
11	Light Oil		0					0	0	0	0	0.00	0.00
12	Gas		11,211				10,540	118,166	1,000,000	118,166	492,414	4.39	4.17
13	Plant Unit Info	216.0	11,211	7.0%	94.0%	7.0%	10,540			118,166	492,414	4.39	
14	Lauderdale 6E												
15	Light Oil		0					0	0	0	0	0.00	0.00
16	Gas		8,609				10,551	90,831	1,000,000	90,831	378,038	4.39	4.16
17	Plant Unit Info	216.0	8,609	5.4%	94.0%	5.4%	10,551			90,831	378,038	4.39	
18	Loggerhead PV Solar												
19	Solar		14,876					N/A	N/A	N/A	N/A	N/A	N/A
20	Plant Unit Info	74.5	14,876	26.8%	N/A	26.8%	N/A						
21	Magnolia PV Solar												
22	Solar		13,942					N/A	N/A	N/A	N/A	N/A	N/A
23	Plant Unit Info	74.5	13,942	25.2%	N/A	25.2%	N/A						
24	Manatee 1												
25	Heavy Oil		1,834				11,771	3,374	6,400,007	21,591	231,282	12.61	68.56
26	Gas		23,972				11,771	282,173	1,000,000	282,173	1,145,816	4.78	4.06
27	Plant Unit Info	789.0	25,806	4.4%	94.1%	4.4%	11,771			303,764	1,377,097	5.34	
28	Manatee 2												
29	Heavy Oil		1,130				11,480	2,028	6,399,988	12,977	139,009	12.30	68.56
30	Gas		28,121				11,480	322,828	1,000,000	322,828	1,312,360	4.67	4.07
31	Plant Unit Info	789.0	29,251	5.0%	94.1%	5.0%	11,480			335,805	1,451,369	4.96	
32	Manatee 3												
33	Gas		315,714				7,163	2,261,318	1,000,000	2,261,318	9,193,897	2.91	4.07
34	Plant Unit Info	1,223.0	315,714	34.7%	71.3%	44.8%	7,163			2,261,318	9,193,897	2.91	
35	Manatee PV Solar												
36	Solar		14,472					N/A	N/A	N/A	N/A	N/A	N/A
37	Plant Unit Info	74.5	14,472	26.1%	N/A	26.1%	N/A						
38	Martin 3												
39	Gas		87,282				8,061	703,617	1,000,000	703,617	2,867,492	3.29	4.08
40	Plant Unit Info	464.0	87,282	25.3%	93.9%	25.3%	8,061			703,617	2,867,492	3.29	
41	Martin 4												
42	Gas		168,658				7,556	1,274,444	1,000,000	1,274,444	5,190,465	3.08	4.07
43	Plant Unit Info	464.0	168,658	48.9%	93.9%	48.9%	7,556			1,274,444	5,190,465	3.08	

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(1) Line No.	(2) PLANT UNIT	(3) Net Capability (MW)	(4) Net Generation (MWH)	(5) Capacity Factor	(6) Equivalent Availability Factor	(7) Net Output Factor	(8) Avg Net Heat Rate (BTU/KWH)	(9) Fuel Burned (Units)	(10) Fuel Heat Value (BTU/Unit)	(11) Fuel Burned (MMBTU)	(12) As Burned Fuel Cost ($)	(13) Fuel Cost per KWH (cents/KWH)	(14) Cost of Fuel ($/Unit)
1	Martin 8 Solar												
2	Solar		9,114					N/A	N/A	N/A	N/A	N/A	N/A
3	Plant Unit Info	75.0	9,114	16.3%	N/A	16.3%	N/A						
4	Martin 8												
5	Light Oil		0					0	0	0	0	0.00	0.00
6	Gas		331,515				7,578	2,512,114	1,000,000	2,512,114	10,256,147	3.09	4.08
7	Plant Unit Info	1,218.0	331,515	36.6%	93.5%	36.6%	7,578			2,512,114	10,256,147	3.09	
8	Miami-Dade PV Solar												
9	Solar		13,970					N/A	N/A	N/A	N/A	N/A	N/A
10	Plant Unit Info	74.5	13,970	25.2%	N/A	25.2%	N/A						
11	Nassau PV Solar												
12	Solar		13,777					N/A	N/A	N/A	N/A	N/A	N/A
13	Plant Unit Info	74.5	13,777	24.9%	N/A	24.9%	N/A						
14	Northern Preserve PV Solar												
15	Solar		12,992					N/A	N/A	N/A	N/A	N/A	N/A
16	Plant Unit Info	74.5	12,992	23.4%	N/A	23.4%	N/A						
17	Okeechobee 1												
18	Light Oil		0					0	0	0	0	0.00	0.00
19	Gas		891,263				6,294	5,609,775	1,000,000	5,609,775	23,197,507	2.60	4.14
20	Plant Unit Info	1,618.0	891,263	74.0%	74.7%	90.9%	6,294			5,609,775	23,197,507	2.60	
21	Okeechobee PV Solar												
22	Solar		14,662					N/A	N/A	N/A	N/A	N/A	N/A
23	Plant Unit Info	74.5	14,662	26.5%	N/A	26.5%	N/A						
24	Orange Blossom PV Solar												
25	Solar		14,731					N/A	N/A	N/A	N/A	N/A	N/A
26	Plant Unit Info	74.5	14,731	26.6%	N/A	26.6%	N/A						
27	Palm Bay PV Solar												
28	Solar		14,759					N/A	N/A	N/A	N/A	N/A	N/A
29	Plant Unit Info	74.5	14,759	26.6%	N/A	26.6%	N/A						
30	PEEC												
31	Gas		847,839				6,341	5,376,291	1,000,000	5,376,291	22,352,931	2.64	4.16
32	Plant Unit Info	1,254.0	847,839	90.9%	93.0%	90.9%	6,341			5,376,291	22,352,931	2.64	
33	Pelican PV Solar												
34	Solar		14,738					N/A	N/A	N/A	N/A	N/A	N/A
35	Plant Unit Info	74.5	14,738	26.6%	N/A	26.6%	N/A						
36	Pioneer Trail PV Solar												
37	Solar		13,603					N/A	N/A	N/A	N/A	N/A	N/A
38	Plant Unit Info	74.5	13,603	24.5%	N/A	24.5%	N/A						
39	Riviera 5												
40	Light Oil		0					0	0	0	0	0.00	0.00
41	Gas		753,860				6,668	5,026,668	1,000,000	5,026,668	20,786,247	2.76	4.14
42	Plant Unit Info	1,308.0	753,860	77.5%	93.4%	77.5%	6,668			5,026,668	20,786,247	2.76	
43	Rodeo PV Solar												

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1	Solar		14,491					N/A	N/A	N/A	N/A	N/A	N/A
2	Plant Unit Info	74.5	14,491	26.1%	N/A	26.1%	N/A						
3	Sabal Palm PV Solar												
4	Solar		14,753					N/A	N/A	N/A	N/A	N/A	N/A
5	Plant Unit Info	74.5	14,753	26.6%	N/A	26.6%	N/A						
6	Sanford 4												
7	Gas		323,091				7,322	2,365,780	1,000,000	2,365,780	9,846,446	3.05	4.16
8	Plant Unit Info	1,147.0	323,091	37.9%	94.1%	37.9%	7,322			2,365,780	9,846,446	3.05	
9	Sanford 5												
10	Gas		432,553				7,141	3,088,724	1,000,000	3,088,724	12,845,168	2.97	4.16
11	Plant Unit Info	1,147.0	432,553	50.7%	94.1%	50.7%	7,141			3,088,724	12,845,168	2.97	
12	Scherer 4												
13	Coal		189,076				11,394	126,722	17,000,000	2,154,272	5,478,787	2.90	43.23
14	Plant Unit Info	636.0	189,076	40.0%	92.2%	40.0%	11,394			2,154,272	5,478,787	2.90	
15	Southfork PV Solar												
16	Solar		16,729					N/A	N/A	N/A	N/A	N/A	N/A
17	Plant Unit Info	74.5	16,729	30.2%	N/A	30.2%	N/A						
18	Space Coast												
19	Solar		1,451					N/A	N/A	N/A	N/A	N/A	N/A
20	Plant Unit Info	10.0	1,451	19.5%	N/A	19.5%	N/A						
21	St Lucie 1												
22	Nuclear		711,586				10,560	7,514,275	1,000,000	7,514,275	3,522,692	0.50	0.47
23	Plant Unit Info	981.0	711,586	97.5%	97.5%	97.5%	10,560			7,514,275	3,522,692	0.50	
24	St Lucie 2												
25	Nuclear		589,637				10,496	6,188,655	1,000,000	6,188,655	2,895,672	0.49	0.47
26	Plant Unit Info	840.0	589,637	94.4%	94.4%	97.5%	10,496			6,188,655	2,895,672	0.49	
27	Sunshine Gateway PV Solar												
28	Solar		14,347					N/A	N/A	N/A	N/A	N/A	N/A
29	Plant Unit Info	74.5	14,347	25.9%	N/A	25.9%	N/A						
30	Sweet Bay PV Solar												
31	Solar		13,027					N/A	N/A	N/A	N/A	N/A	N/A
32	Plant Unit Info	74.5	13,027	23.5%	N/A	23.5%	N/A						
33	Trailside PV Solar												
34	Solar		14,059					N/A	N/A	N/A	N/A	N/A	N/A
35	Plant Unit Info	74.5	14,059	25.4%	N/A	25.4%	N/A						
36	Turkey Point 3												
37	Nuclear		156,691				10,818	1,695,148	1,000,000	1,695,148	816,000	0.52	0.48
38	Plant Unit Info	837.0	156,691	25.2%	25.2%	97.5%	10,818			1,695,148	816,000	0.52	
39	Turkey Point 4												
40	Nuclear		610,080				10,767	6,568,671	1,000,000	6,568,671	3,790,780	0.62	0.58
41	Plant Unit Info	841.0	610,080	97.5%	97.5%	97.5%	10,767			6,568,671	3,790,780	0.62	
42	Turkey Point 5												
43	Light Oil		0					0	0	0	0	0.00	0.00

ESTIMATED FOR THE PERIOD OF: JANUARY 2021 THROUGH DECEMBER 2021

(1) Line No.	(2) PLANT UNIT	(3) Net Capability (MW)	(4) Net Generation (MWH)	(5) Capacity Factor	(6) Equivalent Availability Factor	(7) Net Output Factor	(8) Avg Net Heat Rate (BTU/KWH)	(9) Fuel Burned (Units)	(10) Fuel Heat Value (BTU/Unit)	(11) Fuel Burned (MMBTU)	(12) As Burned Fuel Cost ($)	(13) Fuel Cost per KWH (cents/KWH)	(14) Cost of Fuel ($/Unit)
1	Gas		205,687				7,767	1,597,580	1,000,000	1,597,580	6,652,675	3.23	4.16
2	Plant Unit Info	1,256.0	205,687	22.0%	93.9%	22.0%	7,767			1,597,580	6,652,675	3.23	
3	Twin Lakes PV Solar												
4	Solar		13,886					N/A	N/A	N/A	N/A	N/A	N/A
5	Plant Unit Info	74.5	13,886	25.1%	N/A	25.1%	N/A						
6	Union Springs PV Solar												
7	Solar		13,928					N/A	N/A	N/A	N/A	N/A	N/A
8	Plant Unit Info	74.5	13,928	25.1%	N/A	25.1%	N/A						
9	WCEC 01												
10	Light Oil		0					0	0	0	0	0.00	0.00
11	Gas		507,122				6,707	3,401,454	1,000,000	3,401,454	13,823,389	2.73	4.06
12	Plant Unit Info	1,223.0	507,122	55.7%	61.5%	82.3%	6,707			3,401,454	13,823,389	2.73	
13	WCEC 02												
14	Light Oil		0					0	0	0	0	0.00	0.00
15	Gas		802,753				6,641	5,331,258	1,000,000	5,331,258	21,659,661	2.70	4.06
16	Plant Unit Info	1,223.0	802,753	88.2%	93.7%	88.2%	6,641			5,331,258	21,659,661	2.70	
17	WCEC 03												
18	Light Oil		0					0	0	0	0	0.00	0.00
19	Gas		743,604				6,680	4,966,931	1,000,000	4,966,931	20,176,654	2.71	4.06
20	Plant Unit Info	1,228.0	743,604	81.4%	87.3%	87.1%	6,680			4,966,931	20,176,654	2.71	
21	Wildflower PV Solar												
22	Solar		15,474					N/A	N/A	N/A	N/A	N/A	N/A
23	Plant Unit Info	74.5	15,474	27.9%	N/A	27.9%	N/A						
24	Willow PV Solar												
25	Solar		14,089					N/A	N/A	N/A	N/A	N/A	N/A
26	Plant Unit Info	74.5	14,089	25.4%	N/A	25.4%	N/A						
27	System Totals												
28	Plant Unit Info	28,389	10,689,766				7,319			78,242,546	239,627,588	2.24	
29													
30													
31													
32													
33													
34													
35													
36													
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41													
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43													

ESTIMATED FOR THE PERIOD OF: JANUARY 2021 THROUGH DECEMBER 2021

(1) Line No.	(2) PLANT UNIT	(3) Net Capability (MW)	(4) Net Generation (MWH)	(5) Capacity Factor	(6) Equivalent Availability Factor	(7) Net Output Factor	(8) Avg Net Heat Rate (BTU/KWH)	(9) Fuel Burned (Units)	(10) Fuel Heat Value (BTU/Unit)	(11) Fuel Burned (MMBTU)	(12) As Burned Fuel Cost ($)	(13) Fuel Cost per KWH (cents/KWH)	(14) Cost of Fuel ($/Unit)
1	**Nov - 2021**												
2	Babcock PV Solar												
3	Solar		12,647					N/A	N/A	N/A	N/A	N/A	N/A
4	Plant Unit Info	74.5	12,647	23.6%	N/A	23.6%	N/A						
5	Babcock Preserve PV Solar												
6	Solar		13,755					N/A	N/A	N/A	N/A	N/A	N/A
7	Plant Unit Info	74.5	13,755	25.6%	N/A	25.6%	N/A						
8	Barefoot PV Solar												
9	Solar		12,750					N/A	N/A	N/A	N/A	N/A	N/A
10	Plant Unit Info	74.5	12,750	23.8%	N/A	23.8%	N/A						
11	Blue Cypress PV Solar												
12	Solar		13,101					N/A	N/A	N/A	N/A	N/A	N/A
13	Plant Unit Info	74.5	13,101	24.4%	N/A	24.4%	N/A						
14	Blue Heron PV Solar												
15	Solar		13,755					N/A	N/A	N/A	N/A	N/A	N/A
16	Plant Unit Info	74.5	13,755	25.6%	N/A	25.6%	N/A						
17	CCEC 3												
18	Light Oil		0					0	0	0	0	0.00	0.00
19	Gas		524,795				6,727	3,530,200	1,000,000	3,530,200	16,106,236	3.07	4.56
20	Plant Unit Info	1,326.0	524,795	55.0%	80.1%	62.9%	6,727			3,530,200	16,106,236	3.07	
21	Cattle Ranch PV Solar												
22	Solar		12,159					N/A	N/A	N/A	N/A	N/A	N/A
23	Plant Unit Info	74.5	12,159	22.7%	N/A	22.7%	N/A						
24	Citrus PV Solar												
25	Solar		12,570					N/A	N/A	N/A	N/A	N/A	N/A
26	Plant Unit Info	74.5	12,570	23.4%	N/A	23.4%	N/A						
27	Coral Farms PV Solar												
28	Solar		13,212					N/A	N/A	N/A	N/A	N/A	N/A
29	Plant Unit Info	74.5	13,212	24.6%	N/A	24.6%	N/A						
30	Desoto Solar												
31	Solar		3,261					N/A	N/A	N/A	N/A	N/A	N/A
32	Plant Unit Info	25.0	3,261	18.1%	N/A	18.1%	N/A						
33	Discovery PV Solar												
34	Solar		12,321					N/A	N/A	N/A	N/A	N/A	N/A
35	Plant Unit Info	74.5	12,321	23.0%	N/A	23.0%	N/A						
36	Egret PV Solar												
37	Solar		11,794					N/A	N/A	N/A	N/A	N/A	N/A
38	Plant Unit Info	74.5	11,794	22.0%	N/A	22.0%	N/A						
39	Fort Drum PV Solar												
40	Solar		12,058					N/A	N/A	N/A	N/A	N/A	N/A
41	Plant Unit Info	74.5	12,058	22.5%	N/A	22.5%	N/A						
42	Fort Myers 2												
43	Gas		574,891				7,393	4,250,369	1,000,000	4,250,369	19,391,789	3.37	4.56

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(1) Line No.	(2) PLANT UNIT	(3) Net Capability (MW)	(4) Net Generation (MWH)	(5) Capacity Factor	(6) Equivalent Availability Factor	(7) Net Output Factor	(8) Avg Net Heat Rate (BTU/KWH)	(9) Fuel Burned (Units)	(10) Fuel Heat Value (BTU/Unit)	(11) Fuel Burned (MMBTU)	(12) As Burned Fuel Cost ($)	(13) Fuel Cost per KWH (cents/KWH)	(14) Cost of Fuel ($/Unit)
1	Plant Unit Info	1,770.0	574,891	45.1%	71.6%	58.0%	7,393			4,250,369	19,391,789	3.37	
2	Fort Myers 3A												
3	Light Oil		0					0	0	0	0	0.00	0.00
4	Gas		0					0	0	0	0	0.00	0.00
5	Plant Unit Info	189.0	0	N/A	93.7%	N/A	N/A						
6	Fort Myers 3B												
7	Light Oil		0					0	0	0	0	0.00	0.00
8	Gas		0					0	0	0	0	0.00	0.00
9	Plant Unit Info	193.0	0	N/A	93.7%	N/A	N/A						
10	Fort Myers 3C												
11	Light Oil		0					0	0	0	0	0.00	0.00
12	Gas		0					0	0	0	0	0.00	0.00
13	Plant Unit Info	221.0	0	N/A	93.7%	N/A	N/A						
14	Fort Myers 3D												
15	Light Oil		0					0	0	0	0	0.00	0.00
16	Gas		0					0	0	0	0	0.00	0.00
17	Plant Unit Info	221.0	0	N/A	93.7%	N/A	N/A						
18	Echo River PV Solar												
19	Solar		13,329					N/A	N/A	N/A	N/A	N/A	N/A
20	Plant Unit Info	74.5	13,329	24.9%	N/A	24.9%	N/A						
21	Hammock PV Solar												
22	Solar		14,053					N/A	N/A	N/A	N/A	N/A	N/A
23	Plant Unit Info	74.5	14,053	26.2%	N/A	26.2%	N/A						
24	Hibiscus PV Solar												
25	Solar		12,211					N/A	N/A	N/A	N/A	N/A	N/A
26	Plant Unit Info	74.5	12,211	22.8%	N/A	22.8%	N/A						
27	Horizon PV Solar												
28	Solar		13,335					N/A	N/A	N/A	N/A	N/A	N/A
29	Plant Unit Info	74.5	13,335	24.9%	N/A	24.9%	N/A						
30	Indian River PV Solar												
31	Solar		13,089					N/A	N/A	N/A	N/A	N/A	N/A
32	Plant Unit Info	74.5	13,089	24.4%	N/A	24.4%	N/A						
33	Indiantown												
34	Plant Unit Info	0.0	0	N/A	N/A	N/A	N/A						
35	Interstate PV Solar												
36	Solar		12,422					N/A	N/A	N/A	N/A	N/A	N/A
37	Plant Unit Info	74.5	12,422	23.2%	N/A	23.2%	N/A						
38	Lakeside PV Solar												
39	Solar		13,581					N/A	N/A	N/A	N/A	N/A	N/A
40	Plant Unit Info	74.5	13,581	25.3%	N/A	25.3%	N/A						
41	Lauderdale 6A												
42	Light Oil		0					0	0	0	0	0.00	0.00
43	Gas		3,030				10,599	32,116	1,000,000	32,116	147,002	4.85	4.58

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(1) Line No.	(2) PLANT UNIT	(3) Net Capability (MW)	(4) Net Generation (MWH)	(5) Capacity Factor	(6) Equivalent Availability Factor	(7) Net Output Factor	(8) Avg Net Heat Rate (BTU/KWH)	(9) Fuel Burned (Units)	(10) Fuel Heat Value (BTU/Unit)	(11) Fuel Burned (MMBTU)	(12) As Burned Fuel Cost ($)	(13) Fuel Cost per KWH (cents/KWH)	(14) Cost of Fuel ($/Unit)
1	Plant Unit Info	218.0	3,030	1.9%	94.0%	1.9%	10,599			32,116	147,002	4.85	
2	Lauderdale 6B												
3	Light Oil		0					0	0	0	0	0.00	0.00
4	Gas		2,020				10,600	21,411	1,000,000	21,411	98,180	4.86	4.59
5	Plant Unit Info	218.0	2,020	1.3%	94.0%	1.3%	10,600			21,411	98,180	4.86	
6	Lauderdale 6C												
7	Light Oil		0					0	0	0	0	0.00	0.00
8	Gas		3,030				10,599	32,116	1,000,000	32,116	147,002	4.85	4.58
9	Plant Unit Info	218.0	3,030	1.9%	94.0%	1.9%	10,599			32,116	147,002	4.85	
10	Lauderdale 6D												
11	Light Oil		0					0	0	0	0	0.00	0.00
12	Gas		3,030				10,599	32,116	1,000,000	32,116	147,002	4.85	4.58
13	Plant Unit Info	218.0	3,030	1.9%	94.0%	1.9%	10,599			32,116	147,002	4.85	
14	Lauderdale 6E												
15	Light Oil		0					0	0	0	0	0.00	0.00
16	Gas		4,040				10,600	42,822	1,000,000	42,822	196,021	4.85	4.58
17	Plant Unit Info	218.0	4,040	2.6%	94.0%	2.6%	10,600			42,822	196,021	4.85	
18	Loggerhead PV Solar												
19	Solar		13,286					N/A	N/A	N/A	N/A	N/A	N/A
20	Plant Unit Info	74.5	13,286	24.8%	N/A	24.8%	N/A						
21	Magnolia PV Solar												
22	Solar		11,880					N/A	N/A	N/A	N/A	N/A	N/A
23	Plant Unit Info	74.5	11,880	22.2%	N/A	22.2%	N/A						
24	Manatee 1												
25	Heavy Oil		-					0	0	0	0	0.00	0.00
26	Gas		0					0	0	0	0	0.00	0.00
27	Plant Unit Info	797.0	0	N/A	N/A	N/A	N/A						
28	Manatee 2												
29	Heavy Oil		-					0	0	0	0	0.00	0.00
30	Gas		0					0	0	0	0	0.00	0.00
31	Plant Unit Info	797.0	0	N/A	N/A	N/A	N/A						
32	Manatee 3												
33	Gas		202,138				7,801	1,576,864	1,000,000	1,576,864	7,118,376	3.52	4.51
34	Plant Unit Info	1,254.0	202,138	22.4%	93.9%	22.4%	7,801			1,576,864	7,118,376	3.52	
35	Manatee PV Solar												
36	Solar		12,714					N/A	N/A	N/A	N/A	N/A	N/A
37	Plant Unit Info	74.5	12,714	23.7%	N/A	23.7%	N/A						
38	Martin 3												
39	Gas		21,703				9,077	197,002	1,000,000	197,002	891,484	4.11	4.53
40	Plant Unit Info	492.0	21,703	6.1%	93.9%	6.1%	9,077			197,002	891,484	4.11	
41	Martin 4												
42	Gas		19,981				8,581	171,448	1,000,000	171,448	776,816	3.89	4.53
43	Plant Unit Info	492.0	19,981	5.6%	93.9%	5.6%	8,581			171,448	776,816	3.89	

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1	Martin 8 Solar												
2	Solar		6,510					N/A	N/A	N/A	N/A	N/A	N/A
3	Plant Unit Info	75.0	6,510	12.1%	N/A	12.1%	N/A						
4	Martin 8												
5	Light Oil		0					0	0	0	0	0.00	0.00
6	Gas		107,247				7,991	857,052	1,000,000	857,052	3,874,037	3.61	4.52
7	Plant Unit Info	1,258.0	107,247	11.8%	93.5%	11.8%	7,991			857,052	3,874,037	3.61	
8	Miami-Dade PV Solar												
9	Solar		13,058					N/A	N/A	N/A	N/A	N/A	N/A
10	Plant Unit Info	74.5	13,058	24.3%	N/A	24.3%	N/A						
11	Nassau PV Solar												
12	Solar		11,739					N/A	N/A	N/A	N/A	N/A	N/A
13	Plant Unit Info	74.5	11,739	21.9%	N/A	21.9%	N/A						
14	Northern Preserve PV Solar												
15	Solar		11,955					N/A	N/A	N/A	N/A	N/A	N/A
16	Plant Unit Info	74.5	11,955	22.3%	N/A	22.3%	N/A						
17	Okeechobee 1												
18	Light Oil		0					0	0	0	0	0.00	0.00
19	Gas		879,891				6,309	5,550,954	1,000,000	5,550,954	25,302,114	2.88	4.56
20	Plant Unit Info	1,655.1	879,891	73.8%	80.8%	84.3%	6,309			5,550,954	25,302,114	2.88	
21	Okeechobee PV Solar												
22	Solar		12,724					N/A	N/A	N/A	N/A	N/A	N/A
23	Plant Unit Info	74.5	12,724	23.7%	N/A	23.7%	N/A						
24	Orange Blossom PV Solar												
25	Solar		13,555					N/A	N/A	N/A	N/A	N/A	N/A
26	Plant Unit Info	74.5	13,555	25.3%	N/A	25.3%	N/A						
27	Palm Bay PV Solar												
28	Solar		13,581					N/A	N/A	N/A	N/A	N/A	N/A
29	Plant Unit Info	74.5	13,581	25.3%	N/A	25.3%	N/A						
30	PEEC												
31	Gas		828,588				6,340	5,252,920	1,000,000	5,252,920	23,965,465	2.89	4.56
32	Plant Unit Info	1,283.0	828,588	89.7%	92.8%	89.7%	6,340			5,252,920	23,965,465	2.89	
33	Pelican PV Solar												
34	Solar		13,561					N/A	N/A	N/A	N/A	N/A	N/A
35	Plant Unit Info	74.5	13,561	25.3%	N/A	25.3%	N/A						
36	Pioneer Trail PV Solar												
37	Solar		12,082					N/A	N/A	N/A	N/A	N/A	N/A
38	Plant Unit Info	74.5	12,082	22.5%	N/A	22.5%	N/A						
39	Riviera 5												
40	Light Oil		0					0	0	0	0	0.00	0.00
41	Gas		610,677				6,705	4,094,287	1,000,000	4,094,287	18,660,940	3.06	4.56
42	Plant Unit Info	1,326.0	610,677	64.0%	93.2%	64.0%	6,705			4,094,287	18,660,940	3.06	
43	Rodeo PV Solar												

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(1) Line No.	(2) PLANT UNIT	(3) Net Capability (MW)	(4) Net Generation (MWH)	(5) Capacity Factor	(6) Equivalent Availability Factor	(7) Net Output Factor	(8) Avg Net Heat Rate (BTU/KWH)	(9) Fuel Burned (Units)	(10) Fuel Heat Value (BTU/Unit)	(11) Fuel Burned (MMBTU)	(12) As Burned Fuel Cost ($)	(13) Fuel Cost per KWH (cents/KWH)	(14) Cost of Fuel ($/Unit)
1	Solar		12,347					N/A	N/A	N/A	N/A	N/A	N/A
2	Plant Unit Info	74.5	12,347	23.0%	N/A	23.0%	N/A						
3	Sabal Palm PV Solar												
4	Solar		13,576					N/A	N/A	N/A	N/A	N/A	N/A
5	Plant Unit Info	74.5	13,576	25.3%	N/A	25.3%	N/A						
6	Sanford 4												
7	Gas		46,423				7,478	347,140	1,000,000	347,140	1,587,642	3.42	4.57
8	Plant Unit Info	1,192.0	46,423	5.4%	94.1%	5.4%	7,478			347,140	1,587,642	3.42	
9	Sanford 5												
10	Gas		362,939				7,188	2,608,636	1,000,000	2,608,636	11,903,735	3.28	4.56
11	Plant Unit Info	1,192.0	362,939	42.3%	94.1%	42.3%	7,188			2,608,636	11,903,735	3.28	
12	Scherer 4												
13	Coal		174,225				11,453	117,378	17,000,000	1,995,419	5,084,560	2.92	43.32
14	Plant Unit Info	626.0	174,225	38.7%	92.2%	38.7%	11,453			1,995,419	5,084,560	2.92	
15	Southfork PV Solar												
16	Solar		14,045					N/A	N/A	N/A	N/A	N/A	N/A
17	Plant Unit Info	74.5	14,045	26.2%	N/A	26.2%	N/A						
18	Space Coast												
19	Solar		1,255					N/A	N/A	N/A	N/A	N/A	N/A
20	Plant Unit Info	10.0	1,255	17.4%	N/A	17.4%	N/A						
21	St Lucie 1												
22	Nuclear		704,121				10,328	7,272,374	1,000,000	7,272,374	3,409,289	0.48	0.47
23	Plant Unit Info	1,003.0	704,121	97.5%	97.5%	97.5%	10,328			7,272,374	3,409,289	0.48	
24	St Lucie 2												
25	Nuclear		603,399				10,257	6,188,882	1,000,000	6,188,882	2,895,778	0.48	0.47
26	Plant Unit Info	859.6	603,399	97.5%	97.5%	97.5%	10,257			6,188,882	2,895,778	0.48	
27	Sunshine Gateway PV Solar												
28	Solar		12,701					N/A	N/A	N/A	N/A	N/A	N/A
29	Plant Unit Info	74.5	12,701	23.7%	N/A	23.7%	N/A						
30	Sweet Bay PV Solar												
31	Solar		11,706					N/A	N/A	N/A	N/A	N/A	N/A
32	Plant Unit Info	74.5	11,706	21.8%	N/A	21.8%	N/A						
33	Trailside PV Solar												
34	Solar		11,980					N/A	N/A	N/A	N/A	N/A	N/A
35	Plant Unit Info	74.5	11,980	22.3%	N/A	22.3%	N/A						
36	Turkey Point 3												
37	Nuclear		482,400				10,541	5,085,123	1,000,000	5,085,123	2,469,046	0.51	0.49
38	Plant Unit Info	859.0	482,400	78.0%	78.0%	97.5%	10,541			5,085,123	2,469,046	0.51	
39	Turkey Point 4												
40	Nuclear		609,336				10,432	6,356,593	1,000,000	6,356,593	3,668,390	0.60	0.58
41	Plant Unit Info	868.0	609,336	97.5%	97.5%	97.5%	10,432			6,356,593	3,668,390	0.60	
42	Turkey Point 5												
43	Light Oil		0					0	0	0	0	0.00	0.00

ESTIMATED FOR THE PERIOD OF: JANUARY 2021 THROUGH DECEMBER 2021

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.	PLANT UNIT	Net Capability (MW)	Net Generation (MWH)	Capacity Factor	Equivalent Availability Factor	Net Output Factor	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost ($)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel ($/Unit)
1	Gas		84,775				7,660	649,418	1,000,000	649,418	2,966,344	3.50	4.57
2	Plant Unit Info	1,294.0	84,775	9.1%	65.7%	12.4%	7,660			649,418	2,966,344	3.50	
3	Twin Lakes PV Solar												
4	Solar		11,832					N/A	N/A	N/A	N/A	N/A	N/A
5	Plant Unit Info	74.5	11,832	22.1%	N/A	22.1%	N/A						
6	Union Springs PV Solar												
7	Solar		11,868					N/A	N/A	N/A	N/A	N/A	N/A
8	Plant Unit Info	74.5	11,868	22.1%	N/A	22.1%	N/A						
9	WCEC 01												
10	Light Oil		0					0	0	0	0	0.00	0.00
11	Gas		560,751				6,758	3,789,528	1,000,000	3,789,528	17,116,261	3.05	4.52
12	Plant Unit Info	1,248.0	560,751	62.4%	93.7%	62.4%	6,758			3,789,528	17,116,261	3.05	
13	WCEC 02												
14	Light Oil		0					0	0	0	0	0.00	0.00
15	Gas		638,508				6,733	4,298,760	1,000,000	4,298,760	19,418,892	3.04	4.52
16	Plant Unit Info	1,248.0	638,508	71.1%	93.7%	71.1%	6,733			4,298,760	19,418,892	3.04	
17	WCEC 03												
18	Light Oil		0					0	0	0	0	0.00	0.00
19	Gas		494,938				6,721	3,326,348	1,000,000	3,326,348	15,024,963	3.04	4.52
20	Plant Unit Info	1,254.0	494,938	54.8%	60.4%	82.4%	6,721			3,326,348	15,024,963	3.04	
21	Wildflower PV Solar												
22	Solar		13,864					N/A	N/A	N/A	N/A	N/A	N/A
23	Plant Unit Info	74.5	13,864	25.9%	N/A	25.9%	N/A						
24	Willow PV Solar												
25	Solar		12,005					N/A	N/A	N/A	N/A	N/A	N/A
26	Plant Unit Info	74.5	12,005	22.4%	N/A	22.4%	N/A						
27	System Totals												
28	Plant Unit Info	29,023	9,056,103				7,460			67,559,898	202,367,365	2.23	
29													
30													
31													
32													
33													
34													
35													
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41													
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43													

ESTIMATED FOR THE PERIOD OF: JANUARY 2021 THROUGH DECEMBER 2021

(1) Line No.	(2) PLANT UNIT	(3) Net Capability (MW)	(4) Net Generation (MWH)	(5) Capacity Factor	(6) Equivalent Availability Factor	(7) Net Output Factor	(8) Avg Net Heat Rate (BTU/KWH)	(9) Fuel Burned (Units)	(10) Fuel Heat Value (BTU/Unit)	(11) Fuel Burned (MMBTU)	(12) As Burned Fuel Cost ($)	(13) Fuel Cost per KWH (cents/KWH)	(14) Cost of Fuel ($/Unit)
1	**Dec - 2021**												
2	Babcock PV Solar												
3	Solar		11,786					N/A	N/A	N/A	N/A	N/A	N/A
4	Plant Unit Info	74.5	11,786	21.3%	N/A	21.3%	N/A						
5	Babcock Preserve PV Solar												
6	Solar		12,564					N/A	N/A	N/A	N/A	N/A	N/A
7	Plant Unit Info	74.5	12,564	22.7%	N/A	22.7%	N/A						
8	Barefoot PV Solar												
9	Solar		11,620					N/A	N/A	N/A	N/A	N/A	N/A
10	Plant Unit Info	74.5	11,620	21.0%	N/A	21.0%	N/A						
11	Blue Cypress PV Solar												
12	Solar		12,043					N/A	N/A	N/A	N/A	N/A	N/A
13	Plant Unit Info	74.5	12,043	21.7%	N/A	21.7%	N/A						
14	Blue Heron PV Solar												
15	Solar		12,564					N/A	N/A	N/A	N/A	N/A	N/A
16	Plant Unit Info	74.5	12,564	22.7%	N/A	22.7%	N/A						
17	CCEC 3												
18	Light Oil		0					0	0	0	0	0.00	0.00
19	Gas		485,762				6,766	3,286,896	1,000,000	3,286,896	15,577,260	3.21	4.74
20	Plant Unit Info	1,326.0	485,762	49.2%	84.8%	53.6%	6,766			3,286,896	15,577,260	3.21	
21	Cattle Ranch PV Solar												
22	Solar		10,595					N/A	N/A	N/A	N/A	N/A	N/A
23	Plant Unit Info	74.5	10,595	19.1%	N/A	19.1%	N/A						
24	Citrus PV Solar												
25	Solar		11,757					N/A	N/A	N/A	N/A	N/A	N/A
26	Plant Unit Info	74.5	11,757	21.2%	N/A	21.2%	N/A						
27	Coral Farms PV Solar												
28	Solar		12,061					N/A	N/A	N/A	N/A	N/A	N/A
29	Plant Unit Info	74.5	12,061	21.8%	N/A	21.8%	N/A						
30	Desoto Solar												
31	Solar		2,906					N/A	N/A	N/A	N/A	N/A	N/A
32	Plant Unit Info	25.0	2,906	15.6%	N/A	15.6%	N/A						
33	Discovery PV Solar												
34	Solar		11,255					N/A	N/A	N/A	N/A	N/A	N/A
35	Plant Unit Info	74.5	11,255	20.3%	N/A	20.3%	N/A						
36	Egret PV Solar												
37	Solar		10,278					N/A	N/A	N/A	N/A	N/A	N/A
38	Plant Unit Info	74.5	10,278	18.5%	N/A	18.5%	N/A						
39	Fort Drum PV Solar												
40	Solar		11,014					N/A	N/A	N/A	N/A	N/A	N/A
41	Plant Unit Info	74.5	11,014	19.9%	N/A	19.9%	N/A						
42	Fort Myers 2												
43	Gas		583,593				7,423	4,332,024	1,000,000	4,332,024	20,531,080	3.52	4.74

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(1) Line No.	(2) PLANT UNIT	(3) Net Capability (MW)	(4) Net Generation (MWH)	(5) Capacity Factor	(6) Equivalent Availability Factor	(7) Net Output Factor	(8) Avg Net Heat Rate (BTU/KWH)	(9) Fuel Burned (Units)	(10) Fuel Heat Value (BTU/Unit)	(11) Fuel Burned (MMBTU)	(12) As Burned Fuel Cost ($)	(13) Fuel Cost per KWH (cents/KWH)	(14) Cost of Fuel ($/Unit)
1	Plant Unit Info	1,770.0	583,593	44.3%	93.8%	44.3%	7,423			4,332,024	20,531,080	3.52	
2	Fort Myers 3A												
3	Light Oil		0					0	0	0	0	0.00	0.00
4	Gas		0					0	0	0	0	0.00	0.00
5	Plant Unit Info	189.0	0	N/A	93.7%	N/A	N/A						
6	Fort Myers 3B												
7	Light Oil		0					0	0	0	0	0.00	0.00
8	Gas		0					0	0	0	0	0.00	0.00
9	Plant Unit Info	193.0	0	N/A	93.7%	N/A	N/A						
10	Fort Myers 3C												
11	Light Oil		0					0	0	0	0	0.00	0.00
12	Gas		0					0	0	0	0	0.00	0.00
13	Plant Unit Info	221.0	0	N/A	93.7%	N/A	N/A						
14	Fort Myers 3D												
15	Light Oil		0					0	0	0	0	0.00	0.00
16	Gas		0					0	0	0	0	0.00	0.00
17	Plant Unit Info	221.0	0	N/A	93.7%	N/A	N/A						
18	Echo River PV Solar												
19	Solar		10,814					N/A	N/A	N/A	N/A	N/A	N/A
20	Plant Unit Info	74.5	10,814	19.5%	N/A	19.5%	N/A						
21	Hammock PV Solar												
22	Solar		12,892					N/A	N/A	N/A	N/A	N/A	N/A
23	Plant Unit Info	74.5	12,892	23.3%	N/A	23.3%	N/A						
24	Hibiscus PV Solar												
25	Solar		11,247					N/A	N/A	N/A	N/A	N/A	N/A
26	Plant Unit Info	74.5	11,247	20.3%	N/A	20.3%	N/A						
27	Horizon PV Solar												
28	Solar		12,148					N/A	N/A	N/A	N/A	N/A	N/A
29	Plant Unit Info	74.5	12,148	21.9%	N/A	21.9%	N/A						
30	Indian River PV Solar												
31	Solar		12,031					N/A	N/A	N/A	N/A	N/A	N/A
32	Plant Unit Info	74.5	12,031	21.7%	N/A	21.7%	N/A						
33	Indiantown												
34	Plant Unit Info	0.0	0	N/A	N/A	N/A	N/A						
35	Interstate PV Solar												
36	Solar		11,611					N/A	N/A	N/A	N/A	N/A	N/A
37	Plant Unit Info	74.5	11,611	21.0%	N/A	21.0%	N/A						
38	Lakeside PV Solar												
39	Solar		12,406					N/A	N/A	N/A	N/A	N/A	N/A
40	Plant Unit Info	74.5	12,406	22.4%	N/A	22.4%	N/A						
41	Lauderdale 6A												
42	Light Oil		0					0	0	0	0	0.00	0.00
43	Gas		0					0	0	0	0	0.00	0.00

ESTIMATED FOR THE PERIOD OF: JANUARY 2021 THROUGH DECEMBER 2021

(1) Line No.	(2) PLANT UNIT	(3) Net Capability (MW)	(4) Net Generation (MWH)	(5) Capacity Factor	(6) Equivalent Availability Factor	(7) Net Output Factor	(8) Avg Net Heat Rate (BTU/KWH)	(9) Fuel Burned (Units)	(10) Fuel Heat Value (BTU/Unit)	(11) Fuel Burned (MMBTU)	(12) As Burned Fuel Cost ($)	(13) Fuel Cost per KWH (cents/KWH)	(14) Cost of Fuel ($/Unit)
1	Plant Unit Info	218.0	0	N/A	94.0%	N/A	N/A						
2	Lauderdale 6B												
3	Light Oil		0					0	0	0	0	0.00	0.00
4	Gas		0					0	0	0	0	0.00	0.00
5	Plant Unit Info	218.0	0	N/A	94.0%	N/A	N/A						
6	Lauderdale 6C												
7	Light Oil		0					0	0	0	0	0.00	0.00
8	Gas		1,010				10,599	10,705	1,000,000	10,705	50,724	5.02	4.74
9	Plant Unit Info	218.0	1,010	0.6%	94.0%	0.6%	10,599			10,705	50,724	5.02	
10	Lauderdale 6D												
11	Light Oil		0					0	0	0	0	0.00	0.00
12	Gas		1,010				10,599	10,705	1,000,000	10,705	50,757	5.03	4.74
13	Plant Unit Info	218.0	1,010	0.6%	94.0%	0.6%	10,599			10,705	50,757	5.03	
14	Lauderdale 6E												
15	Light Oil		0					0	0	0	0	0.00	0.00
16	Gas		0					0	0	0	0	0.00	0.00
17	Plant Unit Info	218.0	0	N/A	94.0%	N/A	N/A						
18	Loggerhead PV Solar												
19	Solar		12,343					N/A	N/A	N/A	N/A	N/A	N/A
20	Plant Unit Info	74.5	12,343	22.3%	N/A	22.3%	N/A						
21	Magnolia PV Solar												
22	Solar		10,352					N/A	N/A	N/A	N/A	N/A	N/A
23	Plant Unit Info	74.5	10,352	18.7%	N/A	18.7%	N/A						
24	Manatee 1												
25	Heavy Oil		-					0	0	0	0	0.00	0.00
26	Gas		0					0	0	0	0	0.00	0.00
27	Plant Unit Info	797.0	0	N/A	N/A	N/A	N/A						
28	Manatee 2												
29	Heavy Oil		-					0	0	0	0	0.00	0.00
30	Gas		0					0	0	0	0	0.00	0.00
31	Plant Unit Info	797.0	0	N/A	N/A	N/A	N/A						
32	Manatee 3												
33	Gas		126,709				8,490	1,075,817	1,000,000	1,075,817	5,046,344	3.98	4.69
34	Plant Unit Info	1,254.0	126,709	13.6%	93.9%	13.6%	8,490			1,075,817	5,046,344	3.98	
35	Manatee PV Solar												
36	Solar		11,751					N/A	N/A	N/A	N/A	N/A	N/A
37	Plant Unit Info	74.5	11,751	21.2%	N/A	21.2%	N/A						
38	Martin 3												
39	Gas		132,621				7,775	1,031,140	1,000,000	1,031,140	4,837,670	3.65	4.69
40	Plant Unit Info	492.0	132,621	36.2%	93.9%	36.2%	7,775			1,031,140	4,837,670	3.65	
41	Martin 4												
42	Gas		3,368				10,915	36,762	1,000,000	36,762	172,639	5.13	4.70
43	Plant Unit Info	492.0	3,368	0.9%	93.9%	0.9%	10,915			36,762	172,639	5.13	

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(1) Line No.	(2) PLANT UNIT	(3) Net Capability (MW)	(4) Net Generation (MWH)	(5) Capacity Factor	(6) Equivalent Availability Factor	(7) Net Output Factor	(8) Avg Net Heat Rate (BTU/KWH)	(9) Fuel Burned (Units)	(10) Fuel Heat Value (BTU/Unit)	(11) Fuel Burned (MMBTU)	(12) As Burned Fuel Cost ($)	(13) Fuel Cost per KWH (cents/KWH)	(14) Cost of Fuel ($/Unit)
1	Martin 8 Solar												
2	Solar		5,425					N/A	N/A	N/A	N/A	N/A	N/A
3	Plant Unit Info	75.0	5,425	9.7%	N/A	9.7%	N/A						
4	Martin 8												
5	Light Oil		0					0	0	0	0	0.00	0.00
6	Gas		69,110				8,652	597,955	1,000,000	597,955	2,806,019	4.06	4.69
7	Plant Unit Info	1,258.0	69,110	7.4%	93.5%	7.4%	8,652			597,955	2,806,019	4.06	
8	Miami-Dade PV Solar												
9	Solar		12,413					N/A	N/A	N/A	N/A	N/A	N/A
10	Plant Unit Info	74.5	12,413	22.4%	N/A	22.4%	N/A						
11	Nassau PV Solar												
12	Solar		10,230					N/A	N/A	N/A	N/A	N/A	N/A
13	Plant Unit Info	74.5	10,230	18.5%	N/A	18.5%	N/A						
14	Northern Preserve PV Solar												
15	Solar		10,920					N/A	N/A	N/A	N/A	N/A	N/A
16	Plant Unit Info	74.5	10,920	19.7%	N/A	19.7%	N/A						
17	Okeechobee 1												
18	Light Oil		0					0	0	0	0	0.00	0.00
19	Gas		1,011,981				6,308	6,384,025	1,000,000	6,384,025	30,263,509	2.99	4.74
20	Plant Unit Info	1,655.1	1,011,981	82.2%	93.0%	82.2%	6,308			6,384,025	30,263,509	2.99	
21	Okeechobee PV Solar												
22	Solar		11,539					N/A	N/A	N/A	N/A	N/A	N/A
23	Plant Unit Info	74.5	11,539	20.8%	N/A	20.8%	N/A						
24	Orange Blossom PV Solar												
25	Solar		12,382					N/A	N/A	N/A	N/A	N/A	N/A
26	Plant Unit Info	74.5	12,382	22.3%	N/A	22.3%	N/A						
27	Palm Bay PV Solar												
28	Solar		12,406					N/A	N/A	N/A	N/A	N/A	N/A
29	Plant Unit Info	74.5	12,406	22.4%	N/A	22.4%	N/A						
30	PEEC												
31	Gas		849,276				6,344	5,387,958	1,000,000	5,387,958	25,534,891	3.01	4.74
32	Plant Unit Info	1,283.0	849,276	89.0%	93.0%	89.0%	6,344			5,387,958	25,534,891	3.01	
33	Pelican PV Solar												
34	Solar		12,388					N/A	N/A	N/A	N/A	N/A	N/A
35	Plant Unit Info	74.5	12,388	22.4%	N/A	22.4%	N/A						
36	Pioneer Trail PV Solar												
37	Solar		11,197					N/A	N/A	N/A	N/A	N/A	N/A
38	Plant Unit Info	74.5	11,197	20.2%	N/A	20.2%	N/A						
39	Riviera 5												
40	Light Oil		0					0	0	0	0	0.00	0.00
41	Gas		517,330				6,762	3,498,121	1,000,000	3,498,121	16,581,054	3.21	4.74
42	Plant Unit Info	1,326.0	517,330	52.4%	93.4%	52.4%	6,762			3,498,121	16,581,054	3.21	
43	Rodeo PV Solar												

ESTIMATED FOR THE PERIOD OF: JANUARY 2021 THROUGH DECEMBER 2021

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.	PLANT UNIT	Net Capability (MW)	Net Generation (MWH)	Capacity Factor	Equivalent Availability Factor	Net Output Factor	Avg Net Heat Rate (BTU/KWH)	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost ($)	Fuel Cost per KWH (cents/KWH)	Cost of Fuel ($/Unit)
1	Solar		10,759					N/A	N/A	N/A	N/A	N/A	N/A
2	Plant Unit Info	74.5	10,759	19.4%	N/A	19.4%	N/A						
3	Sabal Palm PV Solar												
4	Solar		12,401					N/A	N/A	N/A	N/A	N/A	N/A
5	Plant Unit Info	74.5	12,401	22.4%	N/A	22.4%	N/A						
6	Sanford 4												
7	Gas		17,586				8,646	152,040	1,000,000	152,040	720,410	4.10	4.74
8	Plant Unit Info	1,192.0	17,586	2.0%	94.1%	2.0%	8,646			152,040	720,410	4.10	
9	Sanford 5												
10	Gas		335,120				7,304	2,447,647	1,000,000	2,447,647	11,600,148	3.46	4.74
11	Plant Unit Info	1,192.0	335,120	37.8%	94.1%	37.8%	7,304			2,447,647	11,600,148	3.46	
12	Scherer 4												
13	Coal		175,262				11,502	118,582	17,000,000	2,015,896	5,150,603	2.94	43.43
14	Plant Unit Info	626.0	175,262	37.6%	92.2%	37.6%	11,502			2,015,896	5,150,603	2.94	
15	Southfork PV Solar												
16	Solar		12,295					N/A	N/A	N/A	N/A	N/A	N/A
17	Plant Unit Info	74.5	12,295	22.2%	N/A	22.2%	N/A						
18	Space Coast												
19	Solar		1,170					N/A	N/A	N/A	N/A	N/A	N/A
20	Plant Unit Info	10.0	1,170	15.7%	N/A	15.7%	N/A						
21	St Lucie 1												
22	Nuclear		727,591				10,328	7,514,787	1,000,000	7,514,787	3,522,932	0.48	0.47
23	Plant Unit Info	1,003.0	727,591	97.5%	97.5%	97.5%	10,328			7,514,787	3,522,932	0.48	
24	St Lucie 2												
25	Nuclear		623,512				10,257	6,395,178	1,000,000	6,395,178	2,992,304	0.48	0.47
26	Plant Unit Info	859.6	623,512	97.5%	97.5%	97.5%	10,257			6,395,178	2,992,304	0.48	
27	Sunshine Gateway PV Solar												
28	Solar		10,864					N/A	N/A	N/A	N/A	N/A	N/A
29	Plant Unit Info	74.5	10,864	19.6%	N/A	19.6%	N/A						
30	Sweet Bay PV Solar												
31	Solar		10,858					N/A	N/A	N/A	N/A	N/A	N/A
32	Plant Unit Info	74.5	10,858	19.6%	N/A	19.6%	N/A						
33	Trailside PV Solar												
34	Solar		10,439					N/A	N/A	N/A	N/A	N/A	N/A
35	Plant Unit Info	74.5	10,439	18.8%	N/A	18.8%	N/A						
36	Turkey Point 3												
37	Nuclear		623,100				10,541	6,568,284	1,000,000	6,568,284	3,189,184	0.51	0.49
38	Plant Unit Info	859.0	623,100	97.5%	97.5%	97.5%	10,541			6,568,284	3,189,184	0.51	
39	Turkey Point 4												
40	Nuclear		629,647				10,432	6,568,480	1,000,000	6,568,480	3,790,670	0.60	0.58
41	Plant Unit Info	868.0	629,647	97.5%	97.5%	97.5%	10,432			6,568,480	3,790,670	0.60	
42	Turkey Point 5												
43	Light Oil		0					0	0	0	0	0.00	0.00

ESTIMATED FOR THE PERIOD OF: JANUARY 2021 THROUGH DECEMBER 2021

Line No. (1)	PLANT UNIT (2)	Net Capability (MW) (3)	Net Generation (MWH) (4)	Capacity Factor (5)	Equivalent Availability Factor (6)	Net Output Factor (7)	Avg Net Heat Rate (BTU/KWH) (8)	Fuel Burned (Units) (9)	Fuel Heat Value (BTU/Unit) (10)	Fuel Burned (MMBTU) (11)	As Burned Fuel Cost ($) (12)	Fuel Cost per KWH (cents/KWH) (13)	Cost of Fuel ($/Unit) (14)
1	Gas		242,746				7,474	1,814,199	1,000,000	1,814,199	8,598,580	3.54	4.74
2	Plant Unit Info	1,294.0	242,746	25.2%	60.9%	37.3%	7,474			1,814,199	8,598,580	3.54	
3	Twin Lakes PV Solar												
4	Solar		10,310					N/A	N/A	N/A	N/A	N/A	N/A
5	Plant Unit Info	74.5	10,310	18.6%	N/A	18.6%	N/A						
6	Union Springs PV Solar												
7	Solar		10,341					N/A	N/A	N/A	N/A	N/A	N/A
8	Plant Unit Info	74.5	10,341	18.7%	N/A	18.7%	N/A						
9	WCEC 01												
10	Light Oil		0					0	0	0	0	0.00	0.00
11	Gas		486,309				6,817	3,315,400	1,000,000	3,315,400	15,551,573	3.20	4.69
12	Plant Unit Info	1,248.0	486,309	52.4%	93.7%	52.4%	6,817			3,315,400	15,551,573	3.20	
13	WCEC 02												
14	Light Oil		0					0	0	0	0	0.00	0.00
15	Gas		563,081				6,785	3,820,651	1,000,000	3,820,651	17,921,557	3.18	4.69
16	Plant Unit Info	1,248.0	563,081	60.6%	93.7%	60.6%	6,785			3,820,651	17,921,557	3.18	
17	WCEC 03												
18	Light Oil		0					0	0	0	0	0.00	0.00
19	Gas		528,284				6,822	3,603,737	1,000,000	3,603,737	16,904,076	3.20	4.69
20	Plant Unit Info	1,254.0	528,284	56.6%	78.7%	66.7%	6,822			3,603,737	16,904,076	3.20	
21	Wildflower PV Solar												
22	Solar		12,684					N/A	N/A	N/A	N/A	N/A	N/A
23	Plant Unit Info	74.5	12,684	22.9%	N/A	22.9%	N/A						
24	Willow PV Solar												
25	Solar		10,461					N/A	N/A	N/A	N/A	N/A	N/A
26	Plant Unit Info	74.5	10,461	18.9%	N/A	18.9%	N/A						
27	System Totals												
28	Plant Unit Info	29,023	9,193,529				7,600			69,868,407	211,393,984	2.30	
29													
30													
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ESTIMATED FOR THE PERIOD OF: JANUARY 2021 THROUGH DECEMBER 2021

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
Line No.		Jan - 2021	Feb - 2021	Mar - 2021	Apr - 2021	May - 2021	Jun - 2021	Jul - 2021	Aug - 2021	Sep - 2021	Oct - 2021	Nov - 2021	Dec - 2021	2021
1	**#6 Heavy Oil (BBLS)**													
2	Purchases													
3	Units	0	0	0	0	0	0	0	0	0	0	0	0	0
4	Unit Cost	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
5	Amount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
6	Burned													
7	Units	0	3,060	0	464	0	10,805	12,728	24,713	15,538	5,401	0	0	72,709
8	Unit Cost	0.0000	68.5564	0.0000	68.5564	0.0000	68.5564	68.5564	68.5564	68.5564	68.5564	0.0000	0.0000	68.5564
9	Amount	$0	$209,793	$0	$31,804	$0	$740,763	$872,595	$1,694,222	$1,065,206	$370,290	$0	$0	$4,984,674
10	Ending Inventory													
11	Units	534,636	531,576	531,576	531,112	531,112	520,307	507,579	482,866	467,329	461,927	461,927	461,927	461,927
12	Unit Cost	68.5564	68.5564	68.5564	68.5564	68.5564	68.5564	68.5564	68.5564	68.5564	68.5564	68.5564	68.5564	68.5564
13	Amount	$36,652,760	$36,442,967	$36,442,967	$36,411,163	$36,411,163	$35,670,400	$34,797,805	$33,103,583	$32,038,377	$31,668,086	$31,668,086	$31,668,086	$31,668,086
14														
15	**#2 Light Oil (BBLS)**													
16	Purchases													
17	Units	0	0	0	0	0	0	0	0	0	0	0	0	0
18	Unit Cost	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
19	Amount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
20	Burned													
21	Units	0	4,021	0	0	0	0	5,242	6,996	2,528	0	0	0	18,788
22	Unit Cost	0.0000	76.0180	0.0000	0.0000	0.0000	0.0000	84.0713	80.5810	80.1530	0.0000	0.0000	0.0000	80.5206
23	Amount	$0	$305,702	$0	$0	$0	$0	$440,732	$563,777	$202,610	$0	$0	$0	$1,512,821
24	Ending Inventory													
25	Units	1,413,290	1,409,268	1,409,268	1,409,268	1,409,268	1,409,268	1,404,026	1,397,030	1,394,502	1,394,502	1,394,502	1,394,502	1,394,502
26	Unit Cost	90.2062	90.2467	90.2467	90.2467	90.2467	90.2467	90.2697	90.3183	90.3367	90.3367	90.3367	90.3367	90.3367
27	Amount	$127,487,499	$127,181,797	$127,181,797	$127,181,797	$127,181,797	$127,181,797	$126,741,065	$126,177,288	$125,974,678	$125,974,678	$125,974,678	$125,974,678	$125,974,678
28														
29	**Coal - Scherer (MMBTU)**													
30	Purchases													
31	Units	2,069,841	2,069,841	2,069,841	2,069,841	2,069,841	2,069,841	2,069,841	2,069,841	2,069,841	2,069,841	2,069,841	2,069,841	24,838,092
32	Unit Cost	2.5231	2.5263	2.5263	2.5162	2.5066	2.5194	2.5493	2.5621	2.5525	2.5491	2.5619	2.5746	2.5390
33	Amount	$5,222,416	$5,229,039	$5,229,039	$5,208,134	$5,188,263	$5,214,757	$5,276,646	$5,303,140	$5,283,269	$5,276,232	$5,302,726	$5,329,013	$63,062,674
34	Burned													
35	Units	2,068,506	1,908,230	2,117,950	2,038,652	2,069,231	2,051,993	2,125,320	2,195,543	2,097,080	2,154,272	1,995,419	2,015,896	24,838,092
36	Unit Cost	2.5365	2.5339	2.5320	2.5279	2.5225	2.5217	2.5287	2.5372	2.5412	2.5432	2.5481	2.5550	2.5356
37	Amount	$5,246,769	$4,835,208	$5,362,558	$5,153,610	$5,219,720	$5,174,604	$5,374,318	$5,570,548	$5,329,017	$5,478,787	$5,084,560	$5,150,603	$62,980,302
38	Ending Inventory													
39	Units	5,955,749	6,117,360	6,069,251	6,100,440	6,101,050	6,118,898	6,063,419	5,937,717	5,910,478	5,826,047	5,900,469	5,954,414	5,954,414
40	Unit Cost	2.5365	2.5339	2.5320	2.5279	2.5225	2.5217	2.5287	2.5372	2.5412	2.5432	2.5481	2.5550	2.5550
41	Amount	$15,106,768	$15,500,599	$15,367,081	$15,421,605	$15,390,149	$15,430,302	$15,332,630	$15,065,221	$15,019,473	$14,816,918	$15,035,083	$15,213,493	$15,213,493
42														

ESTIMATED FOR THE PERIOD OF: JANUARY 2021 THROUGH DECEMBER 2021

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
Line No.		Jan - 2021	Feb - 2021	Mar - 2021	Apr - 2021	May - 2021	Jun - 2021	Jul - 2021	Aug - 2021	Sep - 2021	Oct - 2021	Nov - 2021	Dec - 2021	2021
1	**Gas (MMBTU)**													
2	Burned													
3	Units	40,727,825	37,832,005	41,116,807	47,164,511	54,249,228	56,306,120	61,482,515	63,564,272	60,796,028	54,086,957	40,661,507	40,805,782	598,793,557
4	Unit Cost	4.8937	4.8134	4.7588	4.1993	4.0024	3.9537	3.9090	3.8827	3.8832	4.1184	4.5458	4.7236	4.2393
5	Amount	199,310,585	182,101,368	195,667,406	198,055,629	217,129,213	222,619,898	240,333,344	246,801,186	236,083,281	222,753,367	184,840,302	192,748,291	2,538,443,871
6	**Nuclear (Other)**													
7	Burned													
8	Units	27,046,729	24,429,304	27,046,729	21,083,802	23,895,442	26,174,118	27,046,589	26,221,435	19,985,463	21,966,749	24,902,972	27,046,729	296,846,059
9	Unit Cost	0.4937	0.4937	0.4937	0.4964	0.4927	0.4899	0.4899	0.4917	0.5072	0.5019	0.4996	0.4990	0.4955
10	Amount	13,353,863	12,061,554	13,353,863	10,466,978	11,773,620	12,823,430	13,250,878	12,892,762	10,137,554	11,025,143	12,442,503	13,495,090	147,077,238
11														
12														
13	Note: Totals may not add due to rounding.													
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15														
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ESTIMATED FOR THE PERIOD OF: JANUARY 2021 THROUGH DECEMBER 2021

(1) Line No.	(2) Month	(3) Sold To	(4) Type & Schedule	(5) Total KWH Sold (000)	(6) KWH from Own Generation (000)	(7) Fuel Cost (cents/KWH)	(8) Total Cost (cents/KWH)	(9) Total $ for Fuel Adj	(10) Total Cost ($)	(11) Gain from Off System Sales ($)
1	Jan - 2021	Off System	OS	448,880	448,880	1.944	3.532	8,726,029	15,853,435	5,678,698
2		St Lucie Reliability Sales		54,189	54,189	0.498	0.498	270,064	270,064	
3	**Total January Estimated**			503,069	503,069	1.788	3.205	8,996,093	16,123,499	5,678,698
4										
5	Feb - 2021	Off System	OS	418,320	418,320	2.002	3.339	8,374,792	13,969,457	4,229,427
6		St Lucie Reliability Sales		48,945	48,945	0.498	0.498	243,929	243,929	
7	**Total February Estimated**			467,265	467,265	1.845	3.042	8,618,720	14,213,386	4,229,427
8										
9	Mar - 2021	Off System	OS	245,520	245,520	2.012	3.090	4,940,966	7,587,552	1,921,037
10		St Lucie Reliability Sales		54,189	54,189	0.498	0.498	270,064	270,064	
11	**Total March Estimated**			299,709	299,709	1.739	2.622	5,211,030	7,857,616	1,921,037
12										
13	Apr - 2021	Off System	OS	191,400	191,400	1.966	3.074	3,763,476	5,883,251	1,641,275
14		St Lucie Reliability Sales		15,386	15,386	0.510	0.510	78,400	78,400	
15	**Total April Estimated**			206,786	206,786	1.858	2.883	3,841,876	5,961,651	1,641,275
16										
17	May - 2021	Off System	OS	205,530	205,530	1.969	3.131	4,046,461	6,435,234	1,926,331
18		St Lucie Reliability Sales		30,772	30,772	0.495	0.495	152,346	152,346	
19	**Total May Estimated**			236,302	236,302	1.777	2.788	4,198,807	6,587,581	1,926,331
20										
21	Jun - 2021	Off System	OS	138,600	138,600	2.119	3.305	2,936,676	4,580,937	1,401,711
22		St Lucie Reliability Sales		51,287	51,287	0.495	0.495	253,910	253,910	
23	**Total June Estimated**			189,887	189,887	1.680	2.546	3,190,586	4,834,847	1,401,711
24										
25	YTD-Jun	Off System		1,648,250	1,648,250	1.989	3.295	32,788,399	54,309,868	16,798,479
26		St Lucie Reliability Sales		254,770	254,770	0.498	0.498	1,268,713	1,268,713	
27	**Total 6 Month Period**			1,903,020	1,903,020	1.790	2.921	34,057,112	55,578,581	16,798,479
28										

ESTIMATED FOR THE PERIOD OF: JANUARY 2021 THROUGH DECEMBER 2021

(1) Line No.	(2) Month	(3) Sold To	(4) Type & Schedule	(5) Total KWH Sold (000)	(6) KWH from Own Generation (000)	(7) Fuel Cost (cents/KWH)	(8) Total Cost (cents/KWH)	(9) Total $ for Fuel Adj	(10) Total Cost ($)	(11) Gain from Off System Sales ($)
1	Jul - 2021	Off System	OS	138,880	138,880	2.225	3.417	3,090,034	4,746,107	1,413,034
2		St Lucie Reliability Sales		52,997	52,997	0.495	0.495	262,374	262,374	
3	**Total July Estimated**			191,877	191,877	1.747	2.610	3,352,407	5,008,481	1,413,034
4										
5	Aug - 2021	Off System	OS	142,600	142,600	2.089	3.239	2,978,610	4,618,484	1,319,024
6		St Lucie Reliability Sales		52,997	52,997	0.495	0.495	262,374	262,374	
7	**Total August Estimated**			195,597	195,597	1.657	2.495	3,240,984	4,880,858	1,319,024
8										
9	Sep - 2021	Off System	OS	123,000	123,000	2.222	3.489	2,733,069	4,290,929	1,250,360
10		St Lucie Reliability Sales		51,287	51,287	0.495	0.495	253,910	253,910	
11	**Total September Estimated**			174,287	174,287	1.714	2.608	2,986,979	4,544,840	1,250,360
12										
13	Oct - 2021	Off System	OS	108,810	108,810	2.350	3.595	2,556,951	3,911,981	1,055,802
14		St Lucie Reliability Sales		52,997	52,997	0.495	0.495	262,374	262,374	
15	**Total October Estimated**			161,807	161,807	1.742	2.580	2,819,325	4,174,354	1,055,802
16										
17	Nov - 2021	Off System	OS	191,100	191,100	1.832	2.867	3,501,420	5,479,676	1,452,731
18		St Lucie Reliability Sales		52,441	52,441	0.484	0.484	253,927	253,927	
19	**Total November Estimated**			243,541	243,541	1.542	2.354	3,755,347	5,733,604	1,452,731
20										
21	Dec - 2021	Off System	OS	245,830	245,830	1.894	2.960	4,655,512	7,277,441	1,982,771
22		St Lucie Reliability Sales		54,189	54,189	0.484	0.484	262,392	262,392	
23	**Total December Estimated**			300,019	300,019	1.639	2.513	4,917,904	7,539,832	1,982,771
24										
25	YTD	Off System		2,598,470	2,598,470	2.013	3.257	52,303,995	84,634,486	25,272,200
26		St Lucie Reliability Sales		571,679	571,679	0.494	0.494	2,826,064	2,826,064	
27	**Total 12 Month Period**			3,170,149	3,170,149	1.739	2.759	55,130,059	87,460,550	25,272,200
28										

Note: Totals may not add due to rounding.

ESTIMATED FOR THE PERIOD OF: JANUARY 2021 THROUGH DECEMBER 2021

(1)	(2)	(3)	(4)	(5)	(6)	(7)
Line No.	RAD - Fuel Projection E7 Schedule	Type & Schedule	KWH Purchased (000)	KWH for Firm	Fuel Cost (cents/KWH)	Total $ for Fuel Adj
1	**Jan - 2021**					
2	St Lucie Reliability		54,568	54,568	0.445	242,898
3	SWA		82,636	82,636	3.005	2,483,000
4	**Subtotal Jan - 2021**		137,204	137,204	1.987	2,725,898
5						
6	**Feb - 2021**					
7	St Lucie Reliability		49,287	49,287	0.445	219,392
8	SWA		81,292	81,292	3.026	2,459,994
9	**Subtotal Feb - 2021**		130,579	130,579	2.052	2,679,386
10						
11	**Mar - 2021**					
12	St Lucie Reliability		54,568	54,568	0.445	242,898
13	SWA		83,261	83,261	2.985	2,485,336
14	**Subtotal Mar - 2021**		137,829	137,829	1.979	2,728,234
15						
16	**Apr - 2021**					
17	St Lucie Reliability		51,600	51,600	0.456	235,038
18	SWA		75,442	75,442	2.973	2,243,229
19	**Subtotal Apr - 2021**		127,041	127,041	1.951	2,478,267
20						
21	**May - 2021**					
22	St Lucie Reliability		53,320	53,320	0.456	242,873
23	SWA		71,759	71,759	2.868	2,058,212
24	**Subtotal May - 2021**		125,078	125,078	1.840	2,301,085
25						
26	**Jun - 2021**					
27	St Lucie Reliability		51,600	51,600	0.456	235,038
28	SWA		83,066	83,066	3.058	2,540,062
29	**Subtotal Jun - 2021**		134,666	134,666	2.061	2,775,100
30						
31	**YTD-Jun - 2021**					
32	St Lucie Reliability		314,941	314,941	0.450	1,418,136
33	SWA		477,456	477,456	2.989	14,269,832
34	**Subtotal YTD-Jun - 2021**		792,397	792,397	1.980	15,687,968
35						

ESTIMATED FOR THE PERIOD OF: JANUARY 2021 THROUGH DECEMBER 2021

(1)	(2)	(3)	(4)	(5)	(6)	(7)
Line No.	RAD - Fuel Projection E7 Schedule	Type & Schedule	KWH Purchased (000)	KWH for Firm	Fuel Cost (cents/KWH)	Total $ for Fuel Adj
1	**Jul - 2021**					
2	St Lucie Reliability		53,320	53,320	0.456	242,873
3	SWA		75,070	75,070	3.047	2,287,742
4	**Subtotal Jul - 2021**		128,389	128,389	1.971	2,530,615
5						
6	**Aug - 2021**					
7	St Lucie Reliability		46,444	46,444	0.456	211,556
8	SWA		65,271	65,271	3.065	2,000,739
9	**Subtotal Aug - 2021**		111,715	111,715	1.980	2,212,294
10						
11	**Sep - 2021**					
12	SWA		73,937	73,937	3.119	2,305,782
13	**Subtotal Sep - 2021**		73,937	73,937	3.119	2,305,782
14						
15	**Oct - 2021**					
16	St Lucie Reliability		51,605	51,605	0.491	253,428
17	SWA		63,642	63,642	2.947	1,875,395
18	**Subtotal Oct - 2021**		115,247	115,247	1.847	2,128,823
19						
20	**Nov - 2021**					
21	St Lucie Reliability		52,808	52,808	0.480	253,429
22	SWA		72,490	72,490	3.170	2,297,664
23	**Subtotal Nov - 2021**		125,297	125,297	2.036	2,551,092
24						
25	**Dec - 2021**					
26	St Lucie Reliability		54,568	54,568	0.480	261,877
27	SWA		76,163	76,163	2.930	2,231,524
28	**Subtotal Dec - 2021**		130,731	130,731	1.907	2,493,401
29						
30	**2021**					
31	St Lucie Reliability		573,685	573,685	0.460	2,641,298
32	SWA		904,028	904,028	3.016	27,268,678
33	**Subtotal 2021**		1,477,713	1,477,713	2.024	29,909,976
34						
35	Note: Totals may not add due to rounding.					

ESTIMATED FOR THE PERIOD OF: JANUARY 2021 THROUGH DECEMBER 2021

(1)	(2)	(3)	(4)	(5)	(6)	(7)
Line No.	RAD - Fuel Projection E8 Schedule	Type & Schedule	Total KWH Purchased (000)	KWH for Firm (000)	Fuel Cost (cents/KWH)	Total $ for Fuel Adj
1	**Jan - 2021**					
2	Qualifying Facilities		26,970	26,970	1.925	519,164
3	**Subtotal Jan - 2021**		26,970	26,970	1.925	519,164
4						
5	**Feb - 2021**					
6	Qualifying Facilities		22,357	22,357	1.978	442,266
7	**Subtotal Feb - 2021**		22,357	22,357	1.978	442,266
8						
9	**Mar - 2021**					
10	Qualifying Facilities		27,134	27,134	1.936	525,407
11	**Subtotal Mar - 2021**		27,134	27,134	1.936	525,407
12						
13	**Apr - 2021**					
14	Qualifying Facilities		25,567	25,567	1.856	474,586
15	**Subtotal Apr - 2021**		25,567	25,567	1.856	474,586
16						
17	**May - 2021**					
18	Qualifying Facilities		28,212	28,212	1.789	504,676
19	**Subtotal May - 2021**		28,212	28,212	1.789	504,676
20						
21	**Jun - 2021**					
22	Qualifying Facilities		22,918	22,918	1.845	422,762
23	**Subtotal Jun - 2021**		22,918	22,918	1.845	422,762
24						
25	**YTD-Jun - 2021**					
26	Qualifying Facilities		153,158	153,158	1.886	2,888,861
27	**Subtotal YTD-Jun - 2021**		153,158	153,158	1.886	2,888,861

ESTIMATED FOR THE PERIOD OF: JANUARY 2021 THROUGH DECEMBER 2021

(1)	(2)	(3)	(4)	(5)	(6)	(7)
Line No.	RAD - Fuel Projection E8 Schedule	Type & Schedule	Total KWH Purchased (000)	KWH for Firm (000)	Fuel Cost (cents/KWH)	Total $ for Fuel Adj
28						
29	**Jul - 2021**					
30	Qualifying Facilities		24,589	24,589	1.947	478,873
31	**Subtotal Jul - 2021**		24,589	24,589	1.947	478,873
32						
33	**Aug - 2021**					
34	Qualifying Facilities		21,122	21,122	2.040	430,892
35	**Subtotal Aug - 2021**		21,122	21,122	2.040	430,892
36						
37	**Sep - 2021**					
38	Qualifying Facilities		28,318	28,318	1.947	551,230
39	**Subtotal Sep - 2021**		28,318	28,318	1.947	551,230
40						
41	**Oct - 2021**					
42	Qualifying Facilities		27,193	27,193	1.915	520,724
43	**Subtotal Oct - 2021**		27,193	27,193	1.915	520,724
44						
45	**Nov - 2021**					
46	Qualifying Facilities		27,266	27,266	1.811	493,763
47	**Subtotal Nov - 2021**		27,266	27,266	1.811	493,763
48						
49	**Dec - 2021**					
50	Qualifying Facilities		30,668	30,668	1.811	555,509
51	**Subtotal Dec - 2021**		30,668	30,668	1.811	555,509
52						
53	**2021**					
54	Qualifying Facilities		312,315	312,315	1.895	5,919,852
55	**Subtotal 2021**		312,315	312,315	1.895	5,919,852
56						
57						
58	Note: Totals may not add due to rounding.					

ESTIMATED FOR THE PERIOD OF: JANUARY 2021 THROUGH DECEMBER 2021

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Line No.		Purchased From	Type & Schedule	Total KWH Purchase (000)	Transaction Cost (cents/KWH)	Total $ for Fuel Adj	Cost if Generated (cents/KWH)	Cost if Generated Col (5) * Col (6)	Fuel Savings ($)
1	**Jan - 2021**	Economy	OS	0					
2		Subtotal Jan - 2021		0					
3									
4	**Feb - 2021**	Economy	OS	0					
5		Subtotal Feb - 2021		0					
6									
7	**Mar - 2021**	Economy	OS	20,460	2.400	491,040	2.896	592,463	101,423
8		Subtotal Mar - 2021		20,460	2.400	491,040	2.896	592,463	101,423
9									
10	**Apr - 2021**	Economy	OS	19,800	2.400	475,200	2.759	546,288	71,088
11		Subtotal Apr - 2021		19,800	2.400	475,200	2.759	546,288	71,088
12									
13	**May - 2021**	Economy	OS	37,200	2.450	911,400	2.715	1,009,930	98,530
14		Subtotal May - 2021		37,200	2.450	911,400	2.715	1,009,930	98,530
15									
16	**Jun - 2021**	Economy	OS	91,500	2.650	2,424,750	3.083	2,821,287	396,537
17		Subtotal Jun - 2021		91,500	2.650	2,424,750	3.083	2,821,287	396,537
18									
19		**YTD - Jun**							
20		**Economy**		168,960	2.546	4,302,390	2.942	4,969,968	667,578
21		**Sub-Total YTD - Jun**		168,960	2.546	4,302,390	2.942	4,969,968	667,578
22									

ESTIMATED FOR THE PERIOD OF: JANUARY 2021 THROUGH DECEMBER 2021

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Line No.		Purchased From	Type & Schedule	Total KWH Purchase (000)	Transaction Cost (cents/KWH)	Total $ for Fuel Adj	Cost if Generated (cents/KWH)	Cost if Generated Col (5) * Col (6)	Fuel Savings ($)
1	**Jul - 2021**	Economy	OS	44,020	2.700	1,188,540	3.084	1,357,388	168,848
2		Subtotal Jul - 2021		44,020	2.700	1,188,540	3.084	1,357,388	168,848
3									
4	**Aug - 2021**	Economy	OS	29,450	2.700	795,150	3.035	893,687	98,537
5		Subtotal Aug - 2021		29,450	2.700	795,150	3.035	893,687	98,537
6									
7	**Sep - 2021**	Economy	OS	72,000	2.650	1,908,000	3.136	2,258,031	350,031
8		Subtotal Sep - 2021		72,000	2.650	1,908,000	3.136	2,258,031	350,031
9									
10	**Oct - 2021**	Economy	OS	29,450	2.600	765,700	3.230	951,096	185,396
11		Subtotal Oct - 2021		29,450	2.600	765,700	3.230	951,096	185,396
12									
13	**Nov - 2021**	Economy	OS	3,300	1.800	59,400	2.694	88,911	29,511
14		Subtotal Nov - 2021		3,300	1.800	59,400	2.694	88,911	29,511
15									
16	**Dec - 2021**	Economy	OS	0					
17		Subtotal Dec - 2021		0					
18									
19		**YTD - Dec**		347,180	2.598	9,019,180	3.030	10,519,080	1,499,900
20		**Sub-Total YTD - Dec**		347,180	2.598	9,019,180	3.030	10,519,080	1,499,900
21									
22		Note: Totals may not add due to rounding.							

COMPANY: FLORIDA POWER & LIGHT COMPANY **SCHEDULE E10**

	CURRENT SEP 2020	PROPOSED JAN 2021 - DEC 2021	DIFFERENCE $	DIFFERENCE %
BASE	$69.94	$69.90	($0.04)	-0.06%
FUEL COST RECOVERY	$18.84	$21.23	$2.39	12.69%
ENERGY CONSERVATION COST RECOVERY	$1.39	$1.49	$0.10	7.19%
CAPACITY COST RECOVERY	$2.30	$2.04	-$0.26	-11.30%
ENVIRONMENTAL COST RECOVERY	$1.55	$1.49	-$0.06	-3.87%
STORM PROTECTION PLAN COST RECOVERY	$0.00	$0.42	$0.42	N/A
STORM RESTORATION SURCHARGE	$0.00	$0.00	$0.00	N/A
SUBTOTAL	$94.02	$96.57	$2.55	2.71%
GROSS RECEIPTS TAX	$2.41	$2.48	$0.07	2.90%
TOTAL	**$96.43**	**$99.05**	$2.62	2.72%

Line No.	H1 Schedule	2018	2019	2020	2021	% Diff 2019 to 2018	% Diff 2020 to 2019	% Diff 2020 to 2021
1	**Fuel Cost of System Net Generation ($)**							
2	Heavy Oil	33,336,536	13,793,931	13,866,418	4,984,674	(58.6%)	0.5%	(64.1%)
3	Light Oil	17,471,205	20,107,057	14,804,568	1,512,821	15.1%	(26.4%)	(89.8%)
4	Coal	70,954,592	74,236,959	50,709,323	62,980,302	4.6%	(31.7%)	24.2%
5	Gas	2,938,221,234	2,600,448,500	2,169,620,295	2,538,443,871	(11.5%)	(16.6%)	17.0%
6	Nuclear	175,457,637	159,950,571	147,687,701	147,077,238	(8.8%)	(7.7%)	(0.4%)
7	**Subtotal Fuel Cost of System Net Generation ($)**	3,235,441,204	2,868,537,019	2,396,688,304	2,754,998,906	(11.3%)	(16.4%)	15.0%
8								
9	**System Net Generation (MWh)**							
10	Heavy Oil	247,838	105,846	115,705	40,231	(57.3%)	9.3%	(65.2%)
11	Light Oil	128,769	223,502	97,367	7,393	73.6%	(56.4%)	(92.4%)
12	Coal	2,583,232	2,488,197	1,677,228	2,174,478	(3.7%)	(32.6%)	29.6%
13	Gas	91,213,460	93,401,386	91,592,476	87,164,479	2.4%	(1.9%)	(4.8%)
14	Nuclear	28,176,271	27,791,207	28,713,467	28,165,152	(1.4%)	3.3%	(1.9%)
15	Solar	1,835,949	2,368,307	4,080,010	6,493,025	29.0%	72.3%	59.1%
16	**Subtotal System Net Generation (MWh)**	124,185,520	126,378,446	126,276,252	124,044,758	1.8%	(0.1%)	(1.8%)
17								
18	**Units of Fuel Burned (Unit)**							
19	Heavy Oil	445,526	188,991	198,959	72,709	(57.6%)	5.3%	(63.5%)
20	Light Oil	188,693	203,957	180,477	18,788	8.1%	(11.5%)	(89.6%)
21	Coal	1,717,337	1,691,077	1,103,222	1,461,064	(1.5%)	(34.8%)	32.4%
22	Gas	646,603,153	651,359,136	633,079,793	598,793,557	0.7%	(2.8%)	(5.4%)
23	Nuclear	308,786,317	303,397,508	307,086,334	296,846,059	(1.7%)	1.2%	(3.3%)
24								
25								
26	**BTU Burned (MMBTU)**							
27	Heavy Oil	2,817,296	1,196,123	1,271,430	465,338	(57.5%)	6.3%	(63.4%)
28	Light Oil	1,091,030	1,182,072	1,053,796	109,534	8.3%	(10.9%)	(89.6%)
29	Coal	28,818,876	28,631,872	19,137,147	24,838,092	(0.6%)	(33.2%)	29.8%
30	Gas	660,577,429	665,984,354	640,798,422	598,793,557	0.8%	(3.8%)	(6.6%)
31	Nuclear	308,786,317	303,397,508	307,086,334	296,846,059	(1.7%)	1.2%	(3.3%)
32	**Subtotal BTU Burned (MMBTU)**	1,002,090,947	1,000,391,930	969,347,129	921,052,580	(0.2%)	(3.1%)	(5.0%)
33								
34	**Generation Mix (%)**							
35	Heavy Oil	0.20%	0.08%	0.09%	0.03%			
36	Light Oil	0.10%	0.18%	0.08%	0.01%			
37	Coal	2.08%	1.97%	1.33%	1.75%			
38	Gas	73.45%	73.91%	72.53%	70.27%			
39	Nuclear	22.69%	21.99%	22.74%	22.71%			
40	Solar	1.48%	1.87%	3.23%	5.23%			
41	**Subtotal Generation Mix (%)**	100.00%	100.00%	100.00%	100.00%			
42								
43	**Fuel Cost per Unit ($/Unit)**							
44	Heavy Oil	74.8252	72.9873	69.6948	68.5564	(2.5%)	(4.5%)	(1.6%)
45	Light Oil	92.5907	98.5848	82.0304	80.5206	6.5%	(16.8%)	(1.8%)
46	Coal	41.3166	43.8992	45.9647	43.1058	6.3%	4.7%	(6.2%)
47	Gas	4.5441	3.9923	3.4271	4.2393	(12.1%)	(14.2%)	23.7%
48	Nuclear	0.5682	0.5272	0.4809	0.4955	(7.2%)	(8.8%)	3.0%
49								
50	**Fuel Cost per MMBTU ($/MMBTU)**							
51	Heavy Oil	11.8328	11.5322	10.9062	10.7119	(2.5%)	(5.4%)	(1.8%)
52	Light Oil	16.0135	17.0100	14.0488	13.8114	6.2%	(17.4%)	(1.7%)
53	Coal	2.4621	2.5928	2.6498	2.5356	5.3%	2.2%	(4.3%)
54	Gas	4.4480	3.9047	3.3858	4.2393	(12.2%)	(13.3%)	25.2%
55	Nuclear	0.5682	0.5272	0.4809	0.4955	(7.2%)	(8.8%)	3.0%
56	**Subtotal Fuel Cost per MMBTU ($/MMBTU)**	3.2287	2.8674	2.4725	2.9911	(11.2%)	(13.8%)	21.0%
57								
58	**BTU Burned per KWH (BTU/KWH)**							
59	Heavy Oil	11,367	11,301	10,989	11,567	(0.6%)	(2.8%)	5.3%
60	Light Oil	8,473	5,289	10,823	14,816	(37.6%)	104.6%	36.9%
61	Coal	11,156	11,507	11,410	11,423	3.1%	(0.8%)	0.1%
62	Gas	7,242	7,130	6,996	6,870	(1.5%)	(1.9%)	(1.8%)
63	Nuclear	10,959	10,917	10,695	10,539	(0.4%)	(2.0%)	(1.5%)
64	**Subtotal BTU Burned per KWH (BTU/KWH)**	8,069	7,916	7,676	7,425	(1.9%)	(3.0%)	(3.3%)
65								
66	**Generated Fuel Cost per KWH (cents/KWH)**							
67	Heavy Oil	13.4509	13.0320	11.9843	12.3903	(3.1%)	(8.0%)	3.4%
68	Light Oil	13.5678	8.9964	15.2050	20.4629	(33.7%)	69.0%	34.6%
69	Coal	2.7467	2.9836	3.0234	2.8963	8.6%	1.3%	(4.2%)
70	Gas	3.2213	2.7842	2.3688	2.9122	(13.6%)	(14.9%)	22.9%
71	Nuclear	0.6227	0.5755	0.5143	0.5222	(7.6%)	(10.6%)	1.5%
72	**Subtotal Generated Fuel Cost per KWH (cents/KWH)**	2.6053	2.2698	1.8980	2.2210	(12.9%)	(16.4%)	17.0%

(Continued from Sheet No. 10.100)

ESTIMATED AS-AVAILABLE AVOIDED ENERGY COST

FPL will provide its most recent non-binding estimate of future AS-Available avoided cost projections within thirty days of a written request. In addition, As-Available Energy cost payments will include .0139¢/kWh for variable operation and maintenance expenses.

DELIVERY VOLTAGE ADJUSTMENT

The Company's actual hourly As-Available Energy costs shall be adjusted according to the delivery voltage by the following multipliers:

Delivery Voltage	Adjustment Factor
Transmission Voltage Delivery	1.0000
Primary Voltage Delivery	1.0111
Secondary Voltage Delivery	1.0295

PROJECTED ANNUAL GENERATION MIX AND FUEL PRICES

FPL's projected annual generation mix may be found on Schedules 5, 6.1 and 6.2 in FPL's Ten Year Site Plan.

(Continued on Sheet No. 10.102)

(Continued from Sheet No. 10.102)

B. Interconnection Charge for Non-Variable Utility Expenses:

The Qualifying Facility shall bear the cost required for interconnection, including the metering. The Qualifying Facility shall have the option of (i) payment in full for the interconnection costs upon completion of the interconnection facilities (including the time value of money during the construction) and providing a surety bond, letter of credit or comparable assurance of payment acceptable to the Company adequate to cover the interconnection costs, (ii) payment of monthly invoices from the Company for actual costs progressively incurred by the Company in installing the interconnection facilities, or (iii) upon a showing of credit worthiness, making equal monthly installment payments over a period no longer than thirty-six (36) months toward the full cost of interconnection. In the latter case, the Company shall assess interest at the rate then prevailing for the thirty (30) days highest grade commercial paper rate, such rate to be specified by the Company thirty (30) days prior to the date of each installment payment by the Qualifying Facility.

C. Interconnection Charge for Variable Utility Expenses:

The Qualifying Facility shall be billed monthly for the cost of variable utility expenses associated with the operation and maintenance of the interconnection facilities. These include (a) the Company's inspections of the interconnection facilities and (b) maintenance of any equipment beyond that which would be required to provide normal electric service to the Qualifying Facility if no sales to the Company were involved.

In lieu of payments for actual charges, the Qualifying Facility may pay a monthly charge equal to a percentage of the installed cost of the interconnection facilities necessary for the sale of energy to the Company. The applicable percentages are as follows:

Equipment Type	Charge
Metering Equipment	0.075%
Distribution Equipment	0.227%
Transmission Equipment	0.130%

D. Taxes and Assessments

The Qualifying Facility shall be billed monthly an amount equal to any taxes, assessments or other impositions, for which the Company is liable as a result of its purchases of As-Available Energy produced by the Qualifying Facility. In the event the Company receives a tax benefit as a result of its purchases of As-Available Energy produced by the Qualifying Facility, the Qualifying Facility shall be entitled to a refund in an amount equal to such benefit.

TERMS OF SERVICE

(1) It shall be the Qualifying Facility's responsibility to inform the Company of any change in the Qualifying Facility's electric generation capability.

(Continue on Sheet No. 10.104)

APPENDIX III
CAPACITY COST RECOVERY

JANUARY 2021 THROUGH DECEMBER 2021 FACTORS

RBD-7
DOCKET NO. 20200001-EI
FPL WITNESS: RENAE B. DEATON
EXHIBIT ___________
PAGES 1-38
SEPTEMBER 3, 2020

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20200001-EI EXHIBIT: 16
PARTY: FLORIDA POWER & LIGHT COMPANY – DIRECT
DESCRIPTION: R.B.Deaton RBD-7

APPENDIX III
CAPACITY COST RECOVERY
2021 FACTORS – JAN 2021 THROUGH DEC 2021
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ESTIMATED FOR THE PERIOD: JANUARY 2021 THROUGH DECEMBER 2021

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
Line No.	Strata	Line	Jan - 2021	Feb - 2021	Mar - 2021	Apr - 2021	May - 2021	Jun - 2021	Jul - 2021	Aug - 2021	Sep - 2021	Oct - 2021	Nov - 2021	Dec - 2021	2021
1	Base	Payments to Non-cogenerators	$1,317,600	$1,317,600	$1,317,600	$1,317,600	$1,317,600	$1,364,000	$1,364,000	$1,364,000	$1,364,000	$1,364,000	$1,364,000	$1,364,000	$16,136,000
2		Payments to Co-generators	$122,325	$122,325	$122,325	$122,325	$122,325	$122,325	$122,325	$122,325	$122,325	$122,325	$122,325	$122,325	$1,467,900
3		Cedar Bay Transaction - Regulatory Asset - Amortization and Return	$9,042,943	$9,011,846	$8,980,750	$8,949,653	$8,918,556	$8,887,459	$8,856,363	$8,825,266	$8,794,169	$8,763,072	$8,731,976	$8,700,879	$106,462,931
4		Cedar Bay Transaction - Regulatory Liability - Amortization and Return	($80,214)	($79,807)	($79,400)	($78,993)	($78,585)	($78,178)	($77,771)	($77,363)	($76,956)	($76,549)	($76,142)	($75,734)	($935,692)
5		Indiantown Transaction - Regulatory Asset - Amortization and Return	$5,844,977	$5,817,004	$5,789,030	$5,761,057	$5,733,083	$5,705,110	$5,677,136	$5,649,163	$5,621,189	$5,593,216	$5,565,242	$5,537,269	$68,293,477
6		SJRPP Transaction Revenue Requirements	$724,058	$712,348	$700,639	$688,930	$677,221	$665,512	$653,803	$642,093	$630,384	$618,675	$606,966	$595,257	$7,915,886
7		Incremental Plant Security Costs O&M	$2,699,150	$2,576,090	$2,893,700	$2,731,710	$2,449,771	$2,699,585	$2,805,691	$2,388,002	$2,371,496	$2,805,100	$2,493,762	$2,008,087	$30,922,144
8		Incremental Plant Security Costs Capital	$410,115	$410,489	$411,455	$412,589	$413,722	$414,855	$415,989	$417,122	$418,255	$419,389	$420,522	$425,835	$4,990,337
9		Incremental Nuclear NRC Compliance Costs O&M	$95,845	$95,320	$217,256	$96,715	$96,175	$96,715	$96,715	$96,715	$96,715	$96,175	$96,715	$99,252	$1,280,315
10		Incremental Nuclear NRC Compliance Costs Capital	$1,111,559	$1,108,678	$1,105,796	$1,102,915	$1,100,034	$1,098,582	$1,097,120	$1,094,220	$1,091,319	$1,088,651	$1,077,928	$1,061,613	$13,138,414
11		Transmission of Electricity by Others	($128,544)	($58,635)	($38,246)	($26,048)	($4,157)	($2,811)	($15,432)	($1,960)	($21,349)	($23,809)	($31,214)	($23,376)	($375,581)
12		Transmission Revenues from Capacity Sales	($1,448,709)	($1,365,239)	($725,549)	($478,500)	($462,443)	($242,550)	($243,040)	($320,850)	($307,500)	($299,228)	($525,525)	($639,158)	($7,058,290)
13		Subtotal Base	$19,711,104	$19,668,019	$20,695,356	$20,599,953	$20,283,303	$20,730,604	$20,752,899	$20,198,733	$20,104,049	$20,471,018	$19,846,556	$19,176,248	$242,237,843
14															
15	General	Incremental Plant Security Costs Capital	$217	$87	$768	$2,129	$3,491	$4,853	$6,214	$7,576	$8,938	$10,299	$11,661	$25,095	$81,328
16		Subtotal General	$217	$87	$768	$2,129	$3,491	$4,853	$6,214	$7,576	$8,938	$10,299	$11,661	$25,095	$81,328
17															
18	Intermediate	Incremental Plant Security Costs O&M	$312,308	$379,116	$574,504	$385,260	$419,704	$490,124	$405,693	$322,590	$366,271	$319,579	$323,453	$460,729	$4,759,332
19		Incremental Plant Security Costs Capital	$54,616	$54,494	$54,373	$54,251	$54,130	$54,008	$53,887	$53,765	$53,644	$53,522	$53,401	$53,279	$647,369
20		Subtotal Intermediate	$366,924	$433,611	$628,876	$439,511	$473,834	$544,132	$459,580	$376,355	$419,915	$373,101	$376,854	$514,008	$5,406,701
21															
22	Peaking	Incremental Plant Security Costs O&M	$37,184	$36,496	$113,633	$38,049	$37,432	$38,064	$38,068	$38,100	$38,091	$37,357	$37,967	$38,572	$529,013
23		Incremental Plant Security Costs Capital	$6,209	$6,189	$6,170	$6,150	$6,130	$6,111	$6,091	$6,072	$6,052	$6,032	$6,013	$5,993	$73,212
24		Subtotal Peaking	$43,393	$42,686	$119,803	$44,199	$43,563	$44,174	$44,159	$44,172	$44,143	$43,389	$43,980	$44,565	$602,225
25															
26	Solar	Incremental Plant Security Costs O&M	$10,000	$10,000	$10,000	$10,000	$10,000	$10,000	$10,000	$10,000	$10,000	$10,000	$10,000	$10,000	$120,000
27		Incremental Plant Security Costs Capital	$7,303	$7,271	$7,239	$7,207	$7,175	$7,143	$7,112	$7,080	$7,048	$7,016	$6,984	$6,952	$85,530
28		Subtotal Solar	$17,303	$17,271	$17,239	$17,207	$17,175	$17,143	$17,112	$17,080	$17,048	$17,016	$16,984	$16,952	$205,530
29															
30		Total	$20,138,941	$20,161,673	$21,462,042	$21,102,999	$20,821,366	$21,340,907	$21,279,964	$20,643,916	$20,594,092	$20,914,823	$20,296,034	$19,776,868	$248,533,626
31															
32		Totals may not add due to rounding													

ESTIMATED FOR THE PERIOD: JANUARY 2021 THROUGH DECEMBER 2021

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
Line No.	Line	Jan - 2021	Feb - 2021	Mar - 2021	Apr - 2021	May - 2021	Jun - 2021	Jul - 2021	Aug - 2021	Sep - 2021	Oct - 2021	Nov - 2021	Dec - 2021	2021
1	Total Capacity Costs	20,138,941	20,161,673	21,462,042	21,102,999	20,821,366	21,340,907	21,279,964	20,643,916	20,594,092	20,914,823	20,296,034	19,776,868	248,533,626
2														
3	Total Base Capacity Costs	19,711,104	19,668,019	20,695,356	20,599,953	20,283,303	20,730,604	20,752,899	20,198,733	20,104,049	20,471,018	19,846,556	19,176,248	242,237,843
4	Base Jurisdictional Factor	95.68908%	95.68908%	95.68908%	95.68908%	95.68908%	95.68908%	95.68908%	95.68908%	95.68908%	95.68908%	95.68908%	95.68908%	
5	Total Base Jurisdictionalized Capacity Costs	18,861,374	18,820,146	19,803,195	19,711,905	19,408,905	19,836,924	19,858,258	19,327,982	19,237,379	19,588,529	18,990,986	18,349,575	231,795,159
6														
7	Total Intermediate Capacity Costs	366,924	433,611	628,876	439,511	473,834	544,132	459,580	376,355	419,915	373,101	376,854	514,008	5,406,701
8	Intermediate Jurisdictional Factor	95.00813%	95.00813%	95.00813%	95.00813%	95.00813%	95.00813%	95.00813%	95.00813%	95.00813%	95.00813%	95.00813%	95.00813%	
9	Total Intermediate Jurisdictionalized Capacity Costs	348,608	411,965	597,484	417,572	450,181	516,970	436,638	357,568	398,953	354,476	358,041	488,350	5,136,805
10														
11	Total Peaking Capacity Costs	43,393	42,686	119,803	44,199	43,563	44,174	44,159	44,172	44,143	43,389	43,980	44,565	602,225
12	Peaking Jurisdictional Factor	95.27777%	95.27777%	95.27777%	95.27777%	95.27777%	95.27777%	95.27777%	95.27777%	95.27777%	95.27777%	95.27777%	95.27777%	
13	Total Peaking Jurisdictionalized Capacity Costs	41,343	40,670	114,145	42,111	41,506	42,088	42,074	42,086	42,059	41,340	41,903	42,460	573,786
14														
15	Total Solar Capacity Costs	17,303	17,271	17,239	17,207	17,175	17,143	17,112	17,080	17,048	17,016	16,984	16,952	205,530
16	Solar Jurisdictional Factor	95.68908%	95.68908%	95.68908%	95.68908%	95.68908%	95.68908%	95.68908%	95.68908%	95.68908%	95.68908%	95.68908%	95.68908%	
17	Total Solar Jurisdictionalized Capacity Costs	16,557	16,527	16,496	16,465	16,435	16,404	16,374	16,343	16,313	16,282	16,252	16,221	196,670
18														
19	Total General Capacity Costs	217	87	768	2,129	3,491	4,853	6,214	7,576	8,938	10,299	11,661	25,095	81,328
20	General Jurisdictional Factor	96.98877%	96.98877%	96.98877%	96.98877%	96.98877%	96.98877%	96.98877%	96.98877%	96.98877%	96.98877%	96.98877%	96.98877%	
21	Total General Jurisdictionalized Capacity Costs	210	84	744	2,065	3,386	4,706	6,027	7,348	8,669	9,989	11,310	24,340	78,879
22														
23	Jurisdictionalized Capacity Costs	19,268,093	19,289,392	20,532,065	20,190,119	19,920,413	20,417,093	20,359,371	19,751,327	19,703,372	20,010,616	19,418,493	18,920,946	237,781,299
24														
25														
26														
27	FINAL TRUE-UP -- (Over)/Under Recovery													($5,141,967)
28	ACT/EST TRUE-UP -- (Over)/Under Recovery													($7,388,454)
29	2018 SoBRA True-up													($12,401,882)
30	Total (Lines 23 + 27 + 28 + 29)													212,848,995
31	Revenue Tax Multiplier													1.00072
32	Total Recoverable Capacity Costs													213,002,247
33														
34														
35	Totals may not add due to rounding													

ESTIMATED FOR THE PERIOD: JANUARY 2021 THROUGH DECEMBER 2021

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
Line No.	Rate Class Summary - Non-Fuel	AVG 12CP Load Factor at Meter (%) [1]	Projected Sales at Meter (kwh) [2]	Projected AVG 12CP at Meter (kW) [3]	Demand Loss Expansion Factor [4]	Energy Loss Expansion Factor [5]	Projected Sales at Generation (kwh) [6]	Projected AVG 12CP at Generation (kW) [7]	Percentage of Sales at Generation (%) [8]	Percentage of Demand at Generation (%) [9]
1	RS1/RTR1	61.756%	59,729,073,564	11,040,784	1.06227433	1.04681581	62,525,338,592	11,728,341	53.46670%	57.14078%
2	GS1/GST1	61.000%	6,506,168,667	1,217,559	1.06227433	1.04681581	6,810,760,231	1,293,382	5.82402%	6.30139%
3	GSD1/GSDT1/HLFT1/GSD1-EV	70.568%	27,339,372,990	4,422,592	1.06219494	1.04675521	28,617,631,124	4,697,655	24.47152%	22.88709%
4	OS2	154.701%	9,166,365	676	1.03727996	1.02815396	9,424,434	702	0.00806%	0.00342%
5	GSLD1/GSLDT1/CS1/CST1/HLFT2/GSLD1-EV	69.605%	10,202,110,568	1,673,190	1.06138651	1.04617543	10,673,197,409	1,775,902	9.12687%	8.65224%
6	GSLD2/GSLDT2/CS2/CST2/HLFT3	84.453%	2,700,592,177	365,038	1.05234833	1.03941858	2,807,045,699	384,147	2.40036%	1.87157%
7	GSLD3/GSLDT3/CS3/CST3	83.597%	259,242,549	35,401	1.02222729	1.01685659	263,612,494	36,188	0.22542%	0.17631%
8	SST1T	84.075%	92,787,905	12,598	1.02222729	1.01685659	94,351,993	12,879	0.08068%	0.06274%
9	SST1D1/SST1D2/SST1D3	52.653%	1,849,941	401	1.04514716	1.03665634	1,917,753	419	0.00164%	0.00204%
10	CILC D/CILC G	85.444%	2,739,981,680	366,067	1.05216077	1.03935565	2,847,815,431	385,161	2.43523%	1.87651%
11	CILC T	93.078%	1,470,591,289	180,360	1.02222729	1.01685659	1,495,380,442	184,369	1.27873%	0.89825%
12	MET	76.794%	80,325,996	11,941	1.03727996	1.02815396	82,587,491	12,386	0.07062%	0.06034%
13	OL1/SL1/SL1M/PL1	13,844.128%	575,951,839	475	1.06227433	1.04681581	602,915,492	504	0.51557%	0.00246%
14	SL2/SL2M/GSCU1	96.257%	105,664,172	12,531	1.06227433	1.04681581	110,610,926	13,312	0.09459%	0.06485%
15										
16	Total		111,812,879,702	19,339,613			116,942,589,509	20,525,345	100.00000%	100.00000%

17
18 [1] Calculated: Col(4)/8760 hours / Col(5)
19 [2] Projected kwh sales for the period January 2021 through December 2021.
20 [3] AVG 12 CP load factor based on 2017-2019 load research data and 2021 projections.
21 [4] Based on 2021 demand losses.
22 [5] Based on 2021 energy losses.
23 [6] Col(4) * Col(7)
24 [7] Col(5) * Col(6)
25 [8] Col(8) / Total for Col(8)
26 [9] Col(9) / Total for Col(9)
27
28 Note: There are currently no customers taking service on Schedules ISST1(D) and ISST1(T). Should any customer begin taking service on these schedules during the period, they will be billed using the applicable SST1 factor.
29
30 Totals may not add due to rounding.

ESTIMATED FOR THE PERIOD: JANUARY 2021 THROUGH DECEMBER 2021

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.	RATE SCHEDULE	Percentage of Sales at Generation (%) [1]	Percentage of Demand at Generation (%) [2]	Energy Related Cost ($) [3]	Demand Related Cost ($) [4]	Total Capacity Costs ($) [5]	Projected Sales at Meter (kwh) [6]	Billing KW Load Factor (%) [7]	Projected Billed KW at Meter (KW) [8]	Capacity Recovery Factor ($/KW) [9]	Capacity Recovery Factor ($/kwh) [10]	RDC ($/KW) [11]	SDD ($/KW) [12]
1	RS1/RTR1	53.46670%	57.14078%	8,760,405	112,348,741	121,109,146	59,729,073,564			-	0.00203	-	-
2	GS1/GST1	5.82402%	6.30139%	954,253	12,389,628	13,343,881	6,506,168,667			-	0.00205	-	-
3	GSD1/GSDT1/HLFT1/GSD1-EV	24.47152%	22.88709%	4,009,607	45,000,020	49,009,627	27,339,372,990	51.93294%	72,114,537	0.68	-	-	-
4	OS2	0.00806%	0.00342%	1,320	6,721	8,041	9,166,365			-	0.00088	-	-
5	GSLD1/GSLDT1/CS1/CST1/HLFT2/GSLD1-EV	9.12687%	8.65224%	1,495,418	17,011,810	18,507,228	10,202,110,568	57.38509%	24,353,877	0.76	-	-	-
6	GSLD2/GSLDT2/CS2/CST2/HLFT3	2.40036%	1.87157%	393,294	3,679,841	4,073,136	2,700,592,177	66.01952%	5,603,557	0.73	-	-	-
7	GSLD3/GSLDT3/CS3/CST3	0.22542%	0.17631%	36,935	346,650	383,584	259,242,549	68.80148%	516,162	0.74	-	-	-
8	SST1T	0.08068%	0.06274%	13,220	123,367	136,586	92,787,905	14.79189%	859,300	-	-	0.09	0.04
9	SST1D1/SST1D2/SST1D3	0.00164%	0.00204%	269	4,016	4,284	1,849,941	11.92716%	21,247	-	-	0.09	0.04
10	CILC D/CILC G	2.43523%	1.87651%	399,006	3,689,553	4,088,559	2,739,981,680	71.04120%	5,283,413	0.77	-	-	-
11	CILC T	1.27873%	0.89825%	209,517	1,766,119	1,975,636	1,470,591,289	75.77028%	2,658,705	0.74	-	-	-
12	MET	0.07062%	0.06034%	11,571	118,646	130,218	80,325,996	55.87377%	196,936	0.66	-	-	-
13	OL1/SL1/SL1M/PL1	0.51557%	0.00246%	84,474	4,833	89,307	575,951,839			-	0.00016	-	-
14	SL2/SL2M/GSCU1	0.09459%	0.06485%	15,498	127,515	143,013	105,664,172			-	0.00135	-	-
15	TOTAL			16,384,788	196,617,459	213,002,247	111,812,879,702						

16

17 [1] Obtained from Page 3, Col(10)

18 [2] Obtained from Page 3, Col(11)

19 [3] (Total Capacity Costs/13) * Col(3)

20 [4] (Total Capacity Costs/13 * 12) * Col(4)

21 [5] Col(5) + Col(6)

22 [6] Projected kwh sales for the period January 2021 through December 2021.

23 [7] (kWh sales / 8760 hours)/(avg customer NCP)

24 [8] Col(8) / (Col(9) *730)

25 [9] Col(7) / Col(10)

26 [10] Col(7) / Col(8)

27 [11] RDC = Reservation Demand Charge - (Total Col 7)/(Page 3 Total Col 5)(.10)(Page x Col 5)/12 Months

28 [12] SDD = Sum of Daily Demand Charge - (Total Col 7)/(Page 3 Total Col 5)/(21 onpeak days)(Page 3 Col 6)/12 Months

29

30 Note: There are currently no customers taking service on Schedules ISST1(D) and ISST1(T). Should any customer begin taking service on these schedules during the period, they will be billed using the applicable SST1 factor.

31

32 Totals may not add due to rounding.

ESTIMATED FOR THE PERIOD: JANUARY 2021 THROUGH DECEMBER 2021

Line No.	Strata	Line	Beginning of Period	Jan - 2021	Feb - 2021	Mar - 2021	Apr - 2021	May - 2021	Jun - 2021	Jul - 2021	Aug - 2021	Sep - 2021	Oct - 2021	Nov - 2021	Dec - 2021	Total
1	**Base**															
2		**INVESTMENTS**														
3		Expenditures/Additions		$133,332	$260,332	$310,332	$310,332	$310,332	$310,332	$310,332	$310,332	$310,332	$310,332	$310,332	($3,186,649)	$0
4		Clearings to Plant		($188,117)	-	-	-	-	-	-	-	-	-	-	$3,497,000	$3,308,883
5		Retirements		($188,117)	-	-	-	-	-	-	-	-	-	-	-	($188,117)
6		Other		-	-	-	-	-	-	-	-	-	-	-	-	-
7																
8		Plant-In-Service/Depreciation Base	$44,029,637	$43,841,520	$43,841,520	$43,841,520	$43,841,520	$43,841,520	$43,841,520	$43,841,520	$43,841,520	$43,841,520	$43,841,520	$43,841,520	$47,338,520	
9		Less: Accumulated Depreciation	$3,801,246	$3,754,088	$3,895,048	$4,036,007	$4,176,967	$4,317,926	$4,458,886	$4,599,845	$4,740,805	$4,881,764	$5,022,724	$5,163,683	$5,308,837	
10		CWIP - Non Interest Bearing	$0	$133,332	$393,663	$703,995	$1,014,327	$1,324,659	$1,634,990	$1,945,322	$2,255,654	$2,565,985	$2,876,317	$3,186,649	$0	
11																
12		Net Investment (Lines 8 - 9 + 10)	$40,228,391	$40,220,764	$40,340,136	$40,509,508	$40,678,880	$40,848,252	$41,017,625	$41,186,997	$41,356,369	$41,525,741	$41,695,114	$41,864,486	$42,029,683	
13																
14		Average Net Investment		$40,224,577	$40,280,450	$40,424,822	$40,594,194	$40,763,566	$40,932,939	$41,102,311	$41,271,683	$41,441,055	$41,610,427	$41,779,800	$41,947,085	
15																
16		Return on Average Net Investment														
17		a. Equity Component grossed up for taxes [(1)]		$227,572	$227,888	$228,705	$229,663	$230,621	$231,579	$232,538	$233,496	$234,454	$235,412	$236,370	$237,317	$2,785,614
18		b. Debt Component (Line 14 x debt rate x 1/12) [(2)]		$41,584	$41,642	$41,791	$41,966	$42,141	$42,316	$42,492	$42,667	$42,842	$43,017	$43,192	$43,365	$509,015
19																
20		Investment Expenses														
21		a. Depreciation		$140,959	$140,959	$140,959	$140,959	$140,959	$140,959	$140,959	$140,959	$140,959	$140,959	$140,959	$145,154	$1,695,708
22		b. Amortization		-	-	-	-	-	-	-	-	-	-	-	-	-
23		c. Other		-	-	-	-	-	-	-	-	-	-	-	-	-
24																
25		Total System Recoverable Expenses (Lines 17 + 18 + 21)		$410,115	$410,489	$411,455	$412,589	$413,722	$414,855	$415,989	$417,122	$418,255	$419,389	$420,522	$425,835	$4,990,337
26																
27																
28																
29																
30	[(1)] The Gross-up factor for taxes is 0.7547818, which reflects the Federal Income Tax Rate of 21%. The monthly Equity Component for the Jan. – Dec. 2021 period is 5.1242% based on the 2021 Forecasted Earnings Surveillance Report and reflects a 10.55% return on equity.															
31	[(2)] The Debt Component for the Jan. – Dec. 2021 period is 1.2406% based on the 2021 Forecasted Earnings Surveillance Report.															
32																
33		Totals may not add due to rounding														

ESTIMATED FOR THE PERIOD: JANUARY 2021 THROUGH DECEMBER 2021

Line No.	Strata	Line	Beginning of Period	Jan - 2021	Feb - 2021	Mar - 2021	Apr - 2021	May - 2021	Jun - 2021	Jul - 2021	Aug - 2021	Sep - 2021	Oct - 2021	Nov - 2021	Dec - 2021	Total
1	**Intermediate**															
2		**INVESTMENTS**														
3		Expenditures/Additions		-	-	-	-	-	-	-	-	-	-	-	-	-
4		Clearings to Plant		-	-	-	-	-	-	-	-	-	-	-	-	-
5		Retirements		-	-	-	-	-	-	-	-	-	-	-	-	-
6		Other		-	-	-	-	-	-	-	-	-	-	-	-	-
7																
8		Plant-In-Service/Depreciation Base	$6,410,357	$6,410,357	$6,410,357	$6,410,357	$6,410,357	$6,410,357	$6,410,357	$6,410,357	$6,410,357	$6,410,357	$6,410,357	$6,410,357	$6,410,357	
9		Less: Accumulated Depreciation	$953,517	$971,680	$989,843	$1,008,006	$1,026,169	$1,044,332	$1,062,495	$1,080,658	$1,098,821	$1,116,985	$1,135,148	$1,153,311	$1,171,474	
10		CWIP - Non Interest Bearing	-	-	-	-	-	-	-	-	-	-	-	-	-	
11																
12		Net Investment (Lines 8 - 9 + 10)	$5,456,841	$5,438,677	$5,420,514	$5,402,351	$5,384,188	$5,366,025	$5,347,862	$5,329,699	$5,311,536	$5,293,373	$5,275,209	$5,257,046	$5,238,883	
13																
14		Average Net Investment		$5,447,759	$5,429,596	$5,411,433	$5,393,270	$5,375,107	$5,356,943	$5,338,780	$5,320,617	$5,302,454	$5,284,291	$5,266,128	$5,247,965	
15																
16		Return on Average Net Investment														
17		a. Equity Component grossed up for taxes (1)		$30,821	$30,718	$30,615	$30,513	$30,410	$30,307	$30,204	$30,102	$29,999	$29,896	$29,793	$29,691	$363,068
18		b. Debt Component (Line 14 x debt rate x 1/12) (2)		$5,632	$5,613	$5,594	$5,576	$5,557	$5,538	$5,519	$5,500	$5,482	$5,463	$5,444	$5,425	$66,343
19																
20		Investment Expenses														
21		a. Depreciation		$18,163	$18,163	$18,163	$18,163	$18,163	$18,163	$18,163	$18,163	$18,163	$18,163	$18,163	$18,163	$217,957
22		b. Amortization		-	-	-	-	-	-	-	-	-	-	-	-	-
23		c. Other		-	-	-	-	-	-	-	-	-	-	-	-	-
24																
25		Total System Recoverable Expenses (Lines 17 + 18 + 21)		$54,616	$54,494	$54,373	$54,251	$54,130	$54,008	$53,887	$53,765	$53,644	$53,522	$53,401	$53,279	$647,369
26																
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29																

30 (1) The Gross-up factor for taxes is 0.7547818, which reflects the Federal Income Tax Rate of 21%. The monthly Equity Component for the Jan. – Dec. 2021 period is 5.1242% based on the 2021 Forecasted Earnings Surveillance Report and reflects a 10.55% return on equity.

31 (2) The Debt Component for the Jan. – Dec. 2021 period is 1.2406% based on the 2021 Forecasted Earnings Surveillance Report.

32

33 Totals may not add due to rounding

ESTIMATED FOR THE PERIOD: JANUARY 2021 THROUGH DECEMBER 2021

Line No.	Strata	Line	Beginning of Period	Jan - 2021	Feb - 2021	Mar - 2021	Apr - 2021	May - 2021	Jun - 2021	Jul - 2021	Aug - 2021	Sep - 2021	Oct - 2021	Nov - 2021	Dec - 2021	Total
1	**General**															
2		**INVESTMENTS**														
3		Expenditures/Additions		-	-	$203,500	$203,500	$203,500	$203,500	$203,500	$203,500	$203,500	$203,500	$203,500	($1,831,500)	-
4		Clearings to Plant		($132,325)	-	-	-	-	-	-	-	-	-	-	$2,035,000	$1,902,675
5		Retirements		($132,325)	-	-	-	-	-	-	-	-	-	-	-	($132,325)
6		Other		-	-	-	-	-	-	-	-	-	-	-	-	-
7																
8		Plant-In-Service/Depreciation Base	$145,284	$12,959	$12,959	$12,959	$12,959	$12,959	$12,959	$12,959	$12,959	$12,959	$12,959	$12,959	$2,047,959	
9		Less: Accumulated Depreciation	$132,195	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$12,113	
10		CWIP - Non Interest Bearing	-	-	-	$203,500	$407,000	$610,500	$814,000	$1,017,500	$1,221,000	$1,424,500	$1,628,000	$1,831,500	-	
11																
12		Net Investment (Lines 8 - 9 + 10)	$13,089	$12,959	$12,959	$216,459	$419,959	$623,459	$826,959	$1,030,459	$1,233,959	$1,437,459	$1,640,959	$1,844,459	$2,035,846	
13																
14		Average Net Investment		$13,024	$12,959	$114,709	$318,209	$521,709	$725,209	$928,709	$1,132,209	$1,335,709	$1,539,209	$1,742,709	$1,940,152	
15																
16		Return on Average Net Investment														
17		a. Equity Component grossed up for taxes (b)		$74	$73	$649	$1,800	$2,952	$4,103	$5,254	$6,406	$7,557	$8,708	$9,859	$10,976	$58,411
18		b. Debt Component (Line 14 x debt rate x 1/12) (c)		$13	$13	$119	$329	$539	$750	$960	$1,170	$1,381	$1,591	$1,802	$2,006	$10,673
19																
20		Investment Expenses														
21		a. Depreciation		$130	-	-	-	-	-	-	-	-	-	-	$12,113	$12,243
22		b. Amortization		-	-	-	-	-	-	-	-	-	-	-	-	-
23		c. Other		-	-	-	-	-	-	-	-	-	-	-	-	-
24																
25		Total System Recoverable Expenses (Lines 17 + 18 + 21)		$217	$87	$768	$2,129	$3,491	$4,853	$6,214	$7,576	$8,938	$10,299	$11,661	$25,095	$81,328
26																
27																
28																
29																

30 (b) The Gross-up factor for taxes is 0.746550, which reflects the Federal Income Tax Rate of 21%. The monthly Equity Component for the Jan. – Dec. 2020 period is 5.0206% based on the May 2019 ROR Surveillance Report and reflects a 10.55% return on equity.

31 (c) The Debt Component for the Jan. – Dec. 2020 period is 1.3507% based on the May 2019 Earnings Surveillance Report.

32

33 Totals may not add due to rounding

ESTIMATED FOR THE PERIOD: JANUARY 2021 THROUGH DECEMBER 2021

Line No.	Strata	Line	Beginning of Period	Jan - 2021	Feb - 2021	Mar - 2021	Apr - 2021	May - 2021	Jun - 2021	Jul - 2021	Aug - 2021	Sep - 2021	Oct - 2021	Nov - 2021	Dec - 2021	Total
1	**Peaking**															
2		**INVESTMENTS**														
3		Expenditures/Additions		-	-	-	-	-	-	-	-	-	-	-	-	-
4		Clearings to Plant		-	-	-	-	-	-	-	-	-	-	-	-	-
5		Retirements		-	-	-	-	-	-	-	-	-	-	-	-	-
6		Other		-	-	-	-	-	-	-	-	-	-	-	-	-
7																
8		Plant-In-Service/Depreciation Base	$672,783	$672,783	$672,783	$672,783	$672,783	$672,783	$672,783	$672,783	$672,783	$672,783	$672,783	$672,783	$672,783	
9		Less: Accumulated Depreciation	$181,191	$184,120	$187,049	$189,979	$192,908	$195,837	$198,766	$201,695	$204,624	$207,554	$210,483	$213,412	$216,341	
10		CWIP - Non Interest Bearing	-	-	-	-	-	-	-	-	-	-	-	-	-	
11																
12		Net Investment (Lines 8 - 9 + 10)	$491,592	$488,663	$485,734	$482,804	$479,875	$476,946	$474,017	$471,088	$468,159	$465,229	$462,300	$459,371	$456,442	
13																
14		Average Net Investment		$490,127	$487,198	$484,269	$481,340	$478,411	$475,481	$472,552	$469,623	$466,694	$463,765	$460,836	$457,906	
15																
16		Return on Average Net Investment														
17		a. Equity Component grossed up for taxes (1)		$2,773	$2,756	$2,740	$2,723	$2,707	$2,690	$2,673	$2,657	$2,640	$2,624	$2,607	$2,591	$32,181
18		b. Debt Component (Line 14 x debt rate x 1/12) (2)		$507	$504	$501	$498	$495	$492	$489	$485	$482	$479	$476	$473	$5,880
19																
20		Investment Expenses														
21		a. Depreciation		$2,929	$2,929	$2,929	$2,929	$2,929	$2,929	$2,929	$2,929	$2,929	$2,929	$2,929	$2,929	$35,150
22		b. Amortization		-	-	-	-	-	-	-	-	-	-	-	-	-
23		c. Other		-	-	-	-	-	-	-	-	-	-	-	-	-
24																
25		Total System Recoverable Expenses (Lines 17 + 18 + 21)		$6,209	$6,189	$6,170	$6,150	$6,130	$6,111	$6,091	$6,072	$6,052	$6,032	$6,013	$5,993	$73,212
26																
27																
28																
29																

30 (1) The Gross-up factor for taxes is 0.7547818, which reflects the Federal Income Tax Rate of 21%. The monthly Equity Component for the Jan. – Dec. 2021 period is 5.1242% based on the 2021 Forecasted Earnings Surveillance Report and reflects a 10.55% return on equity.

31 (2) The Debt Component for the Jan. – Dec. 2021 period is 1.2406% based on the 2021 Forecasted Earnings Surveillance Report.

32

33 Totals may not add due to rounding

ESTIMATED FOR THE PERIOD: JANUARY 2021 THROUGH DECEMBER 2021

Line No.	Strata	Line	Beginning of Period	Jan - 2021	Feb - 2021	Mar - 2021	Apr - 2021	May - 2021	Jun - 2021	Jul - 2021	Aug - 2021	Sep - 2021	Oct - 2021	Nov - 2021	Dec - 2021	Total
1	**Solar**															
2		**INVESTMENTS**														
3		Expenditures/Additions		-	-	-	-	-	-	-	-	-	-	-	-	-
4		Clearings to Plant		-	-	-	-	-	-	-	-	-	-	-	-	-
5		Retirements		-	-	-	-	-	-	-	-	-	-	-	-	-
6		Other		-	-	-	-	-	-	-	-	-	-	-	-	-
7																
8		Plant-In-Service/Depreciation Base	$400,685	$400,685	$400,685	$400,685	$400,685	$400,685	$400,685	$400,685	$400,685	$400,685	$400,685	$400,685	$400,685	
9		Less: Accumulated Depreciation	$19,756	$24,526	$29,296	$34,066	$38,836	$43,606	$48,376	$53,146	$57,916	$62,687	$67,457	$72,227	$76,997	
10		CWIP - Non Interest Bearing	-	-	-	-	-	-	-	-	-	-	-	-	-	
11																
12		Net Investment (Lines 8 - 9 + 10)	$380,929	$376,159	$371,389	$366,619	$361,848	$357,078	$352,308	$347,538	$342,768	$337,998	$333,228	$328,458	$323,688	
13																
14		Average Net Investment		$378,544	$373,774	$369,004	$364,233	$359,463	$354,693	$349,923	$345,153	$340,383	$335,613	$330,843	$326,073	$4,227,700
15																
16		Return on Average Net Investment														
17		a. Equity Component grossed up for taxes [1]		$2,142	$2,115	$2,088	$2,061	$2,034	$2,007	$1,980	$1,953	$1,926	$1,899	$1,872	$1,845	$23,918
18		b. Debt Component (Line 14 x debt rate x 1/12) [2]		$391	$386	$381	$377	$372	$367	$362	$357	$352	$347	$342	$337	$4,371
19																
20		Investment Expenses														
21		a. Depreciation		$4,770	$4,770	$4,770	$4,770	$4,770	$4,770	$4,770	$4,770	$4,770	$4,770	$4,770	$4,770	$57,241
22		b. Amortization		-	-	-	-	-	-	-	-	-	-	-	-	-
23		c. Other		-	-	-	-	-	-	-	-	-	-	-	-	-
24																
25		Total System Recoverable Expenses (Lines 17 + 18 + 21)		$7,303	$7,271	$7,239	$7,207	$7,175	$7,143	$7,112	$7,080	$7,048	$7,016	$6,984	$6,952	$85,530
26																
27																
28																
29																

30 [1] The Gross-up factor for taxes is 0.746550, which reflects the Federal Income Tax Rate of 21%. The monthly Equity Component for the Jan. – Dec. 2020 period is 5.0206% based on the May 2019 ROR Surveillance Report and reflects a 10.55% return on equity.

31 [2] The Debt Component for the Jan. – Dec. 2020 period is 1.3507% based on the May 2019 Earnings Surveillance Report.

32

33 Totals may not add due to rounding

ESTIMATED FOR THE PERIOD: JANUARY 2021 THROUGH DECEMBER 2021

Line No.	Strata	Line	Beginning of Period	Jan - 2021	Feb - 2021	Mar - 2021	Apr - 2021	May - 2021	Jun - 2021	Jul - 2021	Aug - 2021	Sep - 2021	Oct - 2021	Nov - 2021	Dec - 2021	Total
1	**Base**															
2		**INVESTMENTS**														
3		Expenditures/Additions		-	-	-	-	-	($767,588)	-	-	-	($130,784)	-	-	($898,372)
4		Clearings to Plant		-	-	-	-	-	$767,588	-	-	-	$130,784	($1,250,338)	($1,126,657)	($1,478,623)
5		Retirements		-	-	-	-	-	-	-	-	-	-	($1,250,338)	($1,126,657)	($2,376,995)
6		Other		-	-	-	-	-	-	-	-	-	-	-	-	-
7																
8		Plant-In-Service/Depreciation Base	$113,154,081	$113,154,081	$113,154,081	$113,154,081	$113,154,081	$113,154,081	$113,921,669	$113,921,669	$113,921,669	$113,921,669	$114,052,453	$112,802,115	$111,675,458	
9		Less: Accumulated Depreciation	$12,428,353	$12,858,967	$13,289,581	$13,720,195	$14,150,809	$14,581,423	$15,013,472	$15,446,955	$15,880,437	$16,313,920	$16,747,636	$15,923,167	$15,208,869	
10		CWIP - Non Interest Bearing	$1,254,852	$1,254,852	$1,254,852	$1,254,852	$1,254,852	$1,254,852	$487,263	$487,263	$487,263	$487,263	$356,480	$356,480	$356,480	
11																
12		Net Investment (Lines 8 - 9 + 10)	$101,980,580	$101,549,966	$101,119,352	$100,688,738	$100,258,124	$99,827,509	$99,395,461	$98,961,978	$98,528,495	$98,095,012	$97,661,296	$97,235,427	$96,823,069	
13																
14		Average Net Investment		$101,765,273	$101,334,659	$100,904,045	$100,473,431	$100,042,816	$99,611,485	$99,178,719	$98,745,237	$98,311,754	$97,878,154	$97,448,362	$97,029,248	
15																
16		Return on Average Net Investment														
17		a. Equity Component grossed up for taxes (1)		$575,740	$573,304	$570,868	$568,431	$565,995	$563,555	$561,106	$558,654	$556,202	$553,749	$551,317	$548,946	$6,747,866
18		b. Debt Component (Line 14 x debt rate x 1/12) (2)		$105,205	$104,760	$104,315	$103,869	$103,424	$102,978	$102,531	$102,083	$101,635	$101,186	$100,742	$100,309	$1,233,037
19																
20		Investment Expenses														
21		a. Depreciation		$430,614	$430,614	$430,614	$430,614	$430,614	$432,049	$433,483	$433,483	$433,483	$433,716	$425,869	$412,358	$5,157,511
22		b. Amortization		-	-	-	-	-	-	-	-	-	-	-	-	-
23		c. Other		-	-	-	-	-	-	-	-	-	-	-	-	-
24																
25		Total System Recoverable Expenses (Lines 17 + 18 + 21)		$1,111,559	$1,108,678	$1,105,796	$1,102,915	$1,100,034	$1,098,582	$1,097,120	$1,094,220	$1,091,319	$1,088,651	$1,077,928	$1,061,613	$13,138,414
26																
27																
28																
29																

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31 (2) The Debt Component for the Jan. – Dec. 2021 period is 1.2406% based on the 2021 Forecasted Earnings Surveillance Report.

32

33 Totals may not add due to rounding

ESTIMATED FOR THE PERIOD: JANUARY 2021 THROUGH DECEMBER 2021

Line No.	Line	Beginning of Period	Jan - 2021	Feb - 2021	Mar - 2021	Apr - 2021	May - 2021	Jun - 2021	Jul - 2021	Aug - 2021	Sep - 2021	Oct - 2021	Nov - 2021	Dec - 2021	Total
1															
2	Regulatory Asset Loss of PPA		$223,071,453	$218,424,131	$213,776,809	$209,129,487	$204,482,165	$199,834,843	$195,187,521	$190,540,199	$185,892,877	$181,245,555	$176,598,233	$171,950,911	
3															
4	Regulatory Asset - Loss of PPA Amort		$4,647,322	$4,647,322	$4,647,322	$4,647,322	$4,647,322	$4,647,322	$4,647,322	$4,647,322	$4,647,322	$4,647,322	$4,647,322	$4,647,322	$55,767,864
5															
6	Unamortized Regulatory Asset - Loss of PPA	$223,071,453	$218,424,131	$213,776,809	$209,129,487	$204,482,165	$199,834,843	$195,187,521	$190,540,199	$185,892,877	$181,245,555	$176,598,233	$171,950,911	$167,303,589	
7															
8	Average Unamortized Regulatory Asset - Loss of PPA		$220,747,792	$216,100,470	$211,453,148	$206,805,826	$202,158,504	$197,511,182	$192,863,860	$188,216,538	$183,569,216	$178,921,894	$174,274,572	$169,627,250	
9															
10	Regulatory Asset - Income Tax Gross Up		140,089,201	137,170,676	134,252,151	131,333,626	128,415,101	125,496,576	122,578,051	119,659,526	116,741,001	113,822,476	110,903,951	107,985,426	
11															
12	Regulatory Asset Amortization - Income Tax Gross-Up		2,918,525	2,918,525	2,918,525	2,918,525	2,918,525	2,918,525	2,918,525	2,918,525	2,918,525	2,918,525	2,918,525	2,918,525	35,022,300
13															
14	Unamortized Regulatory Asset - Income Tax Gross Up		137,170,676	134,252,151	131,333,626	128,415,101	125,496,576	122,578,051	119,659,526	116,741,001	113,822,476	110,903,951	107,985,426	105,066,901	
15															
16	Return on Unamortized Regulatory Asset - Loss of PPA only														
17	Equity Component		$942,637	$922,792	$902,947	$883,102	$863,257	$843,412	$823,567	$803,722	$783,877	$764,032	$744,187	$724,342	$10,001,877
18															
19	Equity Comp. grossed up for taxes (1)		$1,248,887	$1,222,595	$1,196,302	$1,170,010	$1,143,718	$1,117,425	$1,091,133	$1,064,841	$1,038,548	$1,012,256	$985,963	$959,671	$13,251,349
20															
21	Debt Component (Line 4 * debt rate / 12) (2)		$228,209	$223,405	$218,600	$213,796	$208,991	$204,187	$199,383	$194,578	$189,774	$184,969	$180,165	$175,361	$2,421,418
22															
23	Total Return Requirements (Line 19 + 21)		$1,477,096	$1,445,999	$1,414,903	$1,383,806	$1,352,709	$1,321,612	$1,290,516	$1,259,419	$1,228,322	$1,197,225	$1,166,129	$1,135,032	$15,672,767
24	Total Recoverable Costs (Line 4 + 12 + 23)		$9,042,943	$9,011,846	$8,980,750	$8,949,653	$8,918,556	$8,887,459	$8,856,363	$8,825,266	$8,794,169	$8,763,072	$8,731,976	$8,700,879	$106,462,931
25															
26															
27															

28 (1) The Gross-up factor for taxes is 0.746550, which reflects the Federal Income Tax Rate of 21%. The monthly Equity Component for the Jan. – Dec. 2020 period is 5.0206% based on the May 2019 ROR Surveillance Report and reflects a 10.55% return on equity.

29 (2) The Debt Component for the Jan. – Dec. 2020 period is 1.3507% based on the May 2019 Earnings Surveillance Report.

30

31 Totals may not add due to rounding

ESTIMATED FOR THE PERIOD: JANUARY 2021 THROUGH DECEMBER 2021

Line No.	Line	Beginning of Period	Jan - 2021	Feb - 2021	Mar - 2021	Apr - 2021	May - 2021	Jun - 2021	Jul - 2021	Aug - 2021	Sep - 2021	Oct - 2021	Nov - 2021	Dec - 2021	Total
1															
2	Regulatory Liability - Book/Tax Timing Difference		($2,921,701)	($2,860,833)	($2,799,965)	($2,739,097)	($2,678,229)	($2,617,361)	($2,556,493)	($2,495,625)	($2,434,757)	($2,373,889)	($2,313,021)	($2,252,153)	
3															
4	Regulatory Liability Amortization		$60,868	$60,868	$60,868	$60,868	$60,868	$60,868	$60,868	$60,868	$60,868	$60,868	$60,868	$60,868	$730,416
5															
6	Unamortized Regulatory Liability - Book/Tax Timing Diff	($2,921,701)	($2,860,833)	($2,799,965)	($2,739,097)	($2,678,229)	($2,617,361)	($2,556,493)	($2,495,625)	($2,434,757)	($2,373,889)	($2,313,021)	($2,252,153)	($2,191,285)	
7															
8	Average Unamortized Regulatory Liability - Book/Tax Timing Difference		($2,891,267)	($2,830,399)	($2,769,531)	($2,708,663)	($2,647,795)	($2,586,927)	($2,526,059)	($2,465,191)	($2,404,323)	($2,343,455)	($2,282,587)	($2,221,719)	
9															
10	Return on Unamortized Regulatory Asset - Loss of PPA only														
11	Equity Component		($12,346)	($12,086)	($11,826)	($11,567)	($11,307)	($11,047)	($10,787)	($10,527)	($10,267)	($10,007)	($9,747)	($9,487)	($131,001)
12															
13	Equity Comp. grossed up for taxes [1]		($16,357)	($16,013)	($15,669)	($15,324)	($14,980)	($14,636)	($14,291)	($13,947)	($13,603)	($13,258)	($12,914)	($12,569)	($173,561)
14															
15	Debt Component (Line 8 * debt rate / 12) [2]		($2,989)	($2,926)	($2,863)	($2,800)	($2,737)	($2,674)	($2,611)	($2,549)	($2,486)	($2,423)	($2,360)	($2,297)	($31,715)
16															
17	Total Return Requirements (Line 13 + 15)		($19,346)	($18,939)	($18,532)	($18,125)	($17,717)	($17,310)	($16,903)	($16,495)	($16,088)	($15,681)	($15,274)	($14,866)	($205,276)
18	Total Recoverable Costs (Line 4 + 17)		($80,214)	($79,807)	($79,400)	($78,993)	($78,585)	($78,178)	($77,771)	($77,363)	($76,956)	($76,549)	($76,142)	($75,734)	($935,692)
19															
20															
21															

22 [1] The Gross-up factor for taxes is 0.7547818, which reflects the Federal Income Tax Rate of 21%. The monthly Equity Component for the Jan. – Dec. 2021 period is 5.1242% based on the 2021 Forecasted Earnings Surveillance Report and reflects a 10.55% return on equity.

23 [2] The Debt Component for the Jan. – Dec. 2021 period is 1.2406% based on the 2021 Forecasted Earnings Surveillance Report.

24

25 Totals may not add due to rounding

ESTIMATED FOR THE PERIOD: JANUARY 2021 THROUGH DECEMBER 2021

Line No.	Line	Beginning of Period	Jan - 2021	Feb - 2021	Mar - 2021	Apr - 2021	May - 2021	Jun - 2021	Jul - 2021	Aug - 2021	Sep - 2021	Oct - 2021	Nov - 2021	Dec - 2021	Total
1															
2	Regulatory Asset Loss of PPA [3]		$250,833,333	$246,652,777	$242,472,221	$238,291,666	$234,111,110	$229,930,555	$225,749,999	$221,569,444	$217,388,888	$213,208,333	$209,027,777	$204,847,221	
3															
4	Regulatory Asset - Loss of PPA Amort		$4,180,556	$4,180,556	$4,180,556	$4,180,556	$4,180,556	$4,180,556	$4,180,556	$4,180,556	$4,180,556	$4,180,556	$4,180,556	$4,180,556	$50,166,667
5															
6	Unamortized Regulatory Asset - Loss of PPA	$250,833,333	$246,652,777	$242,472,221	$238,291,666	$234,111,110	$229,930,555	$225,749,999	$221,569,444	$217,388,888	$213,208,333	$209,027,777	$204,847,221	$200,666,666	
7															
8	Average Unamortized Regulatory Asset - Loss of PPA		$248,743,055	$244,562,499	$240,381,944	$236,201,388	$232,020,833	$227,840,277	$223,659,721	$219,479,166	$215,298,610	$211,118,055	$206,937,499	$202,756,944	
9															
10	Return on Unamortized Regulatory Asset - Loss of PPA only														
11	Equity Component		$1,062,183	$1,044,331	$1,026,479	$1,008,627	$990,775	$972,924	$955,072	$937,220	$919,368	$901,516	$883,665	$865,813	$11,567,972
12															
13	Equity Comp. grossed up for taxes [1]		$1,407,271	$1,383,619	$1,359,968	$1,336,316	$1,312,665	$1,289,013	$1,265,361	$1,241,710	$1,218,058	$1,194,407	$1,170,755	$1,147,103	$15,326,246
14															
15	Debt Component (Line 4 * debt rate / 12) [2]		$257,151	$252,829	$248,507	$244,185	$239,863	$235,541	$231,219	$226,898	$222,576	$218,254	$213,932	$209,610	$2,800,564
16															
17	Total Return Requirements (Line 13 + 15)		$1,664,422	$1,636,448	$1,608,475	$1,580,501	$1,552,528	$1,524,554	$1,496,581	$1,468,607	$1,440,634	$1,412,660	$1,384,687	$1,356,713	$18,126,810
18	Total Recoverable Costs (Line 4 + 17)		$5,844,977	$5,817,004	$5,789,030	$5,761,057	$5,733,083	$5,705,110	$5,677,136	$5,649,163	$5,621,189	$5,593,216	$5,565,242	$5,537,269	$68,293,477
19															
20															
21															

22 [1] The Gross-up factor for taxes is 0.7547818, which reflects the Federal Income Tax Rate of 21%. The monthly Equity Component for the Jan. – Dec. 2021 period is 5.1242% based on the 2021 Forecasted Earnings Surveillance Report and reflects a 10.55% return on equity.

23 [2] The Debt Component for the Jan. – Dec. 2021 period is 1.2406% based on the 2021 Forecasted Earnings Surveillance Report.

24 [3] Recovery of the Indiantown Transaction is based on the settlement agreement approved by the FPSC in Docket No. 160154-EI, Order No. PSC-16-0506-FOF-EI.

25

26 Totals may not add due to rounding

ESTIMATED FOR THE PERIOD: JANUARY 2021 THROUGH DECEMBER 2021

Line No.	Line	Beginning Balance	Jan - 2021	Feb - 2021	Mar - 2021	Apr - 2021	May - 2021	Jun - 2021	Jul - 2021	Aug - 2021	Sep - 2021	Oct - 2021	Nov - 2021	Dec - 2021	Total
1	Regulatory Asset - SJRPP Transaction Shutdown Payment [3]		$19,652,174	$17,686,957	$15,721,739	$13,756,522	$11,791,304	$9,826,087	$7,860,870	$5,895,652	$3,930,435	$1,965,217	$0	($1,965,217)	
2	Regulatory Asset - SJRPP Transaction Shutdown Payment Amortization		$1,965,217	$1,965,217	$1,965,217	$1,965,217	$1,965,217	$1,965,217	$1,965,217	$1,965,217	$1,965,217	$1,965,217	$1,965,217	$1,965,217	$23,582,609
3	Unamortized Regulatory Asset - SJRPP Transaction Shutdown Payment	$19,652,174	$17,686,957	$15,721,739	$13,756,522	$11,791,304	$9,826,087	$7,860,870	$5,895,652	$3,930,435	$1,965,217	$0	($1,965,217)	($3,930,435)	
4															
5	Other regulatory liability - SJRPP Suspension Liability		($2,153,173)	($1,937,856)	($1,722,538)	($1,507,221)	($1,291,904)	($1,076,586)	($861,269)	($645,952)	($430,635)	($215,317)		$215,317	
6	Other regulatory liability - SJRPP Suspension Liability Amortization (Refund)		($215,317)	($215,317)	($215,317)	($215,317)	($215,317)	($215,317)	($215,317)	($215,317)	($215,317)	($215,317)	($215,317)	($215,317)	($2,583,807)
7	Unamortized Regulatory Liability - SJRPP Suspension Liability	($2,153,173)	($1,937,856)	($1,722,538)	($1,507,221)	($1,291,904)	($1,076,586)	($861,269)	($645,952)	($430,635)	($215,317)		$215,317	$430,635	
8															
9	Average Net Unamortized Regulatory Asset/Liab (Lines 3 + 7)		$16,624,051	$14,874,151	$13,124,251	$11,374,351	$9,624,451	$7,874,551	$6,124,650	$4,374,750	$2,624,850	$874,950	($874,950)	($2,624,850)	
10															
11	Equity Component		$70,988	$63,516	$56,043	$48,571	$41,098	$33,626	$26,153	$18,681	$11,209	$3,736	($3,736)	($11,209)	$358,676
12	Equity Comp. grossed up for taxes [1]		$94,051	$84,151	$74,251	$64,351	$54,451	$44,550	$34,650	$24,750	$14,850	$4,950	($4,950)	($14,850)	$475,205
13	Debt Component (Line 9 x debt rate x 1/12) [2]		$17,186	$15,377	$13,568	$11,759	$9,950	$8,141	$6,332	$4,523	$2,714	$905	($905)	($2,714)	$86,834
14															
15	Total Return Requirements (Line 12 + 13)		$111,237	$99,528	$87,819	$76,110	$64,400	$52,691	$40,982	$29,273	$17,564	$5,855	($5,855)	($17,564)	$562,040
16															
17	Other SJRPP Transaction Items [4]														
18	SJRPP Deferred Interest Amortization (Refund)		($269,182)	($269,182)	($269,182)	($269,182)	($269,182)	($269,182)	($269,182)	($269,182)	($269,182)	($269,182)	($269,182)	($269,182)	($3,230,181)
19	SJRPP Article 8 PPA Dismantlement Accrual Amortization (Refund)		($867,898)	($867,898)	($867,898)	($867,898)	($867,898)	($867,898)	($867,898)	($867,898)	($867,898)	($867,898)	($867,898)	($867,898)	($10,414,774)
20															
21	Total Recoverable Expenses (Lines 2 + 6 + 12 + 13 + 18 + 19)		$724,058	$712,348	$700,639	$688,930	$677,221	$665,512	$653,803	$642,093	$630,384	$618,675	$606,966	$595,257	$7,915,886
22															

23 [1] The Gross-up factor for taxes is 0.7547818, which reflects the Federal Income Tax Rate of 21%. The monthly Equity Component for the Jan. – Dec. 2021 period is 5.1242% based on the 2021 Forecasted Earnings Surveillance Report and reflects a 10.55% return on equity.

24 [2] The Debt Component for the Jan. – Dec. 2021 period is 1.2406% based on the 2021 Forecasted Earnings Surveillance Report.

25 [3] Recovery of the SJRPP Transaction over a 46 month period is based on the settlement agreement approved by the FPSC in Docket No. 20170123-EI Order No. PSC-2017-0415-AS-EI.

26 [4] The total amount of SJRPP Deferred Interest and Article 8 PPA Dismantlement Accrual to refund is $12.4M and $39.9M, respectively. The unamortized balances for these regulatory liabilities are a reflected in rate base.

FLORIDA POWER & LIGHT COMPANY

Equity @ 10.55%

FORECASTED 2021
CAPITAL STRUCTURE AND COST RATES [a]

	ADJUSTED RETAIL	RATIO	MIDPOINT COST RATES	WEIGHTED COST	PRE-TAX WEIGHTED COST
LONG_TERM_DEBT	14,422,813,072	30.730%	3.86%	1.1856%	1.19%
SHORT_TERM_DEBT	699,416,366	1.490%	0.75%	0.0112%	0.01%
PREFERRED_STOCK	0	0.000%	0.00%	0.0000%	0.00%
CUSTOMER_DEPOSITS	417,807,033	0.890%	2.04%	0.0182%	0.02%
COMMON_EQUITY [b]	22,313,469,981	47.543%	10.55%	5.0158%	6.65%
DEFERRED_INCOME_TAX	8,285,651,758	17.654%	0.00%	0.0000%	0.00%
INVESTMENT_TAX_CREDITS					
ZERO COST	0	0.000%	0.00%	0.0000%	0.00%
WEIGHTED COST	794,379,656	1.693%	7.92%	0.1341%	0.17%
TOTAL	$46,933,537,866	100.00%		6.3648%	8.03%

CALCULATION OF THE WEIGHTED COST FOR CONVERTIBLE INVESTMENT TAX CREDITS (C-ITC) [c]

	ADJUSTED RETAIL	RATIO	COST RATE	WEIGHTED COST	PRE TAX COST
LONG TERM DEBT	$14,422,813,072	39.26%	3.858%	1.515%	1.515%
PREFERRED STOCK	0	0.00%	0.000%	0.000%	0.000%
COMMON EQUITY	22,313,469,981	60.74%	10.550%	6.408%	8.490%
TOTAL	$36,736,283,053	100.00%		7.923%	10.005%
RATIO					

DEBT COMPONENTS:

LONG TERM DEBT	1.1856%
SHORT TERM DEBT	0.0112%
CUSTOMER DEPOSITS	0.0182%
TAX CREDITS -WEIGHTED	0.0256%
TOTAL DEBT	**1.2406%**

EQUITY COMPONENTS:

PREFERRED STOCK	0.0000%
COMMON EQUITY	5.0158%
TAX CREDITS -WEIGHTED	0.1085%
TOTAL EQUITY	**5.1242%**
TOTAL	6.3648%
PRE-TAX EQUITY	6.7890%
PRE-TAX TOTAL	8.0296%

Note:

(a) Forecasted capital structure includes a deferred income tax proration adjustment consistent with FPSC Order No. PSC-2020-0165-PAA-EU, Docket No. 20200118-EU.
(b) Cost rate for common equity represents FPL's mid-point return on equity approved by the FPSC in Order No. PSC-16-0560-AS-EI, Docket Nos. 160021-EI, 160061-EI, 160062-EI, and 160088-EI.

(c) This capital structure applies only to Convertible Investment Tax Credit (C-ITC)

2021 Projection

Contract	Capacity MW	Term Start	Term End	Contract Type
Broward South - 1991 Agreement	3.5	1/1/1993	12/31/2026	QF

QF = Qualifying Facility

2021 Capacity in Dollars

	January	February	March	April	May	June	July	August	September	October	November	December	Year-to-date
BS-NEG '91	$122,325	$122,325	$122,325	$122,325	$122,325	$122,325	$122,325	$122,325	$122,325	$122,325	$122,325	$122,325	$1,467,900
Total	$122,325	$122,325	$122,325	$122,325	$122,325	$122,325	$122,325	$122,325	$122,325	$122,325	$122,325	$122,325	$1,467,900

Florida Power & Light Company
Schedule E12 - Capacity Costs

2021 Projection

Contract	Counterparty	Identification	Contract Start Date	Contract End Date
1	Solid Waste Authority (40MW)	Other Entity	January 1, 2012	April 1, 2032
2	Solid Waste Authority (70MW)	Other Entity	July 16, 2016	May 31, 2034

2021 Capacity in MW

Contract	January	February	March	April	May	June	July	August	September	October	November	December
1	40	40	40	40	40	40	40	40	40	40	40	40
2	70	70	70	70	70	70	70	70	70	70	70	70
Total	110	110	110	110	110	110	110	110	110	110	110	110

2021 Capacity in Dollars

Contract	January	February	March	April	May	June	July	August	September	October	November	December
1	1,317,600	1,317,600	1,317,600	1,317,600	1,317,600	1,364,000	1,364,000	1,364,000	1,364,000	1,364,000	1,364,000	1,364,000
2	249,533	249,533	249,533	249,533	249,533	249,533	249,533	249,533	249,533	249,533	249,533	249,533
Total	1,567,133	1,567,133	1,567,133	1,567,133	1,567,133	1,613,533	1,613,533	1,613,533	1,613,533	1,613,533	1,613,533	1,613,533

Total Capacity Payments to Non-Cogenerators for 2021 (1), (2)	16,136,000

(1) Total short-term capacity payments do not include payments for the Solid Waste Authority - 70 MW unit. Capacity costs for this unit were recovered through the Energy Conservation Cost Recovery Clause in 2014, consistent with Commission Order No. PSC-11-0293-FOF-EU issued in Docket No. 110018-EU on July 6, 2011.

(2) Appendix III, page 1, line 1

FLORIDA POWER & LIGHT COMPANY
CALCULATION OF CAPACITY RECOVERY FACTOR FOR INDIANTOWN
JANUARY 2021 THROUGH DECEMBER 2021
12CP & 1/13th COS Allocation Method

	Rate Schedule	(1) Projected Sales at Meter (kWh)	(2) Billing kW Load Factor (%)	(3) Projected Billed kW at Meter (kW)	(4) Total Capacity Costs ($)	(5) Capacity Recovery Factor ($/kW)	(6) Capacity Recovery Factor ($/kWh)
1	RS1/RTR1	59,729,073,564	-		$795,399		0.00001
2	GS1/GST1/WIES1	6,506,168,667	-		$76,043		0.00001
3	GSD1/GSDT1/HLFT1/GSD1-EV	27,339,372,990	51.93294%	72,114,537	$295,546	0.00	
4	OS2	9,166,365	-		$98		0.00001
5	GSLD1/GSLDT1/CS1/CST1/HLFT2/GSLD1-EV	10,202,110,568	57.38509%	24,353,877	$119,402	0.00	
6	GSLD2/GSLDT2/CS2/CST2/HLFT3	2,700,592,177	66.01952%	5,603,557	$23,804	0.00	
7	GSLD3/GSLDT3/CS3/CST3	259,242,549	68.80148%	516,162	$1,642	0.00	
8	SST1T	92,787,905	14.79189%	859,300	$682		
9	SST1D1/SST1D2/SST1D3	1,849,941	11.92716%	21,247	$123		
10	CILC D/CILC G	2,739,981,680	71.04120%	5,283,413	$26,488	0.01	
11	CILC T	1,470,591,289	75.77028%	2,658,705	$13,560	0.01	
12	MET	80,325,996	55.87377%	196,936	$1,025	0.01	
13	OL1/SL1/PL1/SL-1M	575,951,839	-		$1,316		0.00000
14	SL2, GSCU1, SL2M	105,664,172	-		$926		0.00001
		111,812,879,702		111,607,733	$1,356,055		

CAPACITY RECOVERY FACTORS FOR STANDBY RATES

Demand Charge (RDD) = (Total col 4)/(Doc 2, Total col 7)(.10) (Doc 2, col 4) / 12 months

Sum of Daily Demand Charge (DDC) = (Total col 4)/(Doc 2, Total col 7)/(21 onpeak days) (Doc 2, col 4) / 12 months

CAPACITY RECOVERY FACTORS

	RDD ** ($/kw)	DDC ** ($/kw)
ISST1D	$0.00	$0.00
ISST1T	$0.00	$0.00
SST1T	$0.00	$0.00
SST1D1/SST1D2/SST1D3	$0.00	$0.00

FLORIDA POWER & LIGHT COMPANY
BASED ON RATE CASE ALLOCATION OF INDIANTOWN REVENUE REQUIREMENT
JANUARY 2021 THROUGH DECEMBER 2021
12CP & 1/13th COS Allocation Method

	Rate (1)	12 CP & 1/13 Weighted Avg Demand (MW)[1] (2)	Allocation (3)	2021 Indiantown Revenue Requirement Allocation (4)
1	RS1/RTR1	11,510	58.7%	$795,399
2	GS1/GST1/WIES1	1,100	5.6%	$76,043
3	GSD1/GSDT1/HLFT1/GSD1-EV	4,277	21.8%	$295,546
4	OS2	1	0.0%	$98
5	GSLD1/GSLDT1/CS1/CST1/HLFT2/GSLD1-EV	1,728	8.8%	$119,402
6	GSLD2/GSLDT2/CS2/CST2/HLFT3	344	1.8%	$23,804
7	GSLD3/GSLDT3/CS3/CST3	24	0.1%	$1,642
8	SST1T	10	0.1%	$682
9	SST1D1/SST1D2/SST1D3	2	0.0%	$123
10	CILC D/CILC G	383	2.0%	$26,488
11	CILC T	196	1.0%	$13,560
12	MET	15	0.1%	$1,025
13	OL1/SL1/PL1/SL-1M	19	0.1%	$1,316
14	SL2, GSCU1, SL2M	13	0.1%	$926
15	Total	19,623	100.0%	$1,356,055

Notes:
[1] From MFR E-9 Column 11 "12 CP & 1/13 Weighted Avg Demand (MW)" for 2020

ESTIMATED FOR THE PERIOD: JANUARY 2021 THROUGH DECEMBER 2021

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
Line No.	Rate Schedule	Jan - Dec Capacity Recovery Factor				Indiantown Capacity Recovery Factor		Total Jan - Dec Capacity Recovery Factor			
		Capacity Recovery Factor ($/KW)	Capacity Recovery Factor ($/kwh)	RDC ($/KW)	SDD ($/KW)	Capacity Recovery Factor ($/KW)	Capacity Recovery Factor ($/kwh)	Capacity Recovery Factor ($/KW)	Capacity Recovery Factor ($/kwh)	RDC ($/KW)	SDD ($/KW)
1	RS1/RTR1	-	0.00203	-	-	-	0.00001	-	0.00204	-	-
2	GS1/GST1	-	0.00205	-	-	-	0.00001	-	0.00206	-	-
3	GSD1/GSDT1/HLFT1/GSD1-EV	0.68	-	-	-	-	-	0.68	-	-	-
4	OS2	-	0.00088	-	-	-	0.00001	-	0.00089	-	-
5	GSLD1/GSLDT1/CS1/CST1/HLFT2/GSLD1-EV	0.76	-	-	-	-	-	0.76	-	-	-
6	GSLD2/GSLDT2/CS2/CST2/HLFT3	0.73	-	-	-	-	-	0.73	-	-	-
7	GSLD3/GSLDT3/CS3/CST3	0.74	-	-	-	-	-	0.74	-	-	-
8	SST1T	-	-	0.09	0.04	-	-	-	-	0.09	0.04
9	SST1D1/SST1D2/SST1D3	-	-	0.09	0.04	-	-	-	-	0.09	0.04
10	CILC D/CILC G	0.77	-	-	-	0.01	-	0.78	-	-	-
11	CILC T	0.74	-	-	-	0.01	-	0.75	-	-	-
12	MET	0.66	-	-	-	0.01	-	0.67	-	-	-
13	OL1/SL1/SL1M/PL1	-	0.00016	-	-	-	-	-	0.00016	-	-
14	SL2/SL2M/GSCU1	-	0.00135	-	-	-	0.00001	-	0.00136	-	-

INDIANTOWN SUBSIDIARY
2021 REVENUE REQUIREMENTS

Line No.	Revenue Requirement Calculation	2021
1		
2		
3	Jurisdictional Adjusted Rate Base	$9,137,822
4		
5	Rate of Return on Rate Base	6.36%
6		
7	Required Jurisdictional Net Operating Income	581,603
8		
9	Jurisdictional Adjusted Net Operating Income (Loss)	(429,363)
10		
11	Net Operating Income Deficiency (Excess)	1,010,967
12		
13	Net Operating Income Multiplier [(1)]	1.34135
14		
15	Revenue Requirement	$1,356,055
16		
17		
18		
19		
20		
21		
22		
23	Notes:	
24	[(1)] Represents the 2018 NOI multiplier provided on Page 13 of Exhibit KO-20 in	
25	Docket No. 20160021-EI revised with new federal tax rates for the Tax Cuts and Jobs Act enacted in 2017 and effective in 2018.	

INDIANTOWN SUBSIDIARY
2021 REVENUE REQUIREMENTS

Line No.	Capital Structure [1]	Jurisdictional Adjusted	Ratio	Cost Rate	Wtd Cost Rate
1	Long Term Debt	$ 14,422,813,072	30.73%	3.86%	1.19%
2	Short Term Debt	699,416,366	1.49%	0.75%	0.01%
3	Preferred Stock	-	0.00%	0.00%	0.00%
4	Common Equity	22,313,469,981	47.54%	10.55%	5.02%
5	Customer Deposits	417,807,033	0.89%	2.04%	0.02%
6	Deferred Income Taxes	8,285,651,758	17.65%	0.00%	0.00%
7	Investment Tax Credits	794,379,656	1.69%	7.92%	0.13%
8	TOTAL	$ 46,933,537,866	100.00%		6.36%

Line No.	Rate Base - 13-Month Average	Per Book	Sep Factor [4]	Jurisdictional
13	Plant In Service[2]	$ 8,500,000	95.40%	$ 8,108,704
14	Working Capital[3]	1,058,277	97.24%	1,029,119
15	Total	$ 9,558,277		$ 9,137,822

Line No.	Net Operating Income	Per Book	Sep Factor[4]	Jurisdictional
21	Property Insurance [5]	5,000	96.52%	4,826
22	Property Taxes	590,000	96.66%	570,304
23	Income Taxes	(150,803)		(145,767)
24	Total NOI	$ (444,197)		$ (429,363)

31 Notes:

32 [1] Forecasted 2021 WACC from FPL's May 2020 MOPR. Forecasted capital structure includes a deferred income tax proration adjustment consistent with FPSC Order No. PSC-2020-0165-PAA-EU, Docket No. 20200118-EU.

33 [2] Represents land.

34 [3] Represents projected working capital for 2021.

35 [4] Based on FPL's most recent cost of service calculations prepared for the 2020 budget cycle.

36 [5] FPL is retaining most of the risk to insure the facility.

FPL - 2021 PROJECTED SEPARATION FACTORS

CLAUSES (Dec 2019 LF)

	SUMMARY
DEMAND	
E101 - Transmission	0.902300
E102 - Non-Stratified Production	0.956891
E103INT - Intermediate Strata Production	0.950081
E103PEAK - Peaking Strata Production	0.952778
E104 - Distribution	1.000000
ENERGY	
FPL201 - Total Sales	0.952084
FPL202 - Non-Stratified Sales	0.956788
FPL203INT - Intermediate Strata Sales	0.949979
FPL203PEAK - Peaking Strata Sales	0.952675
GENERAL PLANT	
I900 - LABOR	0.969888

RATE CLASS	12 CP - KW	VOLTAGE LEVEL % - DEMAND			LOSS EXPANSION FACTORS			12 CP @ GENERATION - KW				% OF TOTAL	
	@ METER	TRANS	PRIMARY	SECOND	TRANS	PRIMARY	SECOND	TRANS	PRIMARY	SECOND	TOTAL	SYSTEM	RETAIL
CILC-1D	351,746	0.0000	0.4203	0.5797	1.0222	1.0373	1.0623	0	153,357	216,599	369,956	1.6263%	1.8024%
CILC-1G	14,320	0.0000	0.0194	0.9806	1.0222	1.0373	1.0623	0	288	14,917	15,205	0.0668%	0.0741%
CILC-1T	180,360	1.0000	0.0000	0.0000	1.0222	1.0373	1.0623	184,369	0	0	184,369	0.8105%	0.8983%
GS(T)-1	1,217,559	0.0000	0.0000	1.0000	1.0222	1.0373	1.0623	0	0	1,293,382	1,293,382	5.6857%	6.3014%
GSCU-1	9,254	0.0000	0.0000	1.0000	1.0222	1.0373	1.0623	0	0	9,830	9,830	0.0432%	0.0479%
GSD(T)-1	4,422,592	0.0000	0.0032	0.9968	1.0222	1.0373	1.0623	0	14,571	4,683,084	4,697,655	20.6510%	22.8871%
GSLD(T)-1	1,673,190	0.0000	0.0355	0.9645	1.0222	1.0373	1.0623	0	61,649	1,714,253	1,775,902	7.8069%	8.6522%
GSLD(T)-2	365,038	0.0000	0.3971	0.6029	1.0222	1.0373	1.0623	0	150,372	233,775	384,147	1.6887%	1.8716%
GSLD(T)-3	35,401	1.0000	0.0000	0.0000	1.0222	1.0373	1.0623	36,188	0	0	36,188	0.1591%	0.1763%
MET	11,941	0.0000	1.0000	0.0000	1.0222	1.0373	1.0623	0	12,386	0	12,386	0.0544%	0.0603%
OL-1	68	0.0000	0.0000	1.0000	1.0222	1.0373	1.0623	0	0	72	72	0.0003%	0.0004%
OS-2	676	0.0000	1.0000	0.0000	1.0222	1.0373	1.0623	0	702	0	702	0.0031%	0.0034%
RS(T)-1	11,040,784	0.0000	0.0000	1.0000	1.0222	1.0373	1.0623	0	0	11,728,341	11,728,341	51.5581%	57.1408%
SL-1	352	0.0000	0.0000	1.0000	1.0222	1.0373	1.0623	0	0	374	374	0.0016%	0.0018%
SL-1M	55	0.0000	0.0000	1.0000	1.0222	1.0373	1.0623	0	0	59	59	0.0003%	0.0003%
SL-2	3,137	0.0000	0.0000	1.0000	1.0222	1.0373	1.0623	0	0	3,333	3,333	0.0147%	0.0162%
SL-2M	140	0.0000	0.0000	1.0000	1.0222	1.0373	1.0623	0	0	149	149	0.0007%	0.0007%
SST-DST	401	0.0000	0.6852	0.3148	1.0222	1.0373	1.0623	0	285	134	419	0.0018%	0.0020%
SST-TST	12,598	1.0000	0.0000	0.0000	1.0222	1.0373	1.0623	12,879	0	0	12,879	0.0566%	0.0627%
TOTAL RETAIL	19,339,613							233,435	393,609	19,898,301	20,525,345	90.2300%	100.0000%
FKEC	126,237	1.0000	0.0000	0.0000	1.0222	1.0373	1.0623	129,043	0	0	129,043	0.5673%	
FPUC (INT)	12,761	1.0000	0.0000	0.0000	1.0222	1.0373	1.0623	13,045	0	0	13,045	0.0573%	
FPUC (PEAK)	9,820	1.0000	0.0000	0.0000	1.0222	1.0373	1.0623	10,038	0	0	10,038	0.0441%	
HOMESTEAD	3,261	1.0000	0.0000	0.0000	1.0222	1.0373	1.0623	3,333	0	0	3,333	0.0147%	
HOMESTEAD (INT)	8,315	1.0000	0.0000	0.0000	1.0222	1.0373	1.0623	8,500	0	0	8,500	0.0374%	
LCEC	762,210	1.0000	0.0000	0.0000	1.0222	1.0373	1.0623	779,152	0	0	779,152	3.4252%	
MOORE HAVEN	571	1.0000	0.0000	0.0000	1.0222	1.0373	1.0623	583	0	0	583	0.0026%	
NEW SMYRNA BCH	7,337	1.0000	0.0000	0.0000	1.0222	1.0373	1.0623	7,500	0	0	7,500	0.0330%	
NEW SMYRNA BEACH (INT)	2,446	1.0000	0.0000	0.0000	1.0222	1.0373	1.0623	2,500	0	0	2,500	0.0110%	
NEW SMYRNA BCH (PEAK)	3,261	1.0000	0.0000	0.0000	1.0222	1.0373	1.0623	3,333	0	0	3,333	0.0147%	
QUINCY	3,098	1.0000	0.0000	0.0000	1.0222	1.0373	1.0623	3,167	0	0	3,167	0.0139%	
SEMINOLE (INT)	81,521	1.0000	0.0000	0.0000	1.0222	1.0373	1.0623	83,333	0	0	83,333	0.3663%	
WAUCHULA	1,875	1.0000	0.0000	0.0000	1.0222	1.0373	1.0623	1,917	0	0	1,917	0.0084%	
TRANS-SERV	1,151,427	1.0000	0.0000	0.0000	1.0222	1.0373	1.0623	1,177,020	0	0	1,177,020	5.1742%	
TOTAL WHOLESALE	2,174,139							2,222,464	0	0	2,222,464	9.7700%	
TOTAL FPL	21,513,752							2,455,899	393,609	19,898,301	22,747,809	100.0000%	
JURIS SEPARATION FACTOR												**0.902300**	

RATE CLASS	12 CP - KW			VOLTAGE LEVEL % - DEMAND			LOSS EXPANSION FACTORS			12 CP @ GENERATION - KW				% OF TOTAL	
	@ METER	ADJ	ADJUSTED	TRANS	PRIMARY	SECOND	TRANS	PRIMARY	SECOND	TRANS	PRIMARY	SECOND	TOTAL	SYSTEM	RETAIL
CILC-1D	351,746	0	351,746	0.0000	0.4203	0.5797	1.0222	1.0373	1.0623	0	153,357	216,599	369,956	1.7247%	1.8024%
CILC-1G	14,320	0	14,320	0.0000	0.0194	0.9806	1.0222	1.0373	1.0623	0	288	14,917	15,205	0.0709%	0.0741%
CILC-1T	180,360	0	180,360	1.0000	0.0000	0.0000	1.0222	1.0373	1.0623	184,369	0	0	184,369	0.8595%	0.8983%
GS(T)-1	1,217,559	0	1,217,559	0.0000	0.0000	1.0000	1.0222	1.0373	1.0623	0	0	1,293,382	1,293,382	6.0297%	6.3014%
GSCU-1	9,254	0	9,254	0.0000	0.0000	1.0000	1.0222	1.0373	1.0623	0	0	9,830	9,830	0.0458%	0.0479%
GSD(T)-1	4,422,592	0	4,422,592	0.0000	0.0032	0.9968	1.0222	1.0373	1.0623	0	14,571	4,683,084	4,697,655	21.9004%	22.8871%
GSLD(T)-1	1,673,190	0	1,673,190	0.0000	0.0355	0.9645	1.0222	1.0373	1.0623	0	61,649	1,714,253	1,775,902	8.2792%	8.6522%
GSLD(T)-2	365,038	0	365,038	0.0000	0.3971	0.6029	1.0222	1.0373	1.0623	0	150,372	233,775	384,147	1.7909%	1.8716%
GSLD(T)-3	35,401	0	35,401	1.0000	0.0000	0.0000	1.0222	1.0373	1.0623	36,188	0	0	36,188	0.1687%	0.1763%
MET	11,941	0	11,941	0.0000	1.0000	0.0000	1.0222	1.0373	1.0623	0	12,386	0	12,386	0.0577%	0.0603%
OL-1	68	0	68	0.0000	0.0000	1.0000	1.0222	1.0373	1.0623	0	0	72	72	0.0003%	0.0004%
OS-2	676	0	676	0.0000	1.0000	0.0000	1.0222	1.0373	1.0623	0	702	0	702	0.0033%	0.0034%
RS(T)-1	11,040,784	0	11,040,784	0.0000	0.0000	1.0000	1.0222	1.0373	1.0623	0	0	11,728,341	11,728,341	54.6775%	57.1408%
SL-1	352	0	352	0.0000	0.0000	1.0000	1.0222	1.0373	1.0623	0	0	374	374	0.0017%	0.0018%
SL-1M	55	0	55	0.0000	0.0000	1.0000	1.0222	1.0373	1.0623	0	0	59	59	0.0003%	0.0003%
SL-2	3,137	0	3,137	0.0000	0.0000	1.0000	1.0222	1.0373	1.0623	0	0	3,333	3,333	0.0155%	0.0162%
SL-2M	140	0	140	0.0000	0.0000	1.0000	1.0222	1.0373	1.0623	0	0	149	149	0.0007%	0.0007%
SST-DST	401	0	401	0.0000	0.6852	0.3148	1.0222	1.0373	1.0623	0	285	134	419	0.0020%	0.0020%
SST-TST	12,598	0	12,598	1.0000	0.0000	0.0000	1.0222	1.0373	1.0623	12,879	0	0	12,879	0.0600%	0.0627%
TOTAL RETAIL	19,339,613	0	19,339,613							233,435	393,609	19,898,301	20,525,345	95.6891%	100.0000%
FKEC	126,237	0	126,237	1.0000	0.0000	0.0000	1.0222	1.0373	1.0623	129,043	0	0	129,043	0.6016%	
FPUC (INT)	12,761	(12,761)	0	1.0000	0.0000	0.0000	1.0222	1.0373	1.0623	0	0	0	0	0.0000%	
FPUC (PEAK)	9,820	(9,820)	0	1.0000	0.0000	0.0000	1.0222	1.0373	1.0623	0	0	0	0	0.0000%	
HOMESTEAD	3,261	0	3,261	1.0000	0.0000	0.0000	1.0222	1.0373	1.0623	3,333	0	0	3,333	0.0155%	
HOMESTEAD (INT)	8,315	(8,315)	0	1.0000	0.0000	0.0000	1.0222	1.0373	1.0623	0	0	0	0	0.0000%	
LCEC	762,210	0	762,210	1.0000	0.0000	0.0000	1.0222	1.0373	1.0623	779,152	0	0	779,152	3.6324%	
MOORE HAVEN	571	0	571	1.0000	0.0000	0.0000	1.0222	1.0373	1.0623	583	0	0	583	0.0027%	
NEW SMYRNA BCH	7,337	0	7,337	1.0000	0.0000	0.0000	1.0222	1.0373	1.0623	7,500	0	0	7,500	0.0350%	
NEW SMYRNA BCH (PEAK)	3,261	(3,261)	0	1.0000	0.0000	0.0000	1.0222	1.0373	1.0623	0	0	0	0	0.0000%	
NEW SMYRNA BEACH (INT)	2,446	(2,446)	0	1.0000	0.0000	0.0000	1.0222	1.0373	1.0623	0	0	0	0	0.0000%	
QUINCY	3,098	0	3,098	1.0000	0.0000	0.0000	1.0222	1.0373	1.0623	3,167	0	0	3,167	0.0148%	
SEMINOLE (INT)	81,521	(81,521)	0	1.0000	0.0000	0.0000	1.0222	1.0373	1.0623	0	0	0	0	0.0000%	
WAUCHULA	1,875	0	1,875	1.0000	0.0000	0.0000	1.0222	1.0373	1.0623	1,917	0	0	1,917	0.0089%	
TOTAL WHOLESALE	1,022,712	(118,124)	904,588							924,694	0	0	924,694	4.3109%	
TOTAL FPL	20,362,325	(118,124)	20,244,201							1,158,130	393,609	19,898,301	21,450,040	100.0000%	
JURIS SEPARATION FACTOR														**0.956891**	

RATE CLASS	12 CP - KW			VOLTAGE LEVEL % - DEMAND			LOSS EXPANSION FACTORS			12 CP @ GENERATION - KW					% OF TOTAL	
	@ METER	ADJ	ADJUSTED	TRANS	PRIMARY	SECOND	TRANS	PRIMARY	SECOND	TRANS	PRIMARY	SECOND	TOTAL	ADJUSTED	SYSTEM	RETAIL
CILC-1D	351,746	0	351,746	0.0000	0.4203	0.5797	1.0222	1.0373	1.0623	0	153,357	216,599	369,956	369,956	1.7125%	1.8024%
CILC-1G	14,320	0	14,320	0.0000	0.0194	0.9806	1.0222	1.0373	1.0623	0	288	14,917	15,205	15,205	0.0704%	0.0741%
CILC-1T	180,360	0	180,360	1.0000	0.0000	0.0000	1.0222	1.0373	1.0623	184,369	0	0	184,369	184,369	0.8534%	0.8983%
GS(T)-1	1,217,559	0	1,217,559	0.0000	0.0000	1.0000	1.0222	1.0373	1.0623	0	0	1,293,382	1,293,382	1,293,382	5.9868%	6.3014%
GSCU-1	9,254	0	9,254	0.0000	0.0000	1.0000	1.0222	1.0373	1.0623	0	0	9,830	9,830	9,830	0.0455%	0.0479%
GSD(T)-1	4,422,592	0	4,422,592	0.0000	0.0032	0.9968	1.0222	1.0373	1.0623	0	14,571	4,683,084	4,697,655	4,697,655	21.7446%	22.8871%
GSLD(T)-1	1,673,190	0	1,673,190	0.0000	0.0355	0.9645	1.0222	1.0373	1.0623	0	61,649	1,714,253	1,775,902	1,775,902	8.2203%	8.6522%
GSLD(T)-2	365,038	0	365,038	0.0000	0.3971	0.6029	1.0222	1.0373	1.0623	0	150,372	233,775	384,147	384,147	1.7781%	1.8716%
GSLD(T)-3	35,401	0	35,401	1.0000	0.0000	0.0000	1.0222	1.0373	1.0623	36,188	0	0	36,188	36,188	0.1675%	0.1763%
MET	11,941	0	11,941	0.0000	1.0000	0.0000	1.0222	1.0373	1.0623	0	12,386	0	12,386	12,386	0.0573%	0.0603%
OL-1	68	0	68	0.0000	0.0000	1.0000	1.0222	1.0373	1.0623	0	0	72	72	72	0.0003%	0.0004%
OS-2	676	0	676	0.0000	1.0000	0.0000	1.0222	1.0373	1.0623	0	702	0	702	702	0.0032%	0.0034%
RS(T)-1	11,040,784	0	11,040,784	0.0000	0.0000	1.0000	1.0222	1.0373	1.0623	0	0	11,728,341	11,728,341	11,728,341	54.2884%	57.1408%
SL-1	352	0	352	0.0000	0.0000	1.0000	1.0222	1.0373	1.0623	0	0	374	374	374	0.0017%	0.0018%
SL-1M	55	0	55	0.0000	0.0000	1.0000	1.0222	1.0373	1.0623	0	0	59	59	59	0.0003%	0.0003%
SL-2	3,137	0	3,137	0.0000	0.0000	1.0000	1.0222	1.0373	1.0623	0	0	3,333	3,333	3,333	0.0154%	0.0162%
SL-2M	140	0	140	0.0000	0.0000	1.0000	1.0222	1.0373	1.0623	0	0	149	149	149	0.0007%	0.0007%
SST-DST	401	0	401	0.0000	0.6852	0.3148	1.0222	1.0373	1.0623	0	285	134	419	419	0.0019%	0.0020%
SST-TST	12,598	0	12,598	1.0000	0.0000	0.0000	1.0222	1.0373	1.0623	12,879	0	0	12,879	12,879	0.0596%	0.0627%
TOTAL RETAIL	19,339,613	0	19,339,613							233,435	393,609	19,898,301	20,525,345	20,525,345	95.0081%	100.0000%
FKEC	126,237	0	126,237	1.0000	0.0000	0.0000	1.0222	1.0373	1.0623	129,043	0	0	129,043	129,043	0.5973%	
FPUC (INT)	12,761	0	12,761	1.0000	0.0000	0.0000	1.0222	1.0373	1.0623	13,045	0	0	13,045	**18,677**	0.0865%	
FPUC (PEAK)	9,820	(9,820)	0	1.0000	0.0000	0.0000	1.0222	1.0373	1.0623	0	0	0	0	0	0.0000%	
HOMESTEAD	3,261	0	3,261	1.0000	0.0000	0.0000	1.0222	1.0373	1.0623	3,333	0	0	3,333	3,333	0.0154%	
HOMESTEAD (INT)	8,315	0	8,315	1.0000	0.0000	0.0000	1.0222	1.0373	1.0623	8,500	0	0	8,500	**12,170**	0.0563%	
LCEC	762,210	0	762,210	1.0000	0.0000	0.0000	1.0222	1.0373	1.0623	779,152	0	0	779,152	779,152	3.6066%	
MOORE HAVEN	571	0	571	1.0000	0.0000	0.0000	1.0222	1.0373	1.0623	583	0	0	583	583	0.0027%	
NEW SMYRNA BCH	7,337	0	7,337	1.0000	0.0000	0.0000	1.0222	1.0373	1.0623	7,500	0	0	7,500	7,500	0.0347%	
NEW SMYRNA BCH (PEAK)	3,261	(3,261)	0	1.0000	0.0000	0.0000	1.0222	1.0373	1.0623	0	0	0	0	0	0.0000%	
NEW SMYRNA BEACH (INT)	2,446	0	2,446	1.0000	0.0000	0.0000	1.0222	1.0373	1.0623	2,500	0	0	2,500	**3,579**	0.0166%	
QUINCY	3,098	0	3,098	1.0000	0.0000	0.0000	1.0222	1.0373	1.0623	3,167	0	0	3,167	3,167	0.0147%	
SEMINOLE (INT)	81,521	0	81,521	1.0000	0.0000	0.0000	1.0222	1.0373	1.0623	83,333	0	0	83,333	**119,312**	0.5523%	
WAUCHULA	1,875	0	1,875	1.0000	0.0000	0.0000	1.0222	1.0373	1.0623	1,917	0	0	1,917	1,917	0.0089%	
TOTAL WHOLESALE	1,022,712	(13,081)	1,009,631							1,032,073	0	0	1,032,073	1,078,432	4.9919%	
TOTAL FPL	20,362,325	(13,081)	20,349,245							1,265,508	393,609	19,898,301	21,557,418	21,603,778	100.0000%	
JURIS SEPARATION FACTOR															**0.950081**	

RATE CLASS	12 CP - KW			VOLTAGE LEVEL % - DEMAND			LOSS EXPANSION FACTORS			12 CP @ GENERATION - KW					% OF TOTAL	
	@ METER	ADJ	ADJUSTED	TRANS	PRIMARY	SECOND	TRANS	PRIMARY	SECOND	TRANS	PRIMARY	SECOND	TOTAL	ADJUSTED	SYSTEM	RETAIL

Contract Adjusted 12CP @ Generation -	Line No.	Source/Formula	FPUC (INT) Amount	HOMESTEAD (INT) Amount	NSB (INT) Amount	SEMINOLE (INT) Amount
1) Contract Wholesale Customer 12 CP	1	Load Forecast * Loss Factor	13,045	8,500	2,500	83,333
2) Intermediate System Capacity Net of Reserve Margin	2					
Intermediate Summer Capacity	3	2020-2029 TYSP	18,107,000	18,107,000	18,107,000	18,107,000
Divide By: System Capacity Including Reserve Margin (Calculation)	4		120.0%	120.0%	120.0%	120.0%
Intermediate System Capacity Net of Reserve Margin	5	L3 / L4	15,089,167	15,089,167	15,089,167	15,089,167
Contract Wholesale Customer Contribution to Intermediate System Capacity Net of Reserve Margin	6	L1 / L5	0.000865	0.000563	0.000166	0.005523
3) Contract Adjusted 12CP @ Generation	7					
Total System 12CP Excluding All Stratified Contracts	8		21,450,040	21,450,040	21,450,040	21,450,040
Contribution (Excluding Intermediate Stratified Contracts) to Other Production System Capacity Net of Reserve Margin	9	1 - Sum L6	0.99288	0.99288	0.99288	0.99288
Total System 12CP Including Intermediate Stratified Contracts	10	L8 / L9	21,603,778	21,603,778	21,603,778	21,603,778
Contract Adjusted 12CP @ Generation	11	L6 * L11	18,677	12,170	3,579	119,312

RATE CLASS	12 CP - KW			VOLTAGE LEVEL % - DEMAND			LOSS EXPANSION FACTORS			12 CP @ GENERATION - KW					% OF TOTAL	
	@ METER	ADJ	ADJUSTED	TRANS	PRIMARY	SECOND	TRANS	PRIMARY	SECOND	TRANS	PRIMARY	SECOND	TOTAL	ADJUSTED	SYSTEM	RETAIL
CILC-1D	351,746	0	351,746	0.0000	0.4203	0.5797	1.0222	1.0373	1.0623	0	153,357	216,599	369,956	369,956	1.7173%	1.8024%
CILC-1G	14,320	0	14,320	0.0000	0.0194	0.9806	1.0222	1.0373	1.0623	0	288	14,917	15,205	15,205	0.0706%	0.0741%
CILC-1T	180,360	0	180,360	1.0000	0.0000	0.0000	1.0222	1.0373	1.0623	184,369	0	0	184,369	184,369	0.8558%	0.8983%
GS(T)-1	1,217,559	0	1,217,559	0.0000	0.0000	1.0000	1.0222	1.0373	1.0623	0	0	1,293,382	1,293,382	1,293,382	6.0038%	6.3014%
GSCU-1	9,254	0	9,254	0.0000	0.0000	1.0000	1.0222	1.0373	1.0623	0	0	9,830	9,830	9,830	0.0456%	0.0479%
GSD(T)-1	4,422,592	0	4,422,592	0.0000	0.0032	0.9968	1.0222	1.0373	1.0623	0	14,571	4,683,084	4,697,655	4,697,655	21.8063%	22.8871%
GSLD(T)-1	1,673,190	0	1,673,190	0.0000	0.0355	0.9645	1.0222	1.0373	1.0623	0	61,649	1,714,253	1,775,902	1,775,902	8.2437%	8.6522%
GSLD(T)-2	365,038	0	365,038	0.0000	0.3971	0.6029	1.0222	1.0373	1.0623	0	150,372	233,775	384,147	384,147	1.7832%	1.8716%
GSLD(T)-3	35,401	0	35,401	1.0000	0.0000	0.0000	1.0222	1.0373	1.0623	36,188	0	0	36,188	36,188	0.1680%	0.1763%
MET	11,941	0	11,941	0.0000	1.0000	0.0000	1.0222	1.0373	1.0623	0	12,386	0	12,386	12,386	0.0575%	0.0603%
OL-1	68	0	68	0.0000	0.0000	1.0000	1.0222	1.0373	1.0623	0	0	72	72	72	0.0003%	0.0004%
OS-2	676	0	676	0.0000	1.0000	0.0000	1.0222	1.0373	1.0623	0	702	0	702	702	0.0033%	0.0034%
RS(T)-1	11,040,784	0	11,040,784	0.0000	0.0000	1.0000	1.0222	1.0373	1.0623	0	0	11,728,341	11,728,341	11,728,341	54.4425%	57.1408%
SL-1	352	0	352	0.0000	0.0000	1.0000	1.0222	1.0373	1.0623	0	0	374	374	374	0.0017%	0.0018%
SL-1M	55	0	55	0.0000	0.0000	1.0000	1.0222	1.0373	1.0623	0	0	59	59	59	0.0003%	0.0003%
SL-2	3,137	0	3,137	0.0000	0.0000	1.0000	1.0222	1.0373	1.0623	0	0	3,333	3,333	3,333	0.0155%	0.0162%
SL-2M	140	0	140	0.0000	0.0000	1.0000	1.0222	1.0373	1.0623	0	0	149	149	149	0.0007%	0.0007%
SST-DST	401	0	401	0.0000	0.6852	0.3148	1.0222	1.0373	1.0623	0	285	134	419	419	0.0019%	0.0020%
SST-TST	12,598	0	12,598	1.0000	0.0000	0.0000	1.0222	1.0373	1.0623	12,879	0	0	12,879	12,879	0.0598%	0.0627%
TOTAL RETAIL	19,339,613	0	19,339,613							233,435	393,609	19,898,301	20,525,345	20,525,345	95.2778%	100.0000%
FKEC	126,237	0	126,237	1.0000	0.0000	0.0000	1.0222	1.0373	1.0623	129,043	0	0	129,043	129,043	0.5990%	
FPUC (INT)	12,761	(12,761)	0	1.0000	0.0000	0.0000	1.0222	1.0373	1.0623	0	0	0	0	0	0.0000%	
FPUC (PEAK)	9,820	0	9,820	1.0000	0.0000	0.0000	1.0222	1.0373	1.0623	10,038	0	0	10,038	**69,515**	0.3227%	
HOMESTEAD	3,261	0	3,261	1.0000	0.0000	0.0000	1.0222	1.0373	1.0623	3,333	0	0	3,333	3,333	0.0155%	
HOMESTEAD (INT)	8,315	(8,315)	0	1.0000	0.0000	0.0000	1.0222	1.0373	1.0623	0	0	0	0	0	0.0000%	
LCEC	762,210	0	762,210	1.0000	0.0000	0.0000	1.0222	1.0373	1.0623	779,152	0	0	779,152	779,152	3.6168%	
MOORE HAVEN	571	0	571	1.0000	0.0000	0.0000	1.0222	1.0373	1.0623	583	0	0	583	583	0.0027%	
NEW SMYRNA BCH	7,337	0	7,337	1.0000	0.0000	0.0000	1.0222	1.0373	1.0623	7,500	0	0	7,500	7,500	0.0348%	
NEW SMYRNA BCH (PEAK)	3,261	0	3,261	1.0000	0.0000	0.0000	1.0222	1.0373	1.0623	3,333	0	0	3,333	**23,083**	0.1072%	
NEW SMYRNA BEACH (INT)	2,446	(2,446)	0	1.0000	0.0000	0.0000	1.0222	1.0373	1.0623	0	0	0	0	0	0.0000%	
QUINCY	3,098	0	3,098	1.0000	0.0000	0.0000	1.0222	1.0373	1.0623	3,167	0	0	3,167	3,167	0.0147%	
SEMINOLE (INT)	81,521	(81,521)	0	1.0000	0.0000	0.0000	1.0222	1.0373	1.0623	0	0	0	0	0	0.0000%	
WAUCHULA	1,875	0	1,875	1.0000	0.0000	0.0000	1.0222	1.0373	1.0623	1,917	0	0	1,917	1,917	0.0089%	
TOTAL WHOLESALE	1,022,712	(105,044)	917,669							938,066	0	0	938,066	1,017,293	4.7222%	
TOTAL FPL	20,362,325	(105,044)	20,257,282							1,171,501	393,609	19,898,301	21,463,411	21,542,638	100.0000%	
JURIS SEPARATION FACTOR															**0.952778**	

RATE CLASS	12 CP - KW			VOLTAGE LEVEL % - DEMAND			LOSS EXPANSION FACTORS			12 CP @ GENERATION - KW					% OF TOTAL	
	@ METER	ADJ	ADJUSTED	TRANS	PRIMARY	SECOND	TRANS	PRIMARY	SECOND	TRANS	PRIMARY	SECOND	TOTAL	ADJUSTED	SYSTEM	RETAIL

	Line No.	Source/Formula	FPUC (PEAK) Amount	NSB (PEAK) Amount
Contract Adjusted 12CP @ Generation -				
1) Contract Wholesale Customer 12 CP	1	Load Forecast * Loss Factor	10,038	3,333
2) Peaking System Capacity Net of Reserve Margin	2			
Peaking Summer Capacity	3	2020-2029 TYSP	3,733,000	3,733,000
Divide By: System Capacity Including Reserve Margin (Calculation)	4		120.0%	120.0%
Peaking System Capacity Net of Reserve Margin	5	L3 / L4	3,110,833	3,110,833
Contract Wholesale Customer Contribution to Intermediate System Capacity Net of Reserve Margin	6	L1 / L5	0.00323	0.00107
3) Contract Adjusted 12CP @ Generation	7			
Total System 12CP Excluding All Stratified Contracts	8		21,450,040	21,450,040
Contribution (Excluding Peaking Stratified Contracts) to Other Production System Capacity Net of Reserve Margin	9	1 - Sum L6	0.99570	0.99570
Total System 12CP Including Intermediate Stratified Contracts	10	L8 / L9	21,542,638	21,542,638
Contract Adjusted 12CP @ Generation	11	L6 * L11	69,515	23,083

RATE CLASS	MAX GNCP			VOLTAGE LEVEL % - DEMAND		LOSS EXPANSION FACTORS		MAX GNCP @ GENERATION			% OF TOTAL	
	@ METER	ADJ	ADJUSTED	PRIMARY	SECOND	PRIMARY	SECOND	PRIMARY	SECOND	TOTAL	SYSTEM	RETAIL
CILC-1D	381,582	0	381,582	0.4203	0.5797	1.0373	1.0623	166,365	234,971	401,336	1.5990%	1.5990%
CILC-1G	16,072	0	16,072	0.0194	0.9806	1.0373	1.0623	323	16,742	17,065	0.0680%	0.0680%
CILC-1T	210,921	(210,921)	0	0.0000	0.0000	1.0373	1.0623	0	0	0	0.0000%	0.0000%
GS(T)-1	1,432,038	0	1,432,038	0.0000	1.0000	1.0373	1.0623	0	1,521,218	1,521,218	6.0606%	6.0606%
GSCU-1	10,078	0	10,078	0.0000	1.0000	1.0373	1.0623	0	10,706	10,706	0.0427%	0.0427%
GSD(T)-1	4,999,674	0	4,999,674	0.0032	0.9968	1.0373	1.0623	16,473	5,294,156	5,310,629	21.1579%	21.1579%
GSLD(T)-1	1,986,886	0	1,986,886	0.0355	0.9645	1.0373	1.0623	73,207	2,035,647	2,108,854	8.4018%	8.4018%
GSLD(T)-2	423,490	0	423,490	0.3971	0.6029	1.0373	1.0623	174,450	271,209	445,659	1.7755%	1.7755%
GSLD(T)-3	42,860	(42,860)	0	0.0000	0.0000	1.0373	1.0623	0	0	0	0.0000%	0.0000%
MET	14,644	0	14,644	1.0000	0.0000	1.0373	1.0623	15,189	0	15,189	0.0605%	0.0605%
OL-1	25,140	0	25,140	0.0000	1.0000	1.0373	1.0623	0	26,706	26,706	0.1064%	0.1064%
OS-2	8,295	0	8,295	1.0000	0.0000	1.0373	1.0623	8,604	0	8,604	0.0343%	0.0343%
RS(T)-1	14,201,390	0	14,201,390	0.0000	1.0000	1.0373	1.0623	0	15,085,772	15,085,772	60.1027%	60.1027%
SL-1	127,448	0	127,448	0.0000	1.0000	1.0373	1.0623	0	135,385	135,385	0.5394%	0.5394%
SL-1M	2,340	0	2,340	0.0000	1.0000	1.0373	1.0623	0	2,486	2,486	0.0099%	0.0099%
SL-2	3,376	0	3,376	0.0000	1.0000	1.0373	1.0623	0	3,586	3,586	0.0143%	0.0143%
SL-2M	268	0	268	0.0000	1.0000	1.0373	1.0623	0	284	284	0.0011%	0.0011%
SST-DST	6,217	0	6,217	0.6852	0.3148	1.0373	1.0623	4,419	2,079	6,498	0.0259%	0.0259%
SST-TST	71,558	(71,558)	0	0.0000	0.0000	1.0373	1.0623	0	0	0	0.0000%	0.0000%
TOTAL RETAIL	23,964,276	(325,339)	23,638,937					459,030	24,640,946	25,099,976	100.0000%	100.0000%
FKEC	154,278	(154,278)	0	0.0000	0.0000	1.0373	1.0623	0	0	0	0.0000%	
FPUC (INT)	14,001	(14,001)	0	0.0000	0.0000	1.0373	1.0623	0	0	0	0.0000%	
FPUC (PEAK)	33,469	(33,469)	0	0.0000	0.0000	1.0373	1.0623	0	0	0	0.0000%	
HOMESTEAD	25,001	(25,001)	0	0.0000	0.0000	1.0373	1.0623	0	0	0	0.0000%	
HOMESTEAD (INT)	51,001	(51,001)	0	0.0000	0.0000	1.0373	1.0623	0	0	0	0.0000%	
LCEC	1,012,512	(1,012,512)	0	0.0000	0.0000	1.0373	1.0623	0	0	0	0.0000%	
MOORE HAVEN	4,001	(4,001)	0	0.0000	0.0000	1.0373	1.0623	0	0	0	0.0000%	
NEW SMYRNA BCH	45,001	(45,001)	0	0.0000	0.0000	1.0373	1.0623	0	0	0	0.0000%	
NEW SMYRNA BEACH (INT)	20,001	(20,001)	0	0.0000	0.0000	1.0373	1.0623	0	0	0	0.0000%	
NEW SMYRNA BCH (PEAK)	20,001	(20,001)	0	0.0000	0.0000	1.0373	1.0623	0	0	0	0.0000%	
QUINCY	19,001	(19,001)	0	0.0000	0.0000	1.0373	1.0623	0	0	0	0.0000%	
SEMINOLE (INT)	200,001	(200,001)	0	0.0000	0.0000	1.0373	1.0623	0	0	0	0.0000%	
WAUCHULA	14,001	(14,001)	0	0.0000	0.0000	1.0373	1.0623	0	0	0	0.0000%	
TOTAL WHOLESALE	1,612,269	(1,612,269)	0					0	0	0	0.0000%	
TOTAL FPL	25,576,545	(1,937,608)	23,638,937					459,030	24,640,946	25,099,976	100.0000%	
JURIS SEPARATION FACTOR											**1.000000**	

RATE CLASS	MWH SALES	VOLTAGE LEVEL %			LOSS EXPANSION FACTORS			MWH SALES @ GENERATION				% OF TOTAL	
	@ METER	TRANS	PRIMARY	SECONDARY	TRANS	PRIMARY	SECOND	TRANS	PRIMARY	SECOND	TOTAL	SYSTEM	RETAIL
CILC-1D	2,635,788	0.0000	0.4148	0.5852	1.0169	1.0282	1.0468	0	1,124,208	1,614,572	2,738,780	2.2298%	2.3420%
CILC-1G	104,193	0.0000	0.0182	0.9818	1.0169	1.0282	1.0468	0	1,951	107,085	109,036	0.0888%	0.0932%
CILC-1T	1,470,591	1.0000	0.0000	0.0000	1.0169	1.0282	1.0468	1,495,380	0	0	1,495,380	1.2175%	1.2787%
GS(T)-1	6,506,169	0.0000	0.0000	1.0000	1.0169	1.0282	1.0468	0	0	6,810,760	6,810,760	5.5450%	5.8240%
GSCU-1	77,567	0.0000	0.0000	1.0000	1.0169	1.0282	1.0468	0	0	81,199	81,199	0.0661%	0.0694%
GSD(T)-1	27,339,373	0.0000	0.0032	0.9968	1.0169	1.0282	1.0468	0	91,279	28,526,352	28,617,631	23.2989%	24.4715%
GSLD(T)-1	10,202,111	0.0000	0.0343	0.9657	1.0169	1.0282	1.0468	0	359,942	10,313,256	10,673,197	8.6895%	9.1269%
GSLD(T)-2	2,700,592	0.0000	0.3964	0.6036	1.0169	1.0282	1.0468	0	1,100,605	1,706,441	2,807,046	2.2853%	2.4004%
GSLD(T)-3	259,243	1.0000	0.0000	0.0000	1.0169	1.0282	1.0468	263,612	0	0	263,612	0.2146%	0.2254%
MET	80,326	0.0000	1.0000	0.0000	1.0169	1.0282	1.0468	0	82,587	0	82,587	0.0672%	0.0706%
OL-1	92,432	0.0000	0.0000	1.0000	1.0169	1.0282	1.0468	0	0	96,759	96,759	0.0788%	0.0827%
OS-2	9,166	0.0000	1.0000	0.0000	1.0169	1.0282	1.0468	0	9,424	0	9,424	0.0077%	0.0081%
RS(T)-1	59,729,074	0.0000	0.0000	1.0000	1.0169	1.0282	1.0468	0	0	62,525,339	62,525,339	50.9048%	53.4667%
SL-1	474,786	0.0000	0.0000	1.0000	1.0169	1.0282	1.0468	0	0	497,013	497,013	0.4046%	0.4250%
SL-1M	8,734	0.0000	0.0000	1.0000	1.0169	1.0282	1.0468	0	0	9,143	9,143	0.0074%	0.0078%
SL-2	26,432	0.0000	0.0000	1.0000	1.0169	1.0282	1.0468	0	0	27,669	27,669	0.0225%	0.0237%
SL-2M	1,665	0.0000	0.0000	1.0000	1.0169	1.0282	1.0468	0	0	1,743	1,743	0.0014%	0.0015%
SST-DST	1,850	0.0000	0.5444	0.4556	1.0169	1.0282	1.0468	0	1,035	882	1,918	0.0016%	0.0016%
SST-TST	92,788	1.0000	0.0000	0.0000	1.0169	1.0282	1.0468	94,352	0	0	94,352	0.0768%	0.0807%
TOTAL RETAIL	111,812,880							1,853,345	2,771,031	112,318,213	116,942,590	95.2084%	100.0000%
FKEC	805,763	1.0000	0.0000	0.0000	1.0169	1.0282	1.0468	819,345	0	0	819,345	0.6671%	
FPUC (INT)	101,728	1.0000	0.0000	0.0000	1.0169	1.0282	1.0468	103,443	0	0	103,443	0.0842%	
FPUC (PEAK)	53,455	1.0000	0.0000	0.0000	1.0169	1.0282	1.0468	54,356	0	0	54,356	0.0443%	
HOMESTEAD	160	1.0000	0.0000	0.0000	1.0169	1.0282	1.0468	163	0	0	163	0.0001%	
HOMESTEAD (INT)	408	1.0000	0.0000	0.0000	1.0169	1.0282	1.0468	415	0	0	415	0.0003%	
LCEC	4,387,467	1.0000	0.0000	0.0000	1.0169	1.0282	1.0468	4,461,425	0	0	4,461,425	3.6323%	
MOORE HAVEN	28	1.0000	0.0000	0.0000	1.0169	1.0282	1.0468	28	0	0	28	0.0000%	
NEW SMYRNA BCH	360	1.0000	0.0000	0.0000	1.0169	1.0282	1.0468	366	0	0	366	0.0003%	
NEW SMYRNA BEACH (INT)	12,120	1.0000	0.0000	0.0000	1.0169	1.0282	1.0468	12,324	0	0	12,324	0.0100%	
NEW SMYRNA BCH (PEAK)	160	1.0000	0.0000	0.0000	1.0169	1.0282	1.0468	163	0	0	163	0.0001%	
QUINCY	152	1.0000	0.0000	0.0000	1.0169	1.0282	1.0468	155	0	0	155	0.0001%	
SEMINOLE (INT)	425,973	1.0000	0.0000	0.0000	1.0169	1.0282	1.0468	433,153	0	0	433,153	0.3527%	
WAUCHULA	92	1.0000	0.0000	0.0000	1.0169	1.0282	1.0468	94	0	0	94	0.0001%	
TOTAL WHOLESALE	5,787,865							5,885,429	0	0	5,885,429	4.7916%	
TOTAL FPL	117,600,745							7,738,774	2,771,031	112,318,213	122,828,019	100.0000%	
JURIS SEPARATION FACTOR												**0.952084**	

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RATE CLASS	MWH SALES			VOLTAGE LEVEL %			LOSS EXPANSION FACTORS			MWH SALES @ GENERATION				% OF TOTAL	
	@ METER	ADJ	ADJUSTED	TRANS	PRIMARY	SECONDARY	TRANS	PRIMARY	SECOND	TRANS	PRIMARY	SECOND	TOTAL	SYSTEM	RETAIL
CILC-1D	2,635,788	0	2,635,788	0.0000	0.4148	0.5852	1.0169	1.0282	1.0468	0	1,124,208	1,614,572	2,738,780	2.2408%	2.3420%
CILC-1G	104,193	0	104,193	0.0000	0.0182	0.9818	1.0169	1.0282	1.0468	0	1,951	107,085	109,036	0.0892%	0.0932%
CILC-1T	1,470,591	0	1,470,591	1.0000	0.0000	0.0000	1.0169	1.0282	1.0468	1,495,380	0	0	1,495,380	1.2235%	1.2787%
GS(T)-1	6,506,169	0	6,506,169	0.0000	0.0000	1.0000	1.0169	1.0282	1.0468	0	0	6,810,760	6,810,760	5.5724%	5.8240%
GSCU-1	77,567	0	77,567	0.0000	0.0000	1.0000	1.0169	1.0282	1.0468	0	0	81,199	81,199	0.0664%	0.0694%
GSD(T)-1	27,339,373	0	27,339,373	0.0000	0.0032	0.9968	1.0169	1.0282	1.0468	0	91,279	28,526,352	28,617,631	23.4141%	24.4715%
GSLD(T)-1	10,202,111	0	10,202,111	0.0000	0.0343	0.9657	1.0169	1.0282	1.0468	0	359,942	10,313,256	10,673,197	8.7325%	9.1269%
GSLD(T)-2	2,700,592	0	2,700,592	0.0000	0.3964	0.6036	1.0169	1.0282	1.0468	0	1,100,605	1,706,441	2,807,046	2.2966%	2.4004%
GSLD(T)-3	259,243	0	259,243	1.0000	0.0000	0.0000	1.0169	1.0282	1.0468	263,612	0	0	263,612	0.2157%	0.2254%
MET	80,326	0	80,326	0.0000	1.0000	0.0000	1.0169	1.0282	1.0468	0	82,587	0	82,587	0.0676%	0.0706%
OL-1	92,432	0	92,432	0.0000	0.0000	1.0000	1.0169	1.0282	1.0468	0	0	96,759	96,759	0.0792%	0.0827%
OS-2	9,166	0	9,166	0.0000	1.0000	0.0000	1.0169	1.0282	1.0468	0	9,424	0	9,424	0.0077%	0.0081%
RS(T)-1	59,729,074	0	59,729,074	0.0000	0.0000	1.0000	1.0169	1.0282	1.0468	0	0	62,525,339	62,525,339	51.1563%	53.4667%
SL-1	474,786	0	474,786	0.0000	0.0000	1.0000	1.0169	1.0282	1.0468	0	0	497,013	497,013	0.4066%	0.4250%
SL-1M	8,734	0	8,734	0.0000	0.0000	1.0000	1.0169	1.0282	1.0468	0	0	9,143	9,143	0.0075%	0.0078%
SL-2	26,432	0	26,432	0.0000	0.0000	1.0000	1.0169	1.0282	1.0468	0	0	27,669	27,669	0.0226%	0.0237%
SL-2M	1,665	0	1,665	0.0000	0.0000	1.0000	1.0169	1.0282	1.0468	0	0	1,743	1,743	0.0014%	0.0015%
SST-DST	1,850	0	1,850	0.0000	0.5444	0.4556	1.0169	1.0282	1.0468	0	1,035	882	1,918	0.0016%	0.0016%
SST-TST	92,788	0	92,788	1.0000	0.0000	0.0000	1.0169	1.0282	1.0468	94,352	0	0	94,352	0.0772%	0.0807%
TOTAL RETAIL	111,812,880	0	111,812,880							1,853,345	2,771,031	112,318,213	116,942,590	95.6788%	100.0000%
FKEC	805,763	0	805,763	1.0000	0.0000	0.0000	1.0169	1.0282	1.0468	819,345	0	0	819,345	0.6704%	
FPUC (INT)	101,728	(101,728)	0	1.0000	0.0000	0.0000	1.0169	1.0282	1.0468	0	0	0	0	0.0000%	
FPUC (PEAK)	53,455	(53,455)	0	1.0000	0.0000	0.0000	1.0169	1.0282	1.0468	0	0	0	0	0.0000%	
HOMESTEAD	160	0	160	1.0000	0.0000	0.0000	1.0169	1.0282	1.0468	163	0	0	163	0.0001%	
HOMESTEAD (INT)	408	(408)	0	1.0000	0.0000	0.0000	1.0169	1.0282	1.0468	0	0	0	0	0.0000%	
LCEC	4,387,467	0	4,387,467	1.0000	0.0000	0.0000	1.0169	1.0282	1.0468	4,461,425	0	0	4,461,425	3.6502%	
MOORE HAVEN	28	0	28	1.0000	0.0000	0.0000	1.0169	1.0282	1.0468	28	0	0	28	0.0000%	
NEW SMYRNA BCH	360	0	360	1.0000	0.0000	0.0000	1.0169	1.0282	1.0468	366	0	0	366	0.0003%	
NEW SMYRNA BCH (PEAK)	160	(160)	0	1.0000	0.0000	0.0000	1.0169	1.0282	1.0468	0	0	0	0	0.0000%	
NEW SMYRNA BEACH (INT)	12,120	(12,120)	0	1.0000	0.0000	0.0000	1.0169	1.0282	1.0468	0	0	0	0	0.0000%	
QUINCY	152	0	152	1.0000	0.0000	0.0000	1.0169	1.0282	1.0468	155	0	0	155	0.0001%	
SEMINOLE (INT)	425,973	(425,973)	0	1.0000	0.0000	0.0000	1.0169	1.0282	1.0468	0	0	0	0	0.0000%	
WAUCHULA	92	0	92	1.0000	0.0000	0.0000	1.0169	1.0282	1.0468	94	0	0	94	0.0001%	
TOTAL WHOLESALE	5,787,865	(593,844)	5,194,021							5,281,575	0	0	5,281,575	4.3212%	
TOTAL FPL	117,600,745	(593,844)	117,006,901							7,134,920	2,771,031	112,318,213	122,224,164	100.0000%	
JURIS SEPARATION FACTOR														**0.956788**	

RATE CLASS	MWH SALES			VOLTAGE LEVEL %			LOSS EXPANSION FACTORS			MWH SALES @ GENERATION					% OF TOTAL	
	@ METER	ADJ	ADJUSTED	TRANS	PRIMARY	SECONDARY	TRANS	PRIMARY	SECOND	TRANS	PRIMARY	SECOND	TOTAL	ADJUSTED	SYSTEM	RETAIL
CILC-1D	2,635,788	0	2,635,788	0.0000	0.4148	0.5852	1.0169	1.0282	1.0468	0	1,124,208	1,614,572	2,738,780	2,738,780	2.2248%	2.3420%
CILC-1G	104,193	0	104,193	0.0000	0.0182	0.9818	1.0169	1.0282	1.0468	0	1,951	107,085	109,036	109,036	0.0886%	0.0932%
CILC-1T	1,470,591	0	1,470,591	1.0000	0.0000	0.0000	1.0169	1.0282	1.0468	1,495,380	0	0	1,495,380	1,495,380	1.2148%	1.2787%
GS(T)-1	6,506,169	0	6,506,169	0.0000	0.0000	1.0000	1.0169	1.0282	1.0468	0	0	6,810,760	6,810,760	6,810,760	5.5327%	5.8240%
GSCU-1	77,567	0	77,567	0.0000	0.0000	1.0000	1.0169	1.0282	1.0468	0	0	81,199	81,199	81,199	0.0660%	0.0694%
GSD(T)-1	27,339,373	0	27,339,373	0.0000	0.0032	0.9968	1.0169	1.0282	1.0468	0	91,279	28,526,352	28,617,631	28,617,631	23.2474%	24.4715%
GSLD(T)-1	10,202,111	0	10,202,111	0.0000	0.0343	0.9657	1.0169	1.0282	1.0468	0	359,942	10,313,256	10,673,197	10,673,197	8.6703%	9.1269%
GSLD(T)-2	2,700,592	0	2,700,592	0.0000	0.3964	0.6036	1.0169	1.0282	1.0468	0	1,100,605	1,706,441	2,807,046	2,807,046	2.2803%	2.4004%
GSLD(T)-3	259,243	0	259,243	1.0000	0.0000	0.0000	1.0169	1.0282	1.0468	263,612	0	0	263,612	263,612	0.2141%	0.2254%
MET	80,326	0	80,326	0.0000	1.0000	0.0000	1.0169	1.0282	1.0468	0	82,587	0	82,587	82,587	0.0671%	0.0706%
OL-1	92,432	0	92,432	0.0000	0.0000	1.0000	1.0169	1.0282	1.0468	0	0	96,759	96,759	96,759	0.0786%	0.0827%
OS-2	9,166	0	9,166	0.0000	1.0000	0.0000	1.0169	1.0282	1.0468	0	9,424	0	9,424	9,424	0.0077%	0.0081%
RS(T)-1	59,729,074	0	59,729,074	0.0000	0.0000	1.0000	1.0169	1.0282	1.0468	0	0	62,525,339	62,525,339	62,525,339	50.7922%	53.4667%
SL-1	474,786	0	474,786	0.0000	0.0000	1.0000	1.0169	1.0282	1.0468	0	0	497,013	497,013	497,013	0.4037%	0.4250%
SL-1M	8,734	0	8,734	0.0000	0.0000	1.0000	1.0169	1.0282	1.0468	0	0	9,143	9,143	9,143	0.0074%	0.0078%
SL-2	26,432	0	26,432	0.0000	0.0000	1.0000	1.0169	1.0282	1.0468	0	0	27,669	27,669	27,669	0.0225%	0.0237%
SL-2M	1,665	0	1,665	0.0000	0.0000	1.0000	1.0169	1.0282	1.0468	0	0	1,743	1,743	1,743	0.0014%	0.0015%
SST-DST	1,850	0	1,850	0.0000	0.5444	0.4556	1.0169	1.0282	1.0468	0	1,035	882	1,918	1,918	0.0016%	0.0016%
SST-TST	92,788	0	92,788	1.0000	0.0000	0.0000	1.0169	1.0282	1.0468	94,352	0	0	94,352	94,352	0.0766%	0.0807%
TOTAL RETAIL	111,812,880	0	111,812,880							1,853,345	2,771,031	112,318,213	116,942,590	116,942,590	94.9979%	100.0000%
FKEC	805,763	0	805,763	1.0000	0.0000	0.0000	1.0169	1.0282	1.0468	819,345	0	0	819,345	819,345	0.6656%	
FPUC (INT)	101,728	0	101,728	1.0000	0.0000	0.0000	1.0169	1.0282	1.0468	103,443	0	0	103,443	**106,424**	0.0865%	
FPUC (PEAK)	53,455	(53,455)	0	1.0000	0.0000	0.0000	1.0169	1.0282	1.0468	0	0	0	0	0	0.0000%	
HOMESTEAD	160	0	160	1.0000	0.0000	0.0000	1.0169	1.0282	1.0468	163	0	0	163	163	0.0001%	
HOMESTEAD (INT)	408	0	408	1.0000	0.0000	0.0000	1.0169	1.0282	1.0468	415	0	0	415	**69,345**	0.0563%	
LCEC	4,387,467	0	4,387,467	1.0000	0.0000	0.0000	1.0169	1.0282	1.0468	4,461,425	0	0	4,461,425	4,461,425	3.6242%	
MOORE HAVEN	28	0	28	1.0000	0.0000	0.0000	1.0169	1.0282	1.0468	28	0	0	28	28	0.0000%	
NEW SMYRNA BCH	360	0	360	1.0000	0.0000	0.0000	1.0169	1.0282	1.0468	366	0	0	366	366	0.0003%	
NEW SMYRNA BCH (PEAK)	160	(160)	0	1.0000	0.0000	0.0000	1.0169	1.0282	1.0468	0	0	0	0	0	0.0000%	
NEW SMYRNA BEACH (INT)	12,120	0	12,120	1.0000	0.0000	0.0000	1.0169	1.0282	1.0468	12,324	0	0	12,324	**20,395**	0.0166%	
QUINCY	152	0	152	1.0000	0.0000	0.0000	1.0169	1.0282	1.0468	155	0	0	155	155	0.0001%	
SEMINOLE (INT)	425,973	0	425,973	1.0000	0.0000	0.0000	1.0169	1.0282	1.0468	433,153	0	0	433,153	**679,849**	0.5523%	
WAUCHULA	92	0	92	1.0000	0.0000	0.0000	1.0169	1.0282	1.0468	94	0	0	94	94	0.0001%	
TOTAL WHOLESALE	5,787,865	(53,615)	5,734,251							5,830,911	0	0	5,830,911	6,157,587	5.0021%	
TOTAL FPL	117,600,745	(53,615)	117,547,131							7,684,256	2,771,031	112,318,213	122,773,500	123,100,177	100.0000%	
JURIS SEPARATION FACTOR															**0.949979**	

RATE CLASS	MWH SALES			VOLTAGE LEVEL %			LOSS EXPANSION FACTORS			MWH SALES @ GENERATION					% OF TOTAL	
	@ METER	ADJ	ADJUSTED	TRANS	PRIMARY	SECONDARY	TRANS	PRIMARY	SECOND	TRANS	PRIMARY	SECOND	TOTAL	ADJUSTED	SYSTEM	RETAIL

Contract Adjusted MWH Sales @ Generation -	Line No.	Source/Formula	FPUC (INT) Amount	HOMESTEAD (INT) Amount	NSB (INT) Amount	SEMINOLE (INT) Amount
1) Contract Wholesale Customer 12 CP	1	Load Forecast * Loss Factor	13,045	8,500	2,500	83,333
2) Intermediate System Capacity Net of Reserve Margin	2					
Intermediate Summer Capacity	3	2020-2029 TYSP	18,107,000	18,107,000	18,107,000	18,107,000
Divide By: System Capacity Including Reserve Margin (Calculation)	4		120.0%	120.0%	120.0%	120.0%
Intermediate System Capacity Net of Reserve Margin	5	L3 / L4	15,089,167	15,089,167	15,089,167	15,089,167
Contract Wholesale Customer Contribution to Intermediate System Capacity Net of Reserve Margin	6	L1 / L5	0.000865	0.000563	0.000166	0.005523
3) Contract Adjusted MWH Sales @ Generation	7					
Total System MWH Sales Excluding All Stratified Contracts	8		122,224,164	122,224,164	122,224,164	122,224,164
Contribution (Excluding Intermediate Stratified Contracts) to Other Production System Capacity Net of Reserve Margin	9	1 - Sum L6	0.99288	0.99288	0.99288	0.99288
Total System MWH Sales Including Intermediate Stratified Contracts	10	L8 / L9	123,100,177	123,100,177	123,100,177	123,100,177
Contract Adjusted MWH Sales @ Generation	11	L6 * L11	106,424	69,345	20,395	679,849

RATE CLASS	MWH SALES			VOLTAGE LEVEL %			LOSS EXPANSION FACTORS			MWH SALES @ GENERATION					% OF TOTAL	
	@ METER	ADJ	ADJUSTED	TRANS	PRIMARY	SECONDARY	TRANS	PRIMARY	SECOND	TRANS	PRIMARY	SECOND	TOTAL	ADJUSTED	SYSTEM	RETAIL
CILC-1D	2,635,788	0	2,635,788	0.0000	0.4148	0.5852	1.0169	1.0282	1.0468	0	1,124,208	1,614,572	2,738,780	2,738,780	2.2312%	2.3420%
CILC-1G	104,193	0	104,193	0.0000	0.0182	0.9818	1.0169	1.0282	1.0468	0	1,951	107,085	109,036	109,036	0.0888%	0.0932%
CILC-1T	1,470,591	0	1,470,591	1.0000	0.0000	0.0000	1.0169	1.0282	1.0468	1,495,380	0	0	1,495,380	1,495,380	1.2182%	1.2787%
GS(T)-1	6,506,169	0	6,506,169	0.0000	0.0000	1.0000	1.0169	1.0282	1.0468	0	0	6,810,760	6,810,760	6,810,760	5.5484%	5.8240%
GSCU-1	77,567	0	77,567	0.0000	0.0000	1.0000	1.0169	1.0282	1.0468	0	0	81,199	81,199	81,199	0.0661%	0.0694%
GSD(T)-1	27,339,373	0	27,339,373	0.0000	0.0032	0.9968	1.0169	1.0282	1.0468	0	91,279	28,526,352	28,617,631	28,617,631	23.3134%	24.4715%
GSLD(T)-1	10,202,111	0	10,202,111	0.0000	0.0343	0.9657	1.0169	1.0282	1.0468	0	359,942	10,313,256	10,673,197	10,673,197	8.6949%	9.1269%
GSLD(T)-2	2,700,592	0	2,700,592	0.0000	0.3964	0.6036	1.0169	1.0282	1.0468	0	1,100,605	1,706,441	2,807,046	2,807,046	2.2868%	2.4004%
GSLD(T)-3	259,243	0	259,243	1.0000	0.0000	0.0000	1.0169	1.0282	1.0468	263,612	0	0	263,612	263,612	0.2148%	0.2254%
MET	80,326	0	80,326	0.0000	1.0000	0.0000	1.0169	1.0282	1.0468	0	82,587	0	82,587	82,587	0.0673%	0.0706%
OL-1	92,432	0	92,432	0.0000	0.0000	1.0000	1.0169	1.0282	1.0468	0	0	96,759	96,759	96,759	0.0788%	0.0827%
OS-2	9,166	0	9,166	0.0000	1.0000	0.0000	1.0169	1.0282	1.0468	0	9,424	0	9,424	9,424	0.0077%	0.0081%
RS(T)-1	59,729,074	0	59,729,074	0.0000	0.0000	1.0000	1.0169	1.0282	1.0468	0	0	62,525,339	62,525,339	62,525,339	50.9364%	53.4667%
SL-1	474,786	0	474,786	0.0000	0.0000	1.0000	1.0169	1.0282	1.0468	0	0	497,013	497,013	497,013	0.4049%	0.4250%
SL-1M	8,734	0	8,734	0.0000	0.0000	1.0000	1.0169	1.0282	1.0468	0	0	9,143	9,143	9,143	0.0074%	0.0078%
SL-2	26,432	0	26,432	0.0000	0.0000	1.0000	1.0169	1.0282	1.0468	0	0	27,669	27,669	27,669	0.0225%	0.0237%
SL-2M	1,665	0	1,665	0.0000	0.0000	1.0000	1.0169	1.0282	1.0468	0	0	1,743	1,743	1,743	0.0014%	0.0015%
SST-DST	1,850	0	1,850	0.0000	0.5444	0.4556	1.0169	1.0282	1.0468	0	1,035	882	1,918	1,918	0.0016%	0.0016%
SST-TST	92,788	0	92,788	1.0000	0.0000	0.0000	1.0169	1.0282	1.0468	94,352	0	0	94,352	94,352	0.0769%	0.0807%
TOTAL RETAIL	111,812,880	0	111,812,880							1,853,345	2,771,031	112,318,213	116,942,590	116,942,590	95.2675%	100.0000%
FKEC	805,763	0	805,763	1.0000	0.0000	0.0000	1.0169	1.0282	1.0468	819,345	0	0	819,345	819,345	0.6675%	
FPUC (INT)	101,728	(101,728)	0	1.0000	0.0000	0.0000	1.0169	1.0282	1.0468	0	0	0	0	0	0.0000%	
FPUC (PEAK)	53,455	0	53,455	1.0000	0.0000	0.0000	1.0169	1.0282	1.0468	54,356	0	0	54,356	**396,101**	0.3227%	
HOMESTEAD	160	0	160	1.0000	0.0000	0.0000	1.0169	1.0282	1.0468	163	0	0	163	163	0.0001%	
HOMESTEAD (INT)	408	(408)	0	1.0000	0.0000	0.0000	1.0169	1.0282	1.0468	0	0	0	0	0	0.0000%	
LCEC	4,387,467	0	4,387,467	1.0000	0.0000	0.0000	1.0169	1.0282	1.0468	4,461,425	0	0	4,461,425	4,461,425	3.6345%	
MOORE HAVEN	28	0	28	1.0000	0.0000	0.0000	1.0169	1.0282	1.0468	28	0	0	28	28	0.0000%	
NEW SMYRNA BCH	360	0	360	1.0000	0.0000	0.0000	1.0169	1.0282	1.0468	366	0	0	366	366	0.0003%	
NEW SMYRNA BCH (PEAK)	160	0	160	1.0000	0.0000	0.0000	1.0169	1.0282	1.0468	163	0	0	163	**131,532**	0.1072%	
NEW SMYRNA BEACH (INT)	12,120	(12,120)	0	1.0000	0.0000	0.0000	1.0169	1.0282	1.0468	0	0	0	0	0	0.0000%	
QUINCY	152	0	152	1.0000	0.0000	0.0000	1.0169	1.0282	1.0468	155	0	0	155	155	0.0001%	
SEMINOLE (INT)	425,973	(425,973)	0	1.0000	0.0000	0.0000	1.0169	1.0282	1.0468	0	0	0	0	0	0.0000%	
WAUCHULA	92	0	92	1.0000	0.0000	0.0000	1.0169	1.0282	1.0468	94	0	0	94	94	0.0001%	
TOTAL WHOLESALE	5,787,865	(540,229)	5,247,636							5,336,093	0	0	5,336,093	5,809,207	4.7325%	
TOTAL FPL	117,600,745	(540,229)	117,060,516							7,189,438	2,771,031	112,318,213	122,278,683	122,751,797	100.0000%	
JURIS SEPARATION FACTOR															**0.952675**	

RATE CLASS	MWH SALES			VOLTAGE LEVEL %			LOSS EXPANSION FACTORS			MWH SALES @ GENERATION					% OF TOTAL	
	@ METER	ADJ	ADJUSTED	TRANS	PRIMARY	SECONDARY	TRANS	PRIMARY	SECOND	TRANS	PRIMARY	SECOND	TOTAL	ADJUSTED	SYSTEM	RETAIL

Contract Adjusted MWH Sales @ Generation -	Line No.	Source/Formula	FPUC (PEAK) Amount	NSB (PEAK) Amount
1) Contract Wholesale Customer 12 CP	1	Load Forecast * Loss Factor	10,038	3,333
2) Peaker System Capacity Net of Reserve Margin	2			
Peaker Summer Capacity	3	2020-2029 TYSP	3,733,000	3,733,000
Divide By: System Capacity Including Reserve Margin	4		120.0%	120.0%
Peaker System Capacity Net of Reserve Margin	5	L3 / L4	3,110,833	3,110,833
Contract Rate Class Contribution to Intermediate System Capacity Net of Reserve Margin	6	L1 / L5	0.003227	0.001072
3) Contract Adjusted MWH Sales @ Generation	7			
Total System MWH Sales @ Generation Excluding Peaker Stratified Contracts	8		122,224,164	122,224,164
Contribution (Excluding Peaker Stratified Contracts) to Other Production System Capacity Net of Reserve Margin	9	1 - Sum L6	0.99570	0.99570
Total System MWH Sales @ Generation Including Peaker Stratified Contracts	10	L8 / L9	122,751,797	122,751,797
Contract Adjusted 12CP @ Generation	11	L6 * L10	396,101	131,532

SEP - INTERNAL FACTORS BASED ON EXTERNAL FACTORS	ALLOCATOR(S)	COMPANY PER BOOKS	SEPARATION FACTOR	JURISDICTIONAL	INTERNAL SEPARATION FACTOR
I900-LABOR-EXC-A&G					
L_INC100000 - STEAM O&M PAY - OPERAT SUPERV & ENG	BLENDED	1,147,178.18	0.955397	1,096,010.93	
L_INC101210 - STEAM O&M PAY - FUEL - NON RECOVERABLE OIL	BLENDED	167,219.99	0.952802	159,327.48	
L_INC102000 - STEAM O&M PAY - STEAM EXPENSES	BLENDED	598,893.50	0.956249	572,691.59	
L_INC105000 - STEAM O&M PAY - ELECTRIC EXPENSES	BLENDED	478,249.34	0.954503	456,490.19	
L_INC106000 - STEAM O&M PAY - MISC STEAM POWER EXPENSES	BLENDED	5,761,012.02	0.953711	5,494,339.08	
L_INC110000 - STEAM O&M PAY - MAINT SUPERV & ENG	BLENDED	605,092.15	0.955914	578,415.90	
L_INC111000 - STEAM O&M PAY - MAINT OF STRUCTURES	BLENDED	1,319,446.70	0.953439	1,258,011.63	
L_INC112000 - STEAM O&M PAY - MAINT OF BOILER PLANT	BLENDED	1,922,239.13	0.955373	1,836,455.69	
L_INC113000 - STEAM O&M PAY - MAINT OF ELECTRIC PLANT	BLENDED	989,722.79	0.952962	943,168.49	
L_INC114000 - STEAM O&M PAY - MAINT OF MISC STEAM PLT	BLENDED	525,536.28	0.953780	501,246.12	
L_INC117000 - NUCLEAR O&M PAY - OPER SUPERV & ENG	E102NS	39,165,056.11	0.957097	37,484,775.04	
L_INC119000 - NUCLEAR O&M PAY - COOLANTS AND WATER	E102NS	4,386,699.37	0.956891	4,197,592.18	
L_INC120000 - NUCLEAR O&M PAY - STEAM EXPENSES	E102NS	44,137,818.52	0.956891	42,235,071.66	
L_INC123000 - NUCLEAR O&M PAY - ELECTRIC EXP	E102NS	376.85	0.956891	360.60	
L_INC124000 - NUCLEAR O&M PAY - MISC NUCLEAR POWER EXP	E102NS	34,409,745.69	0.956891	32,926,368.44	
L_INC128000 - NUCLEAR O&M PAY - MAINT SUPERVISION & ENGINEERING	E202NS	39,200,661.09	0.956788	37,506,714.34	
L_INC129000 - NUCLEAR O&M PAY - MAINT OF STRUCTURES	E102NS	48,658.53	0.956891	46,560.90	
L_INC130000 - NUCLEAR O&M PAY - MAINT OF REACTOR PLANT	E201	132,730.24	0.956788	126,994.68	
L_INC131000 - NUCLEAR O&M PAY - MAINT OF ELECTRIC PLANT	E201	740,043.79	0.956877	708,131.00	
L_INC132000 - NUCLEAR O&M PAY - MAINT OF MISC NUCLEAR PLANT	E201	5,759.69	0.956788	5,510.80	
L_INC146000 - OTH PWR O&M PAY - OPERAT SUPERV & ENG	BLENDED	12,409,546.18	0.951193	11,803,876.11	
L_INC147200 - OTH PWR O&M PAY - FUEL N- RECOV EMISSIONS FEE	E203INT	3,151,294.58	0.952021	3,000,097.40	
L_INC148000 - OTH PWR O&M PAY- GENERATION EXPENSES	BLENDED	8,873,470.21	0.950224	8,431,788.00	
L_INC149000 - OTH PWR O&M PAY - MISC OTHER POWER GENERATION EXPEN	BLENDED	16,351,473.57	0.950649	15,544,510.77	
L_INC151000 - OTH PWR O&M PAY - MAINT SUPERV & ENG	BLENDED	5,687,089.80	0.950794	5,407,253.26	
L_INC152000 - OTH PWR O&M PAY - MAINT OF STRUCTURES	BLENDED	5,975,427.19	0.950201	5,677,856.48	
L_INC153000 - OTH PWR O&M PAY - MAINT GENERATING & ELECTRIC PLANT	BLENDED	20,934,011.09	0.950258	19,892,712.79	
L_INC154000 - OTH PWR O&M PAY - MAINT MISC OTHER PWR GENERAT	BLENDED	3,782,572.64	0.950257	3,594,416.03	
L_INC156000 - OTH PWR O&M PAY - SYSTEM CONTROL & LOAD DISPATCH	E103INT	808,421.13	0.950081	768,065.80	
L_INC157000 - OTH PWR O&M PAY - OTHER EXPENSES LOC 955	E103INT	1,811,998.86	0.950081	1,721,546.24	
L_INC260010 - TRANS O&M PAY - OPERATION SUPERV & ENGINEERING	E101	4,731,091.68	0.902300	4,268,863.39	
L_INC261000 - TRANS O&M PAY - LOAD DISPATCHING	E101	2,919,935.27	0.902300	2,634,657.20	
L_INC262000 - TRANS O&M PAY - STATION EXPENSES	E101	268,504.32	0.902300	242,271.41	
L_INC263000 - TRANS O&M PAY - OVERHEAD LINE EXPENSES	E101	64,220.91	0.902300	57,946.51	
L_INC266000 - TRANS O&M PAY - MISC TRANSMISSION EXPENSES	E101	2,919,880.82	0.902300	2,634,608.08	
L_INC267000 - TRANS O&M - RENTS	E101				
L_INC268010 - TRANS O&M PAY - MAINT SUPERV & ENG	E101	903,249.89	0.902300	815,002.26	
L_INC269000 - TRANS O&M PAY - MAINT OF STRUCTURES	E101	2,345,258.74	0.902300	2,116,126.65	
L_INC270000 - TRANS O&M PAY - MAINT OF STATION EQ	E101	1,629,500.36	0.902300	1,470,297.96	
L_INC271000 - TRANS O&M PAY - MAINT OF OVERHEAD LINES	E101	1,387,714.48	0.902300	1,252,134.59	
L_INC272000 - TRANS O&M PAY - MAINT UNDERGROUND LINES	E101	18,562.68	0.902300	16,749.10	
L_INC273000 - TRANS O&M PAY - MAINT OF MISC TRANS PLANT	E101				
L_INC380000 - DIST O&M PAY - OPERATION SUPERVISION AND ENGINEERING	E104	11,618,950.51	1.000000	11,618,950.51	
L_INC381000 - DIST O&M PAY - LOAD DISPATCHING	E104				
L_INC382000 - DIST O&M PAY - SUBSTATION EXPENSES	E104	616,954.80	1.000000	616,954.80	
L_INC383000 - DIST O&M PAY - OVERHEAD LINE EXPENSES	I365T	3,608,330.73	1.000000	3,608,330.73	
L_INC384000 - DIST O&M PAY - UNDERGROUND LINE EXP	I367T	1,332,549.90	1.000000	1,332,549.90	
L_INC385000 - DIST O&M PAY - STREET LIGHTING AND SIGNAL SYSTEM EXPEN	E508	185,707.33	1.000000	185,707.33	
L_INC386000 - DIST O&M PAY - METER EXPENSES	E325	9,015,012.38	0.996099	8,979,847.56	
L_INC387000 - DIST O&M PAY - CUSTOMER INSTALLATIONS EXP	E309	728,886.16	1.000000	728,886.16	
L_INC388000 - DIST O&M PAY - MISC DISTRIBUTION EXPENSES	E104	28,506,232.92	1.000000	28,506,232.92	
L_INC389000 - DIST O&M - RENTS	E104				
L_INC390000 - DIST O&M PAY - MAINT SUPERV & ENG	E104	15,849,141.15	1.000000	15,849,141.15	
L_INC391000 - DIST O&M PAY - MAINT OF STRUCTURES	E104	29,858.01	1.000000	29,858.01	
L_INC392000 - DIST O&M PAY - MAINT OF STATION EQ	E104	2,689,213.41	1.000000	2,689,213.41	
L_INC393000 - DIST O&M PAY - MAINT OF OVERHEAD LINES	I365T	25,504,837.31	1.000000	25,504,837.31	
L_INC394000 - DIST O&M PAY - MAINT UNDERGROUND LINES	I367T	11,391,291.41	1.000000	11,391,291.41	
L_INC395000 - DIST O&M PAY - MAINT OF LINE TRANSFORMERS	E104	24,345.33	1.000000	24,345.33	
L_INC396000 - DIST O&M PAY - MAINT OF STREET LIGHTING & SIGNAL SYSTEM	E508	4,222,133.97	1.000000	4,222,133.97	
L_INC397000 - DIST O&M PAY - MAINT OF METERS	E325	2,737,925.21	0.996099	2,727,245.39	
L_INC398000 - DIST O&M PAY - MAINT OF MISC DISTRI PLT	E104	617,369.49	1.000000	617,369.49	
L_INC401000 - CUST ACCT O&M PAY - SUPERVISION	I540	5,049,612.81	0.999993	5,049,576.33	
L_INC402000 - CUST ACCT O&M PAY - METER READING EXP	E330	3,360,791.16	0.999656	3,359,635.75	
L_INC403000 - CUST ACCT O&M PAY - CUST REC & COLLECT	E356	33,500,296.35	1.000000	33,500,296.35	
L_INC404000 - CUST ACCT EXP - UNCOLLECTIBLE ACCOUNTS	E205				
L_INC405000 - CUST ACCT O&M PAY - MISC CUSTOMER ACCOUNTS EXPENSES	E355				
L_INC407000 - CUST SERV & INFO PAY - SUPERVISION	E356	550,288.21	1.000000	550,288.21	
L_INC408000 - CUST SERV & INFO PAY - CUST ASSIST EXP	E356	1,692,901.63	1.000000	1,692,901.63	

SEP - INTERNAL FACTORS BASED ON EXTERNAL FACTORS	ALLOCATOR(S)	COMPANY PER BOOKS	SEPARATION FACTOR	JURISDICTIONAL	INTERNAL SEPARATION FACTOR
L_INC409000 - CUST SERV & INFO PAY - INFO & INST ADV - GENERAL	E355				
L_INC410000 - CUST SERV & INFO PAY - MISC CUST SERV & INF	E356	4,778,271.44	1.000000	4,778,271.44	
L_INC411000 - SUPERVISION-SALES EXPENSES	E356				
L_INC510000 - DEMONSTRATING AND SELLING EXPENSES	E356				
L_INC516000 - MISC AND SELLING EXPENSES	E356	603,279.45	1.000000	603,279.45	
Total I900-LABOR-EXC-A&G		440,929,545.43		427,652,161.32	**0.969888**

CONFIDENTIAL

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20200001-EI EXHIBIT: 17
PARTY: FLORIDA POWER & LIGHT COMPANY – DIRECT
DESCRIPTION: G.J. Yupp GJY-1

APPENDIX I

FUEL COST RECOVERY

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20200001-EI   EXHIBIT: 18
PARTY: FLORIDA POWER & LIGHT COMPANY – DIRECT
DESCRIPTION: G.J. Yupp GJY-2

EXHIBIT GJY-2

DOCKET NO. 20200001-EI

PAGES 1-4

SEPTEMBER 3, 2020

APPENDIX I

FUEL COST RECOVERY

TABLE OF CONTENTS

PAGE	DESCRIPTION	SPONSOR
3	Projected Dispatch Costs	G. Yupp
3	Projected Availability of Natural Gas	G. Yupp
4	Projected Unit Availabilities and Outage Schedules	G. Yupp

Florida Power and Light Company

Projected Dispatch Costs and Projected Availability of Natural Gas

January 2021 Through December 2021

Heavy Oil	January	February	March	April	May	June	July	August	September	October	November	December
0.7% Sulfur Grade ($/Bbl)	55.25	55.60	55.90	56.20	56.50	56.80	57.05	57.30	57.55	57.80	58.05	58.30
0.7% Sulfur Grade ($/MMBtu)	8.63	8.69	8.73	8.78	8.83	8.88	8.91	8.95	8.99	9.03	9.07	9.11

Light Oil	January	February	March	April	May	June	July	August	September	October	November	December
Ultra-Low Sulfur Distillate ($/Bbl)	58.48	58.94	59.18	59.19	59.35	59.61	60.12	60.61	61.03	61.44	61.83	62.18
Ultra-Low Sulfur Distillate ($/MMBtu)	10.03	10.11	10.15	10.15	10.18	10.22	10.31	10.40	10.47	10.54	10.61	10.66

Natural Gas Transportation	January	February	March	April	May	June	July	August	September	October	November	December
Firm FGT (MMBtu/Day)	1,150,000	1,150,000	1,150,000	1,239,000	1,274,000	1,274,000	1,274,000	1,274,000	1,274,000	1,239,000	1,150,000	1,150,000
Firm Gulfstream (MMBtu/Day)	695,000	695,000	695,000	695,000	695,000	695,000	695,000	695,000	695,000	695,000	695,000	695,000
Sabal Trail/FSC (MMBtu/Day)	600,000	600,000	600,000	600,000	600,000	600,000	600,000	600,000	600,000	600,000	600,000	600,000
Non-Firm FGT (MMBtu/Day)	100,000	100,000	100,000	100,000	75,000	50,000	50,000	50,000	50,000	75,000	100,000	100,000
Non-Firm Gulfstream (MMBtu/Day)	50,000	50,000	50,000	50,000	50,000	50,000	-	-	-	-	50,000	50,000
Total Projected Daily Availability (MMBtu/Day)	2,595,000	2,595,000	2,595,000	2,684,000	2,694,000	2,669,000	2,619,000	2,619,000	2,619,000	2,609,000	2,595,000	2,595,000
Southeast Supply Header (SESH)**	80,000	80,000	80,000	80,000	80,000	80,000	80,000	80,000	80,000	80,000	80,000	80,000
Transcontinental Pipe Line (Transco)**	196,500	196,500	196,500	196,500	196,500	196,500	196,500	196,500	196,500	196,500	121,500	121,500
Gulf South Pipeline Company (Gulf South)**	319,000	319,000	319,000	464,000	464,000	464,000	464,000	464,000	464,000	464,000	299,000	299,000

**Note: SESH,Transco and Gulf South firm transportation does not provide increased capacity to FPL's plants but does increase FPL's access to on-shore supply.

Natural Gas Dispatch Price	January	February	March	April	May	June	July	August	September	October	November	December
Firm FGT ($/MMBtu)	2.99	2.96	2.86	2.58	2.56	2.59	2.66	2.68	2.64	2.64	2.70	2.83
Firm Gulfstream ($/MMBtu)	2.92	2.90	2.79	2.45	2.47	2.49	2.55	2.57	2.52	2.51	2.63	2.76
Firm Sabal Trail/FSC ($/MMBtu)	2.94	2.89	2.78	2.49	2.47	2.50	2.56	2.59	2.56	2.57	2.63	2.79
Non-Firm FGT ($/MMBtu)	3.99	3.97	3.87	3.59	3.57	3.60	3.68	3.71	3.67	3.66	3.71	3.83
Non-Firm Gulfstream ($/MMBtu)	3.82	3.80	3.70	3.42	3.40	3.44	3.51	3.54	3.50	3.50	3.54	3.66

Coal	January	February	March	April	May	June	July	August	September	October	November	December
Scherer ($/MMBtu)	2.52	2.53	2.53	2.52	2.51	2.52	2.55	2.56	2.55	2.55	2.56	2.57

FLORIDA POWER & LIGHT
PROJECTED UNIT AVAILABILITIES & OUTAGE SCHEDULES
PERIOD OF: JANUARY 2021 THROUGH DECEMBER 2021

Plant/Unit	Forced Outage Factor (%)	Maintenance Outage Factor (%)	Planned Outage Factor (%)	Overhaul Date	Overhaul Date	Overhaul Date	Overhaul Date	Overhaul Date
Cape Canaveral 3	1.1	5.5	2.7	02/16/21 - 02/25/21	11/15/21 - 11/24/21	11/29/21 - 12/08/21		
Ft. Myers 2	0.7	5.5	3.2	02/27/21 - 03/05/21	10/23/21 - 10/29/21	10/31/21 - 11/13/21	11/07/21 - 11/13/21	11/15/21 - 11/21/21
Ft. Myers 3A	0.8	5.5	1.9	02/08/21 - 02/14/21				
Ft. Myers 3B	0.8	5.5	1.9	02/08/21 - 02/14/21				
Ft. Myers 3C	0.8	5.5	1.9	02/12/21 - 02/18/21				
Ft. Myers 3D	0.8	5.5	1.9	02/12/21 - 02/18/21				
Lauderdale 6A	0.5	5.5	3.8	02/08/21 - 02/21/21				
Lauderdale 6B	0.5	5.5	1.9	01/18/21 - 01/24/21				
Lauderdale 6C	0.5	5.5	1.9	02/22/21 - 02/28/21				
Lauderdale 6D	0.5	5.5	1.9	01/25/21 - 01/31/21				
Lauderdale 6E	0.5	5.5	1.9	02/01/21 - 02/07/21				
Manatee 1	0.3	4.6	19.5	02/15/21 - 02/24/21				
Manatee 2	0.3	4.6	19.5	02/01/21 - 02/10/21				
Manatee 3	0.6	5.5	1.9	10/15/21 - 10/21/21				
Martin 3	0.6	5.5	0.0	NONE				
Martin 4	0.5	4.6	19.2	04/24/21 - 07/02/21				
Martin 8	1.0	5.5	3.6	02/22/21 - 03/06/21	03/07/21 - 03/19/21	03/20/21 - 04/01/21	04/02/21 - 04/14/21	
Okeechobee 1	1.5	5.5	8.0	02/16/21 - 03/07/21	10/15/21 - 11/11/21	02/16/21 - 03/07/21		
Port Everglades 5	1.5	5.5	5.5	03/22/21 - 04/10/21				
Riviera 5	1.1	5.5	7.7	04/03/21 - 04/30/21				
Sanford 4	0.4	5.5	3.8	03/06/21 - 03/19/21				
Sanford 5	0.4	5.5	3.8	03/20/21 - 04/02/21				
Scherer 4	2.3	5.5	0.0	NONE				
St. Lucie 1	1.1	1.1	9.3	04/10/21 - 05/14/21				
St. Lucie 2	1.1	1.1	9.6	08/28/21 - 10/02/21				
Turkey Point 3	1.2	1.2	7.9	10/09/21 - 11/07/21				
Turkey Point 4	1.3	1.3	0.0	NONE				
Turkey Point 5	0.6	5.5	10.9	03/01/21 - 03/21/21	11/09/21 - 11/21/21	11/12/21 - 11/24/21	11/29/21 - 12/08/21	12/02/21 - 12/14/21
West County 1	0.8	5.5	2.7	10/01/21 - 10/10/21				
West County 2	0.8	5.5	2.7	03/08/21 - 03/17/21				
West County 3	0.8	5.5	9.1	02/15/21 - 04/05/21	10/26/21 - 12/14/21			

GENERATING PERFORMANCE INCENTIVE FACTOR

JANUARY THROUGH DECEMBER, 2019

CRR-1
DOCKET NO. 20200001-EI
FPL Witness: Charles R. Rote
Exhibit No.: ____________________
Pages 1 - 20
March 16, 2020

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20200001-EI EXHIBIT: 19
PARTY: FLORIDA POWER & LIGHT COMPANY – DIRECT
DESCRIPTION: C.R. Rote CRR-1

FLORIDA POWER & LIGHT COMPANY

JANUARY THROUGH DECEMBER, 2019

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6.203.001	Index of Manual Pages
6.203.002	GPIF Reward/(Penalty) Table (Actual)
6.203.003	GPIF Calculation of Maximum Allowed Incentive Dollars (Actual)
6.203.004	Derivation of System Actual GPIF Points
6.203.005	Actual Equivalent Availability and Adjustments Summary
6.203.006	EAF Adjustment Documentation
6.203.007	Adjustments to Average Net Operating Heat Rates and Adjustments Summary
6.203.008 - 6.203.019	GPIF Units Points Tables
6.203.020	Planned Outages Schedule (Actual)

GENERATING PERFORMANCE INCENTIVE FACTOR

REWARD/PENALTY TABLE (ACTUAL)

FLORIDA POWER & LIGHT COMPANY
JANUARY THROUGH DECEMBER, 2019

GENERATNG PERFORMANCE INCENTIVE POINTS (GPIF)		FUEL SAVINGS/(LOSS) ($000)		GENERATING PERFORMANCE INCENTIVE FACTOR ($000)	
+ 10		47,637		23,819	
+ 9		42,873		21,437	
+ 8		38,110		19,055	
+ 7		33,346		16,673	
+ 6		28,582		14,291	
+ 5		23,819		11,909	
+ 4		19,055		9,527	
+ 3	<--------- 3.4115	14,291	<--------- 16,250.444	7,146	<-------- 8,125.681
+ 2		9,527		4,764	
+ 1		4,764		2,382	
0		0		0	
- 1		(4,764)		(2,382)	
- 2		(9,527)		(4,764)	
- 3		(14,291)		(7,146)	
- 4		(19,055)		(9,527)	
- 5		(23,819)		(11,909)	
- 6		(28,582)		(14,291)	
- 7		(33,346)		(16,673)	
- 8		(38,110)		(19,055)	
- 9		(42,873)		(21,437)	
- 10		(47,637)		(23,819)	

GENERATING PERFORMANCE INCENTIVE FACTOR

CALCULATION OF MAXIMUM ALLOWED INCENTIVE DOLLARS

ACTUAL

FLORIDA POWER & LIGHT COMPANY
JANUARY THROUGH DECEMBER, 2019

LINE 1	BEGINNING OF PERIOD BALANCE OF COMMON EQUITY END OF MONTH BALANCE OF COMMON EQUITY		$ 20,429,221,803	
LINE 2	MONTH OF January	2019	$ 20,899,236,128	
LINE 3	MONTH OF February	2019	$ 21,064,627,157	
LINE 4	MONTH OF March	2019	$ 21,262,348,902	
LINE 5	MONTH OF April	2019	$ 21,452,596,443	
LINE 6	MONTH OF May	2019	$ 21,673,984,533	
LINE 7	MONTH OF June	2019	$ 20,522,901,172	
LINE 8	MONTH OF July	2019	$ 20,792,963,296	
LINE 9	MONTH OF August	2019	$ 21,049,754,959	
LINE 10	MONTH OF September	2019	$ 20,443,211,939	
LINE 11	MONTH OF October	2019	$ 20,605,370,574	
LINE 12	MONTH OF November	2019	$ 20,804,773,224	
LINE 13	MONTH OF December	2019	$ 20,848,759,623	
LINE 14	AVERAGE COMMON EQUITY FOR THE PERIOD (SUMMATION OF LINE1 THROUGH LINE 13 DIVIDED BY 13)		$ 20,911,519,212	
LINE 15	25 BASIS POINTS		0.0025	
LINE 16	REVENUE EXPANSION FACTOR		74.6012%	
LINE 17	MAXIMUM ALLOWED INCENTIVE DOLLARS (LINE 14 TIMES LINE 15 DIVIDED BY LINE 16)		$ 70,077,645	
LINE 18	JURISDICTIONAL SALES		111,929,429,000	KWH
LINE 19	TOTAL SALES		119,244,153,891	KWH
LINE 20	JURISDICTIONAL SEPARATION FACTOR (LINE 18 DIVIDED BY LINE 19)		93.87%	
LINE 21	MAXIMUM ALLOWED JURISDICTIONAL INCENTIVE DOLLARS (LINE 17 TIMES LINE 20)		$ 65,781,885	
LINE 22	INCENTIVE CAP (50 PERCENT OF PROJECTED FUEL SAVINGS AT 10 GPIF·POINT LEVEL FROM SHEET NO. 3.515)		$ 23,818,500	
LINE 23	MAXIMUM ALLOWED GPIF REWARD (AT 10 GPIF-POINT LEVEL) (THE LESSER OF LINE 21 AND LINE 22)		$ 23,818,500	

Note: Line 22 and 23 are as approved by Commission order PSC-13-0665-FOF-EI dated 12/18/13 effective 1/1/14.

JANUARY THROUGH DECEMBER, 2019

DERIVATION OF SYSTEM ACTUAL GPIF POINTS

PLANT/UNIT	PERFORMANCE INDICATOR	WEIGHTING FACTOR %	UNIT POINTS	WEIGHTED UNIT POINTS
Cape Canaveral 3	EAF	2.89	10.00	.2890
Cape Canaveral 3	ANOHR	4.79	0.00	.0000
Manatee 3	EAF	2.19	1.60	.0350
Manatee 3	ANOHR	4.22	0.00	.0000
Ft. Myers 2	EAF	2.51	3.20	.0803
Ft. Myers 2	ANOHR	6.41	-10.00	-.6410
Martin 8	EAF	2.20	3.60	.0792
Martin 8	ANOHR	4.80	0.00	.0000
Riviera 5	EAF	2.67	2.80	.0748
Riviera 5	ANOHR	3.90	8.89	.3467
St. Lucie 1	EAF	8.73	-10.00	-.8730
St. Lucie 1	ANOHR	0.82	0.00	.0000
St. Lucie 2	EAF	8.08	10.00	.8080
St. Lucie 2	ANOHR	0.72	0.00	.0000
Turkey Point 3	EAF	7.55	10.00	.7550
Turkey Point 3	ANOHR	1.41	10.00	.1410
Turkey Point 4	EAF	6.85	10.00	.6850
Turkey Point 4	ANOHR	1.28	0.00	.0000
West County 1	EAF	4.01	-5.00	-.2005
West County 1	ANOHR	5.65	0.00	.0000
West County 2	EAF	2.49	10.00	.2490
West County 2	ANOHR	5.51	10.00	.5510
West County 3	EAF	4.14	10.00	.4140
West County 3	ANOHR	6.18	10.00	.6180
		-------------		--------------
GPIF System Total:		100.00		3.4115

ACTUAL EQUIVALENT AVAILABILITY AND ADJUSTMENTS

JANUARY THROUGH DECEMBER, 2019

1	2	3	4	5	6	7	8	9			
	ACTUAL				PLANNED OUTAGE ADJ TO EAF (1)	ADJUSTED ACTUAL EAF	TARGET EAF	POINTS FROM TABLES	ORIGINAL PLANNED OUTAGE DATES	ACTUAL OUTAGE DATES	ACTUAL FUEL SAVINGS/ (LOSS) ($000)
UNIT	FOF	MOF	POF	EAF							
Cape Canaveral 3	0.5	4.6	7.2	87.7	-6.5	81.2	77.7	10.00	03/10/19 - 04/06/19; 04/26/19 - 05/09/19 05/10/19 - 06/06/19	7/15/19-8/24/19 11/05/19-12/15/19	1,375.0
Manatee 3	0.4	5.3	0.0	94.3	-2.7	91.6	91.2	1.60	01/16/19 - 01/21/19;	NONE	167.0
Ft. Myers 2	0.6	3.5	18.8	77.1	5.2	82.3	81.5	3.20	01/04/19 - 03/04/19; 01/25/19 - 03/20/19 03/04/19 - 05/04/19; 03/26/19 - 05/19/19	1/8/19-6/12/19; 6/19/19-6/19/19 1/8/19-1/16/19; 3/12/19-6/12/19 11/14/19-12/13/19; 11/4/19-12/14/19 1/1/19-1/4/19; 1/6/19-2/18/19	382.4
Martin 8	0.2	5.5	0.0	94.2	-2.5	91.7	90.8	3.60	10/03/19 - 10/09/19; 10/10/19 - 10/16/19	NONE	376.9
Riviera 5	0.5	6.3	4.1	89.1	-1.7	87.4	86.7	2.80	02/16/19 - 04/01/19;	2/15/19-4/5/19	355.6
St. Lucie 1	20.3	0.0	9.6	70.1	1.1	71.2	84.6	-10.00	09/02/19 - 10/02/19	10/12/19-11/20/19	(4,157.0)
St. Lucie 2	0.0	0.0	0.0	100.0	0.0	100.0	93.6	10.00	NONE	9/26/19	3,848.0
Turkey Point 3	0.9	0.0	0.0	99.1	0.0	99.1	93.6	10.00	NONE	NONE	3,597.0
Turkey Point 4	0.1	0.0	9.3	90.6	-3.0	87.6	81.3	10.00	03/11/19 - 04/25/19	3/8/19-4/15/19	3,263.0
West County 1	0.9	9.2	0.0	89.9	-4.0	85.9	87.4	-5.00	11/15/19 - 11/30/19;	NONE	(956.5)
West County 2	0.9	1.7	12.0	85.4	3.6	89.0	84.5	10.00	10/17/19 - 11/16/19; 10/17/19 - 12/19/19 10/24/19 - 11/23/19; 10/31/19 - 11/30/19	3/30/19-5/13/19; 4/2/19-5/16/19 4/6/19-5/19/19	1,186.0
West County 3	0.6	7.1	0.0	92.3	-4.1	88.2	86.8	10.00	02/20/19 - 03/07/19; 11/18/19 - 12/03/19 11/21/19 - 12/06/19	NONE	1,972.0
											11,409.460

(1) EQUIVALENT AVAILABILITY ADJUSTMENT DUE TO PLANNED OUTAGE ACTUAL DURATION VERSUS TARGET DURATION
SEE 6.203.006 FOR FORMULAS AND CALCULATION DATA

EQUIVALENT AVAILABILITY ADJUSTMENTS
JANUARY THROUGH DECEMBER, 2019

	ACTUAL				TARGETS		ADJUSTED ACTUAL
PLANT / UNIT	PH	EFOH	EMOH	EPOH	POF%	EPOH	EAF%
Cape Canaveral 3	8760	43.0	400.0	634.3	14.1	1232.0	81.2
Manatee 3	8760	33.3	466.4	0.0	2.9	252.0	91.6
Ft. Myers 2	8760	56.0	302.8	1644.5	13.3	1166.6	82.3
Martin 8	8760	18.6	485.2	0.0	2.7	240.0	91.7
Riviera 5	8760	45.6	552.7	357.0	5.9	520.0	87.4
St. Lucie 1	8760	1777.6	0.0	843.2	8.2	720.0	71.2
St. Lucie 2	8760	0.0	0.0	0.7	0.0	0.0	100.0
Turkey Point 3	8760	74.9	0.0	0.0	0.0	0.0	99.1
Turkey Point 4	8760	10.0	0.0	815.5	12.3	1080.0	87.6
West County 1	8760	80.0	808.8	0.0	4.4	384.0	85.9
West County 2	8760	80.7	152.1	1050.5	8.2	720.0	89.0
West County 3	8760	53.9	624.1	0.0	4.4	384.0	88.2

$$\text{ADJ. ACTUAL EAF\%} = 100\% - POF_T - \frac{(EFOH_A + EMOH_A) \times \dfrac{PH - EPOH_T}{PH - EPOH_A}}{PH} \times 100\%$$

ADJUSTMENTS TO AVERAGE NET OPERATING HEAT RATES & ADJUSTMENTS SUMMARY

JANUARY THROUGH DECEMBER, 2019

1	2	3	4	5	6	7	8	9	
		ACTUAL		TARGET (2) ANOHR AT ACTUAL NOF	ADJUST.(3) TO ANOHR	TARGET (4) ANOHR	ADJUST.(5) ACTUAL ANOHR	GPIF(6) POINTS FROM TABLE	ACTUAL FUEL SAV./(LOSS)
UNIT	HEAT RATE (1) FORMULA	NOF %	ANOHR BTU/KWH	BTU/KWH	BTU/KWH	BTU/KWH	BTU/KWH		$000
Cape Canaveral 3	ANOHR= -1.04 x NOF + 6,711	58.8	6,632	6,650	-18	6,644	6,626	0.00	0.0
Manatee 3	ANOHR= -1.25 x NOF + 6,998	75.2	6,897	6,904	-7	6,924	6,917	0.00	0.0
Ft. Myers 2	ANOHR= -4.66 x NOF + 7,538	57.0	7,588	7,272	316	7,298	7,614	-10.00	(3052.0)
Martin 8	ANOHR= -1.49 x NOF + 7,068	70.2	6,938	6,963	-25	6,977	6,952	0.00	0.0
Riviera 5	ANOHR= -4.33 x NOF + 6,949	58.5	6,605	6,696	-91	6,661	6,570	8.89	1650.0
St. Lucie 1	ANOHR= -28.84 x NOF + 13,242	101.0	10,322	10,329	-7	10,404	10,397	0.00	0.0
St. Lucie 2	ANOHR= -20.69 x NOF + 12,306	102.7	10,161	10,181	-20	10,268	10,248	0.00	0.0
Turkey Point 3	ANOHR= -46.05 x NOF + 15,575	103.2	10,396	10,823	-427	11,021	10,594	10.00	674.0
Turkey Point 4	ANOHR= -48.13 x NOF + 15,685	100.5	10,836	10,848	-12	10,954	10,942	0.00	0.0
West County 1	ANOHR= -8.05 x NOF + 7,653	69.3	7,093	7,095	-2	7,012	7,010	0.00	0.0
West County 2	ANOHR= -8.67 x NOF + 7,636	71.1	6,861	7,020	-159	6,946	6,787	10.00	2626.0
West County 3	ANOHR= -3.13 x NOF + 7,245	70.2	6,873	7,025	-152	6,982	6,830	10.00	2943.0
									4,840.984

1) THESE FORMULAS ARE AS APPROVED BY THE COMMISSION IN THE PROJECTION FILING AND ARE BASED ON MONTHLY ACTUAL DATA
2) CALCULATED FROM ANOHR FORMULA IN COLUMN 2 USING ACTUAL NOF IN COLUMN 3
3) ADJUSTMENT TO ANOHR=ACTUAL ANOHR - TARGET ANOHR AT ACTUAL NOF (COLUMN 6 = COLUMN 4 - COLUMN 5).
4) AT TARGET NOF AS APPROVED BY THE COMMISSION IN PROJECTED DATA.
5) AT TARGET NOF, ADJUSTED ACTUAL ANOHR = TARGET ANOHR + ADJUSTMENTS (COLUMN 8 = COLUMN 7 + COLUMN 6).
6) OBTAINED FROM THE GPIF POINT TABLES USING THE COMMISSION APPROVED TARGETS.

GENERATING PERFORMANCE INCENTIVE POINTS TABLES
FLORIDA POWER & LIGHT COMPANY
PERIOD OF JANUARY THROUGH DECEMBER, 2019

UNIT: Cape Canaveral 3

EQUIVALENT AVAILABILITY POINTS	FUEL SAVINGS/(LOSS) ($000)	ADJUSTED ACTUAL EQUIVALENT AVAILABILITY	AVERAGE HEAT RATE POINTS	FUEL SAVING/(LOSS) ($000)	ADJUSTED ACTUAL AVG. HEAT RATES
+10	1,375.0 <- Fuel Sav/(Loss) 1.375.0	80.7 <- Adj. Act. EAF= 81.2	+10	2,283.0	6,517
+9	1,237.5	80.4	+9	2,054.7	6,522
+8	1,100.0	80.1	+8	1,826.4	6,527
+7	962.5	79.8	+7	1,598.1	6,533
+6	825.0	79.5	+6	1,369.8	6,538
+5	687.5	79.2	+5	1,141.5	6,543
+4	550.0	78.9	+4	913.2	6,548
+3	412.5	78.6	+3	684.9	6,553
+2	275.0	78.3	+2	456.6	6,559
+1	137.5	78.0	+1	228.3	6,564
				0 <- Fuel Sav/(Loss)	6,569 <- Adj. Act. HR=6,626
0	0	77.7	0	0	6,644
				0	6,719
-1	(137.5)	77.4	-1	(228.3)	6,724
-2	(275.0)	77.1	-2	(456.6)	6,729
-3	(412.5)	76.8	-3	(684.9)	6,735
-4	(550.0)	76.5	-4	(913.2)	6,740
-5	(687.5)	76.2	-5	(1,141.5)	6,745
-6	(825.0)	75.9	-6	(1,369.8)	6,750
-7	(962.5)	75.6	-7	(1,598.1)	6,755
-8	(1,100.0)	75.3	-8	(1,826.4)	6,761
-9	(1,237.5)	75.0	-9	(2,054.7)	6,766
-10	(1,375.0)	74.7	-10	(2,283.0)	6,771

WEIGHTING FACTOR = 2.89

WEIGHTING FACTOR = 4.79

GENERATING PERFORMANCE INCENTIVE POINTS TABLES
FLORIDA POWER & LIGHT COMPANY
PERIOD OF JANUARY THROUGH DECEMBER, 2019

UNIT: Manatee 3

EQUIVALENT AVAILABILITY POINTS	FUEL SAVINGS/(LOSS) ($000)	ADJUSTED ACTUAL EQUIVALENT AVAILABILITY	AVERAGE HEAT RATE POINTS	FUEL SAVING/(LOSS) ($000)	ADJUSTED ACTUAL AVG. HEAT RATES
+10	1,044.0	93.7	+10	2,010.0	6,790
+9	939.6	93.5	+9	1,809.0	6,796
+8	835.2	93.2	+8	1,608.0	6,802
+7	730.8	93.0	+7	1,407.0	6,808
+6	626.4	92.7	+6	1,206.0	6,814
+5	522.0	92.5	+5	1,005.0	6,820
+4	417.6	92.2	+4	804.0	6,825
+3	313.2	92.0	+3	603.0	6,831
+2	208.8	91.7	+2	402.0	6,837
+1	104.4 <- Fuel Sav/(Loss)	91.5 <- Adj. Act. EAF= 91.6	+1	201.0	6,843
				0 <- Fuel Sav/(Loss)	6,849 <- Adj. Act. HR=6,917
0	0	91.2	0	0	6,924
				0	6,999
-1	(104.4)	91.0	-1	(201.0)	7,005
-2	(208.8)	90.7	-2	(402.0)	7,011
-3	(313.2)	90.5	-3	(603.0)	7,017
-4	(417.6)	90.2	-4	(804.0)	7,023
-5	(522.0)	90.0	-5	(1,005.0)	7,029
-6	(626.4)	89.7	-6	(1,206.0)	7,034
-7	(730.8)	89.5	-7	(1,407.0)	7,040
-8	(835.2)	89.2	-8	(1,608.0)	7,046
-9	(939.6)	89.0	-9	(1,809.0)	7,052
-10	(1,044.0)	88.7	-10	(2,010.0)	7,058

WEIGHTING FACTOR = 2.19

WEIGHTING FACTOR = 4.22

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GENERATING PERFORMANCE INCENTIVE POINTS TABLES
FLORIDA POWER & LIGHT COMPANY
PERIOD OF JANUARY THROUGH DECEMBER, 2019

UNIT: Ft. Myers 2

EQUIVALENT AVAILABILITY POINTS	FUEL SAVINGS/(LOSS) ($000)	ADJUSTED ACTUAL EQUIVALENT AVAILABILITY	AVERAGE HEAT RATE POINTS	FUEL SAVING/(LOSS) ($000)	ADJUSTED ACTUAL AVG. HEAT RATES
+10	1,195.0	84.0	+10	3,052.0	7,167
+9	1,075.5	83.8	+9	2,746.8	7,173
+8	956.0	83.5	+8	2,441.6	7,178
+7	836.5	83.3	+7	2,136.4	7,184
+6	717.0	83.0	+6	1,831.2	7,189
+5	597.5	82.8	+5	1,526.0	7,195
+4	478.0	82.5	+4	1,220.8	7,201
+3	358.5 <- Fuel Sav/(Loss) 382.4	82.3 <- Adj. Act. EAF= 82.3	+3	915.6	7,206
+2	239.0	82.0	+2	610.4	7,212
+1	119.5	81.8	+1	305.2	7,217
				0	7,223
0	0	81.5	0	0	7,298
				0	7,373
-1	(119.5)	81.3	-1	(305.2)	7,379
-2	(239.0)	81.0	-2	(610.4)	7,384
-3	(358.5)	80.8	-3	(915.6)	7,390
-4	(478.0)	80.5	-4	(1,220.8)	7,395
-5	(597.5)	80.3	-5	(1,526.0)	7,401
-6	(717.0)	80.0	-6	(1,831.2)	7,407
-7	(836.5)	79.8	-7	(2,136.4)	7,412
-8	(956.0)	79.5	-8	(2,441.6)	7,418
-9	(1,075.5)	79.3	-9	(2,746.8)	7,423
-10	(1,195.0)	79.0	-10	(3,052.0) <- Fuel Sav/(Loss)	7,429 <- Adj. Act. HR=7.614
	WEIGHTING FACTOR =	2.51		WEIGHTING FACTOR =	6.41

GENERATING PERFORMANCE INCENTIVE POINTS TABLES
FLORIDA POWER & LIGHT COMPANY
PERIOD OF JANUARY THROUGH DECEMBER, 2019

UNIT: Martin 8

EQUIVALENT AVAILABILITY POINTS	FUEL SAVINGS/(LOSS) ($000)		ADJUSTED ACTUAL EQUIVALENT AVAILABILITY		AVERAGE HEAT RATE POINTS	FUEL SAVING/(LOSS) ($000)		ADJUSTED ACTUAL AVG. HEAT RATES	
+10	1,047.0		93.3		+10	2,286.0		6,825	
+9	942.3		93.1		+9	2,057.4		6,833	
+8	837.6		92.8		+8	1,828.8		6,840	
+7	732.9		92.6		+7	1,600.2		6,848	
+6	628.2		92.3		+6	1,371.6		6,856	
+5	523.5		92.1		+5	1,143.0		6,864	
+4	418.8		91.8		+4	914.4		6,871	
+3	314.1	<- Fuel Sav/(Loss)	91.6	<- Adj. Act. EAF= 91.7	+3	685.8		6,879	
+2	209.4		91.3		+2	457.2		6,887	
+1	104.7		91.1		+1	228.6		6,894	
						0	<- Fuel Sav/(Loss)	6,902	<- Adj. Act. HR=6,952
0	0		90.8		0	0		6,977	
						0		7,052	
-1	(104.7)		90.6		-1	(228.6)		7,060	
-2	(209.4)		90.3		-2	(457.2)		7,067	
-3	(314.1)		90.1		-3	(685.8)		7,075	
-4	(418.8)		89.8		-4	(914.4)		7,083	
-5	(523.5)		89.6		-5	(1,143.0)		7,091	
-6	(628.2)		89.3		-6	(1,371.6)		7,098	
-7	(732.9)		89.1		-7	(1,600.2)		7,106	
-8	(837.6)		88.8		-8	(1,828.8)		7,114	
-9	(942.3)		88.6		-9	(2,057.4)		7,121	
-10	(1,047.0)		88.3		-10	(2,286.0)		7,129	

WEIGHTING FACTOR = 2.20

WEIGHTING FACTOR = 4.80

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GENERATING PERFORMANCE INCENTIVE POINTS TABLES
FLORIDA POWER & LIGHT COMPANY
PERIOD OF JANUARY THROUGH DECEMBER, 2019

UNIT: Riviera 5

EQUIVALENT AVAILABILITY POINTS	FUEL SAVINGS/(LOSS) ($000)	ADJUSTED ACTUAL EQUIVALENT AVAILABILITY	AVERAGE HEAT RATE POINTS	FUEL SAVING/(LOSS) ($000)	ADJUSTED ACTUAL AVG. HEAT RATES
+10	1,270.0	89.2	+10	1,856.0	6,568
+9	1,143.0	89.0	+9	1,670.4 <- Fuel Sav/(Loss)	6,570 <- Adj. Act. HR=6,570
+8	1,016.0	88.7	+8	1,484.8	6,572
+7	889.0	88.5	+7	1,299.2	6,573
+6	762.0	88.2	+6	1,113.6	6,575
+5	635.0	88.0	+5	928.0	6,577
+4	508.0	87.7	+4	742.4	6,579
+3	381.0	87.5	+3	556.8	6,581
+2	254.0 <- Fuel Sav/(Loss)	87.2 <- Adj. Act. EAF= 87.4	+2	371.2	6,582
+1	127.0	87.0	+1	185.6	6,584
				0	6,586
0	0	86.7	0	0	6,661
				0	6,736
-1	(127.0)	86.5	-1	(185.6)	6,738
-2	(254.0)	86.2	-2	(371.2)	6,740
-3	(381.0)	86.0	-3	(556.8)	6,741
-4	(508.0)	85.7	-4	(742.4)	6,743
-5	(635.0)	85.5	-5	(928.0)	6,745
-6	(762.0)	85.2	-6	(1,113.6)	6,747
-7	(889.0)	85.0	-7	(1,299.2)	6,749
-8	(1,016.0)	84.7	-8	(1,484.8)	6,750
-9	(1,143.0)	84.5	-9	(1,670.4)	6,752
-10	(1,270.0)	84.2	-10	(1,856.0)	6,754
	WEIGHTING FACTOR =	2.67		WEIGHTING FACTOR =	3.90

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GENERATING PERFORMANCE INCENTIVE POINTS TABLES
FLORIDA POWER & LIGHT COMPANY
PERIOD OF JANUARY THROUGH DECEMBER, 2019

UNIT: St. Lucie 1

EQUIVALENT AVAILABILITY POINTS	FUEL SAVINGS/(LOSS) ($000)	ADJUSTED ACTUAL EQUIVALENT AVAILABILITY	AVERAGE HEAT RATE POINTS	FUEL SAVING/(LOSS) ($000)	ADJUSTED ACTUAL AVG. HEAT RATES
+10	4,157.0	87.6	+10	393.0	10,305
+9	3,741.3	87.3	+9	353.7	10,307
+8	3,325.6	87.0	+8	314.4	10,310
+7	2,909.9	86.7	+7	275.1	10,312
+6	2,494.2	86.4	+6	235.8	10,315
+5	2,078.5	86.1	+5	196.5	10,317
+4	1,662.8	85.8	+4	157.2	10,319
+3	1,247.1	85.5	+3	117.9	10,322
+2	831.4	85.2	+2	78.6	10,324
+1	415.7	84.9	+1	39.3	10,327
				0 <- Fuel Sav/(Loss)	10,329 <- Adj. Act. HR=10,397
0	0	84.6	0	0	10,404
				0	10,479
-1	(415.7)	84.3	-1	(39.3)	10,481
-2	(831.4)	84.0	-2	(78.6)	10,484
-3	(1,247.1)	83.7	-3	(117.9)	10,486
-4	(1,662.8)	83.4	-4	(157.2)	10,489
-5	(2,078.5)	83.1	-5	(196.5)	10,491
-6	(2,494.2)	82.8	-6	(235.8)	10,493
-7	(2,909.9)	82.5	-7	(275.1)	10,496
-8	(3,325.6)	82.2	-8	(314.4)	10,498
-9	(3,741.3)	81.9	-9	(353.7)	10,501
-10	(4,157.0) <- Fuel Sav/(Loss)	81.6 <- Adj. Act. EAF= 71.2	-10	(393.0)	10,503
	WEIGHTING FACTOR =	8.73		WEIGHTING FACTOR =	0.82

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GENERATING PERFORMANCE INCENTIVE POINTS TABLES
FLORIDA POWER & LIGHT COMPANY
PERIOD OF JANUARY THROUGH DECEMBER, 2019

UNIT: St. Lucie 2

EQUIVALENT AVAILABILITY POINTS	FUEL SAVINGS/(LOSS) ($000)	ADJUSTED ACTUAL EQUIVALENT AVAILABILITY	AVERAGE HEAT RATE POINTS	FUEL SAVING/(LOSS) ($000)	ADJUSTED ACTUAL AVG. HEAT RATES
+10	3,848.0 <- Fuel Sav/(Loss) 3,848.0	96.6 <- Adj. Act. EAF= 100.0	+10	344.0	10,178
+9	3,463.2	96.3	+9	309.6	10,180
+8	3,078.4	96.0	+8	275.2	10,181
+7	2,693.6	95.7	+7	240.8	10,183
+6	2,308.8	95.4	+6	206.4	10,184
+5	1,924.0	95.1	+5	172.0	10,186
+4	1,539.2	94.8	+4	137.6	10,187
+3	1,154.4	94.5	+3	103.2	10,189
+2	769.6	94.2	+2	68.8	10,190
+1	384.8	93.9	+1	34.4	10,192
				0 <- Fuel Sav/(Loss)	10,193 <- Adj. Act. HR=10,248
0	0	93.6	0	0	10,268
				0	10,343
-1	(384.8)	93.3	-1	(34.4)	10,345
-2	(769.6)	93.0	-2	(68.8)	10,346
-3	(1,154.4)	92.7	-3	(103.2)	10,348
-4	(1,539.2)	92.4	-4	(137.6)	10,349
-5	(1,924.0)	92.1	-5	(172.0)	10,351
-6	(2,308.8)	91.8	-6	(206.4)	10,352
-7	(2,693.6)	91.5	-7	(240.8)	10,354
-8	(3,078.4)	91.2	-8	(275.2)	10,355
-9	(3,463.2)	90.9	-9	(309.6)	10,357
-10	(3,848.0)	90.6	-10	(344.0)	10,358

WEIGHTING FACTOR = 8.08

WEIGHTING FACTOR = 0.72

GENERATING PERFORMANCE INCENTIVE POINTS TABLES
FLORIDA POWER & LIGHT COMPANY
PERIOD OF JANUARY THROUGH DECEMBER, 2019

UNIT: Turkey Point 3

EQUIVALENT AVAILABILITY POINTS	FUEL SAVINGS/(LOSS) ($000)		ADJUSTED ACTUAL EQUIVALENT AVAILABILITY		AVERAGE HEAT RATE POINTS	FUEL SAVING/(LOSS) ($000)		ADJUSTED ACTUAL AVG. HEAT RATES	
+10	3,597.0	<- Fuel Sav/(Loss) 3,597.0	96.6	<- Adj. Act. EAF= 99.1	+10	674.0	<- Fuel Sav/(Loss) 674.0	10,866	<- Adj. Act. HR=10,594
+9	3,237.3		96.3		+9	606.6		10,874	
+8	2,877.6		96.0		+8	539.2		10,882	
+7	2,517.9		95.7		+7	471.8		10,890	
+6	2,158.2		95.4		+6	404.4		10,898	
+5	1,798.5		95.1		+5	337.0		10,906	
+4	1,438.8		94.8		+4	269.6		10,914	
+3	1,079.1		94.5		+3	202.2		10,922	
+2	719.4		94.2		+2	134.8		10,930	
+1	359.7		93.9		+1	67.4		10,938	
						0		10,946	
0	0		93.6		0	0		11,021	
						0		11,096	
-1	(359.7)		93.3		-1	(67.4)		11,104	
-2	(719.4)		93.0		-2	(134.8)		11,112	
-3	(1,079.1)		92.7		-3	(202.2)		11,120	
-4	(1,438.8)		92.4		-4	(269.6)		11,128	
-5	(1,798.5)		92.1		-5	(337.0)		11,136	
-6	(2,158.2)		91.8		-6	(404.4)		11,144	
-7	(2,517.9)		91.5		-7	(471.8)		11,152	
-8	(2,877.6)		91.2		-8	(539.2)		11,160	
-9	(3,237.3)		90.9		-9	(606.6)		11,168	
-10	(3,597.0)		90.6		-10	(674.0)		11,176	
	WEIGHTING FACTOR =		7.55			WEIGHTING FACTOR =		1.41	

GENERATING PERFORMANCE INCENTIVE POINTS TABLES
FLORIDA POWER & LIGHT COMPANY
PERIOD OF JANUARY THROUGH DECEMBER, 2019

UNIT: Turkey Point 4

EQUIVALENT AVAILABILITY POINTS	FUEL SAVINGS/(LOSS) ($000)		ADJUSTED ACTUAL EQUIVALENT AVAILABILITY		AVERAGE HEAT RATE POINTS	FUEL SAVING/(LOSS) ($000)		ADJUSTED ACTUAL AVG. HEAT RATES	
+10	3,263.0	<- Fuel Sav/(Loss) 3,263.0	84.3	<- Adj. Act. EAF= 87.6	+10	612.0		10,707	
+9	2,936.7		84.0		+9	550.8		10,724	
+8	2,610.4		83.7		+8	489.6		10,741	
+7	2,284.1		83.4		+7	428.4		10,759	
+6	1,957.8		83.1		+6	367.2		10,776	
+5	1,631.5		82.8		+5	306.0		10,793	
+4	1,305.2		82.5		+4	244.8		10,810	
+3	978.9		82.2		+3	183.6		10,827	
+2	652.6		81.9		+2	122.4		10,845	
+1	326.3		81.6		+1	61.2		10,862	
						0	<- Fuel Sav/(Loss)	10,879	<- Adj. Act. HR=10,942
0	0		81.3		0	0		10,954	
						0		11,029	
-1	(326.3)		81.0		-1	(61.2)		11,046	
-2	(652.6)		80.7		-2	(122.4)		11,063	
-3	(978.9)		80.4		-3	(183.6)		11,081	
-4	(1,305.2)		80.1		-4	(244.8)		11,098	
-5	(1,631.5)		79.8		-5	(306.0)		11,115	
-6	(1,957.8)		79.5		-6	(367.2)		11,132	
-7	(2,284.1)		79.2		-7	(428.4)		11,149	
-8	(2,610.4)		78.9		-8	(489.6)		11,167	
-9	(2,936.7)		78.6		-9	(550.8)		11,184	
-10	(3,263.0)		78.3		-10	(612.0)		11,201	

WEIGHTING FACTOR = 6.85

WEIGHTING FACTOR = 1.28

GENERATING PERFORMANCE INCENTIVE POINTS TABLES
FLORIDA POWER & LIGHT COMPANY
PERIOD OF JANUARY THROUGH DECEMBER, 2019

UNIT: West County 1

EQUIVALENT AVAILABILITY POINTS	FUEL SAVINGS/(LOSS) ($000)		ADJUSTED ACTUAL EQUIVALENT AVAILABILITY		AVERAGE HEAT RATE POINTS	FUEL SAVING/(LOSS) ($000)		ADJUSTED ACTUAL AVG. HEAT RATES	
+10	1,913.0		90.4		+10	2,691.0		6,880	
+9	1,721.7		90.1		+9	2,421.9		6,886	
+8	1,530.4		89.8		+8	2,152.8		6,891	
+7	1,339.1		89.5		+7	1,883.7		6,897	
+6	1,147.8		89.2		+6	1,614.6		6,903	
+5	956.5		88.9		+5	1,345.5		6,909	
+4	765.2		88.6		+4	1,076.4		6,914	
+3	573.9		88.3		+3	807.3		6,920	
+2	382.6		88.0		+2	538.2		6,926	
+1	191.3		87.7		+1	269.1		6,931	
						0	<- Fuel Sav/(Loss)	6,937	<- Adj. Act. HR=7,010
0	0		87.4		0	0		7,012	
						0		7,087	
-1	(191.3)		87.1		-1	(269.1)		7,093	
-2	(382.6)		86.8		-2	(538.2)		7,098	
-3	(573.9)		86.5		-3	(807.3)		7,104	
-4	(765.2)		86.2		-4	(1,076.4)		7,110	
-5	(956.5)	<- Fuel Sav/(Loss)	85.9	<- Adj. Act. EAF= 85.9	-5	(1,345.5)		7,116	
-6	(1,147.8)		85.6		-6	(1,614.6)		7,121	
-7	(1,339.1)		85.3		-7	(1,883.7)		7,127	
-8	(1,530.4)		85.0		-8	(2,152.8)		7,133	
-9	(1,721.7)		84.7		-9	(2,421.9)		7,138	
-10	(1,913.0)		84.4		-10	(2,691.0)		7,144	

WEIGHTING FACTOR = 4.01

WEIGHTING FACTOR = 5.65

GENERATING PERFORMANCE INCENTIVE POINTS TABLES
FLORIDA POWER & LIGHT COMPANY
PERIOD OF JANUARY THROUGH DECEMBER, 2019

UNIT: West County 2

EQUIVALENT AVAILABILITY POINTS	FUEL SAVINGS/(LOSS) ($000)		ADJUSTED ACTUAL EQUIVALENT AVAILABILITY		AVERAGE HEAT RATE POINTS	FUEL SAVING/(LOSS) ($000)		ADJUSTED ACTUAL AVG. HEAT RATES	
+10	1,186.0	<- Fuel Sav/(Loss) 1,186.0	87.0	<- Adj. Act. EAF= 89.0	+10	2,626.0	<- Fuel Sav/(Loss) 2,626.0	6,807	<- Adj. Act. HR=6,787
+9	1,067.4		86.8		+9	2,363.4		6,813	
+8	948.8		86.5		+8	2,100.8		6,820	
+7	830.2		86.3		+7	1,838.2		6,826	
+6	711.6		86.0		+6	1,575.6		6,833	
+5	593.0		85.8		+5	1,313.0		6,839	
+4	474.4		85.5		+4	1,050.4		6,845	
+3	355.8		85.3		+3	787.8		6,852	
+2	237.2		85.0		+2	525.2		6,858	
+1	118.6		84.8		+1	262.6		6,865	
						0		6,871	
0	0		84.5		0	0		6,946	
						0		7,021	
-1	(118.6)		84.3		-1	(262.6)		7,027	
-2	(237.2)		84.0		-2	(525.2)		7,034	
-3	(355.8)		83.8		-3	(787.8)		7,040	
-4	(474.4)		83.5		-4	(1,050.4)		7,047	
-5	(593.0)		83.3		-5	(1,313.0)		7,053	
-6	(711.6)		83.0		-6	(1,575.6)		7,059	
-7	(830.2)		82.8		-7	(1,838.2)		7,066	
-8	(948.8)		82.5		-8	(2,100.8)		7,072	
-9	(1,067.4)		82.3		-9	(2,363.4)		7,079	
-10	(1,186.0)		82.0		-10	(2,626.0)		7,085	

WEIGHTING FACTOR = 2.49

WEIGHTING FACTOR = 5.51

GENERATING PERFORMANCE INCENTIVE POINTS TABLES
FLORIDA POWER & LIGHT COMPANY
PERIOD OF JANUARY THROUGH DECEMBER, 2019

UNIT: West County 3

EQUIVALENT AVAILABILITY POINTS	FUEL SAVINGS/(LOSS) ($000)		ADJUSTED ACTUAL EQUIVALENT AVAILABILITY		AVERAGE HEAT RATE POINTS	FUEL SAVING/(LOSS) ($000)		ADJUSTED ACTUAL AVG. HEAT RATES	
+10	1,972.0	<- Fuel Sav/(Loss) 1,972.0	89.8		+10	2,943.0	<- Fuel Sav/(Loss) 2,943.0	6,843	<- Adj. Act. HR=6,830
+9	1,774.8		89.5		+9	2,648.7		6,849	
+8	1,577.6		89.2		+8	2,354.4		6,856	
+7	1,380.4		88.9		+7	2,060.1		6,862	
+6	1,183.2		88.6		+6	1,765.8		6,869	
+5	986.0		88.3		+5	1,471.5		6,875	
+4	788.8	<- Fuel Sav/(Loss)	88.0	<- Adj. Act. EAF= 88.2	+4	1,177.2		6,881	
+3	591.6		87.7		+3	882.9		6,888	
+2	394.4		87.4		+2	588.6		6,894	
+1	197.2		87.1		+1	294.3		6,901	
						0		6,907	
0	0		86.8		0	0		6,982	
						0		7,057	
-1	(197.2)		86.5		-1	(294.3)		7,063	
-2	(394.4)		86.2		-2	(588.6)		7,070	
-3	(591.6)		85.9		-3	(882.9)		7,076	
-4	(788.8)		85.6		-4	(1,177.2)		7,083	
-5	(986.0)		85.3		-5	(1,471.5)		7,089	
-6	(1,183.2)		85.0		-6	(1,765.8)		7,095	
-7	(1,380.4)		84.7		-7	(2,060.1)		7,102	
-8	(1,577.6)		84.4		-8	(2,354.4)		7,108	
-9	(1,774.8)		84.1		-9	(2,648.7)		7,115	
-10	(1,972.0)		83.8		-10	(2,943.0)		7,121	

WEIGHTING FACTOR = 4.14

WEIGHTING FACTOR = 6.18

ACTUAL PLANNED OUTAGES

FLORIDA POWER & LIGHT COMPANY

JANUARY THROUGH DECEMBER, 2019

PLANT/UNIT	ACTUAL PLANNED OUTAGE DATE	REASON FOR OUTAGE
Cape Canaveral 3	7/15/19-8/24/19 11/05/19-12/15/19	CT-32 Major CT-33 Major
Manatee 3	NONE	N/A
Ft. Myers 2	1/8/19-6/12/19; 6/19/19-6/19/19 1/8/19-1/16/19; 3/12/19-6/12/19 11/14/19-12/13/19; 11/4/19-12/14/19 1/1/19-1/4/19; 1/6/19-2/18/19	Steam turbine 1 upgrade and manual trip test Steam turbine 2 upgrade CT-2B air inlet structure modification; CT-2C 3SAR upgrade CT-2E 3SAR upgrade continued from prior year; CT-2F 3SAR upgrade
Martin 8	NONE	N/A
Riviera 5	2/15/19-4/5/19	CT-51 Major overhaul
St. Lucie 1	10/12/19-11/20/19	Main Steam Safety Valve (MSSV) testing & Refueling outage
St. Lucie 2	9/26/19	Turbine valve test (TVT)
Turkey Point 3	NONE	N/A
Turkey Point 4	3/8/19-4/15/19	Refueling
West County 1	NONE	N/A
West County 2	3/30/19-5/13/19; 4/2/19-5/16/19 4/6/19-5/19/19	CT-2A Hot Gas Path (HGP); CT-2B Hot Gas Path (HGP) CT-2C Hot Gas Path (HGP)
West County 3	NONE	N/A

WITNESS: CHARLES R. ROTE

GENERATING PERFORMANCE INCENTIVE FACTOR

JANUARY THROUGH DECEMBER, 2021

SEPTEMBER 3, 2020

CRR-2
DOCKET NO. 20200001-EI
FPL Witness: Charles R. Rote
Exhibit No.: ____________________
Pages 1 - 36

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20200001-EI EXHIBIT: 20
PARTY: FLORIDA POWER & LIGHT COMPANY – DIRECT
DESCRIPTION: C.R. Rote CRR-2

EXHIBIT INDEX

FLORIDA POWER & LIGHT COMPANY

JANUARY THROUGH DECEMBER, 2021

EXHIBIT	PAGE NUMBER	TITLE
CRR-2	7.201.001	Exhibit Index
	7.201.002	Projected System Generation
	7.201.003	Units Used to Determine GPIF
	7.201.004	GPIF Reward/Penalty Table (Estimated)
	7.201.005	GPIF Calculation of Maximum Allowed Incentive Dollars (Estimated)
	7.201.006 and 7.201.007	GPIF Target and Range Summary
	7.201.008	GPIF Projected Unit Heat Rate Equations
	7.201.009	Derivation of Weighting Factors
	7.201.010 - 7.201.022	Estimated Unit Performance Data
	7.201.023 - 7.201.035	Unit FOF and MOF vs Time Graphs
	7.201.036	Planned Outages Schedule (Estimated)

Projected System Generation
January Through December, 2021

Name	Capacity (MW)	Service Hours	Net Output MWH	NOF %	% of Total Output	Cumulative % of Total Output	Production Cost ($000)
Okeechobee	1,618	8,280	11,589,983	86.5	9.4	9.4	193,000
Port Everglades 5	1,254	8,280	9,360,940	90.2	7.6	17.0	159,978
West County 2	1,223	8,520	8,251,947	79.2	6.7	23.7	143,772
West County 3	1,228	8,760	7,970,273	74.1	6.5	30.2	139,175
Ft. Myers 2	1,730	8,592	7,838,813	52.7	6.4	36.5	152,928
St. Lucie 1	981	7,944	7,675,863	98.5	6.2	42.8	37,943
West County 1	1,223	8,471	7,565,632	73.0	6.1	48.9	132,534
Riviera 5	1,308	8,088	7,325,930	69.3	5.9	54.9	130,763
Turkey Point 4	841	8,760	7,278,511	98.8	5.9	60.8	44,633
Cape Canaveral 3	1,308	8,760	6,918,081	60.4	5.6	66.4	124,987
Turkey Point 3	837	8,064	6,655,501	98.6	5.4	71.8	34,320
St. Lucie 2	840	7,920	6,555,277	98.5	5.3	77.1	30,182
Sanford 5	1,147	8,424	4,706,240	48.7	3.8	80.9	89,896
Turkey Point 5	1,256	6,225	3,780,056	48.3	3.1	84.0	73,885
Manatee 3	1,223	3,848	3,349,780	71.2	2.7	86.7	64,160
Sanford 4	1,147	4,809	2,841,386	51.5	2.3	89.0	54,158
Martin 8	1,218	2,587	2,474,922	78.5	2.0	91.0	46,514
Scherer 4	636	8,760	2,174,478	39.0	1.8	92.8	62,980
Martin 3	464	6,961	1,564,261	48.4	1.3	94.1	31,307
Martin 4	464	3,192	761,214	51.4	0.6	94.7	15,091
Manatee 2	789	3,127	450,608	18.3	0.4	95.0	14,801
Manatee 1	789	1,768	284,679	20.4	0.2	95.3	10,460
Southfork PV Solar	74.5	4,502	203,036	60.5	0.2	95.4	0
Southfork PV Solar	74.5	4,502	203,036	60.5	0.2	95.6	0
Echo River PV Solar	74.5	4,655	198,396	57.2	0.2	95.8	0
Horizon PV Solar	74.5	4,502	183,041	54.6	0.1	95.9	0
Coral Farms PV Solar	74.5	4,474	182,310	54.7	0.1	96.1	0
Hammock PV Solar	74.5	4,502	181,818	54.2	0.1	96.2	0
Wildflower PV Solar	74.5	4,502	181,544	54.1	0.1	96.4	0
Loggerhead PV Solar	74.5	4,474	178,701	53.6	0.1	96.5	0
Blue Cypress PV Solar	74.5	4,474	177,362	53.2	0.1	96.7	0
Cattle Ranch PV Solar	74.5	4,563	177,284	52.2	0.1	96.8	0
Indian River PV Solar	74.5	4,474	177,229	53.2	0.1	96.9	0
Blue Heron PV Solar	74.5	4,502	177,036	52.8	0.1	97.1	0
Okeechobee PV Solar	74.5	4,474	176,734	53.0	0.1	97.2	0
Lakeside PV Solar	74.5	4,502	174,804	52.1	0.1	97.4	0
Trailside PV Solar	74.5	4,563	174,672	51.4	0.1	97.5	0
Magnolia Springs PV Solar	74.5	4,563	173,219	51.0	0.1	97.6	0
Union Springs PV Solar	74.5	4,563	173,041	50.9	0.1	97.8	0
Twin Lakes PV Solar	74.5	4,563	172,519	50.7	0.1	97.9	0
Barefoot Bay PV Solar	74.5	4,474	172,335	51.7	0.1	98.1	0
Egret PV Solar	74.5	4,563	171,972	50.6	0.1	98.2	0
Interstate PV Solar	74.5	4,474	171,862	51.6	0.1	98.3	0
Sunshine Gateway PV Solar	74.5	4,532	171,666	50.8	0.1	98.5	0
Miami-Dade PV Solar	74.5	4,474	171,187	51.4	0.1	98.6	0
Nassau PV Solar	74.5	4,563	171,168	50.4	0.1	98.8	0
Hibiscus PV Solar	74.5	4,474	170,974	51.3	0.1	98.9	0
Manatee PV Solar	74.5	4,809	168,695	47.1	0.1	99.0	0
Citrus PV Solar	74.5	4,778	167,642	47.1	0.1	99.2	0
Pioneer Trail PV Solar	74.5	4,474	167,568	50.3	0.1	99.3	0
Babcock PV Solar	74.5	4,840	166,050	46.1	0.1	99.4	0
Sweet Bay PV Solar	74.5	4,504	156,670	46.7	0.1	99.6	0
Northern PreservePV Solar	74.5	4,502	153,872	45.9	0.1	99.7	0
Lauderdale 6A	216	397	79,551	92.8	0.1	99.8	2,201
Lauderdale 6B	216	376	75,332	92.8	0.1	99.8	2,083
Ft. Myers 3C	219	251	50,613	92.1	0.0	99.9	1,393
Ft. Myers 3D	219	247	49,852	92.2	0.0	99.9	1,377
DeSoto Solar	25	4,686	47,955	40.9	0.0	99.9	0
Space Coast Solar	10	4,715	17,396	36.9	0.0	100.0	0
Lauderdale 6D	216	91	16,951	86.2	0.0	100.0	730
Lauderdale 6C	216	69	13,188	88.5	0.0	100.0	529
Lauderdale 6E	216	68	13,099	89.2	0.0	100.0	447
Ft. Myers 3B	168	25	2,615	62.3	0.0	100.0	584
Ft. Myers 3A	164	15	1,488	60.5	0.0	100.0	342
Total	**27,718**		**123,189,858**		**100.0**		**1,797,152**

UNITS TO BE USED TO DETERMINE THE GENERATING PERFORMANCE INCENTIVE FACTOR

FLORIDA POWER & LIGHT COMPANY JANUARY THROUGH DECEMBER, 2021

Cape Canaveral 3

Ft. Myers 2

Sanford 5

Port Everglades 5

Riviera 5

St. Lucie 1

St. Lucie 2

Turkey Point 3

Turkey Point 4

Turkey Point 5

West County 1

West County 2

West County 3

GENERATING PERFORMANCE INCENTIVE FACTOR

REWARD/PENALTY TABLE (ESTIMATED)

FLORIDA POWER & LIGHT COMPANY
JANUARY THROUGH DECEMBER, 2021

Generating Performance Incentive Points (GPIF)	Fuel Savings/(Loss) ($000)	Generating Performance Incentive Factor ($000)
+ 10	41,028	20,514
+ 9	36,925	18,463
+ 8	32,822	16,411
+ 7	28,720	14,360
+ 6	24,617	12,308
+ 5	20,514	10,257
+ 4	16,411	8,206
+ 3	12,308	6,154
+ 2	8,206	4,103
+ 1	4,103	2,051
0	0	0
- 1	(4,103)	(2,051)
- 2	(8,206)	(4,103)
- 3	(12,308)	(6,154)
- 4	(16,411)	(8,206)
- 5	(20,514)	(10,257)
- 6	(24,617)	(12,308)
- 7	(28,720)	(14,360)
- 8	(32,822)	(16,411)
- 9	(36,925)	(18,463)
- 10	(41,028)	(20,514)

GENERATING PERFORMANCE INCENTIVE FACTOR

CALCULATION OF MAXIMUM ALLOWED INCENTIVE DOLLARS (ESTIMATED)

FLORIDA POWER & LIGHT COMPANY
PERIOD OF: JANUARY THROUGH DECEMBER, 2021

LINE 1	BEGINNING OF PERIOD BALANCE OF COMMON EQUITY		$	24,040,875,343	
	END OF MONTH BALANCE OF COMMON EQUITY				
LINE 2	MONTH OF JANUARY	2021	$	24,320,233,738	
LINE 3	MONTH OF FEBRUARY	2021	$	24,522,998,699	
LINE 4	MONTH OF MARCH	2021	$	25,073,532,609	
LINE 5	MONTH OF APRIL	2021	$	25,307,078,937	
LINE 6	MONTH OF MAY	2021	$	25,577,484,577	
LINE 7	MONTH OF JUNE	2021	$	25,882,306,540	
LINE 8	MONTH OF JULY	2021	$	26,183,609,065	
LINE 9	MONTH OF AUGUST	2021	$	26,734,032,866	
LINE 10	MONTH OF SEPTEMBER	2021	$	26,944,703,187	
LINE 11	MONTH OF OCTOBER	2021	$	27,164,891,301	
LINE 12	MONTH OF NOVEMBER	2021	$	27,393,075,499	
LINE 13	MONTH OF DECEMBER	2021	$	27,534,711,853	
LINE 14	AVERAGE COMMON EQUITY FOR THE PERIOD (SUMMATION OF LINE 1 THROUGH LINE 13 DIVIDED BY 13)		$	25,898,425,709	
LINE 15	25 BASIS POINTS			0.0025	
LINE 16	REVENUE EXPANSION FACTOR			75.4238%	
LINE 17	MAXIMUM ALLOWED INCENTIVE DOLLARS (LINE 14 TIMES LINE 15 DIVIDED BY LINE 16)		$	85,843,015	
LINE 18	JURISDICTIONAL SALES			111,812,879,706	KWH
LINE 19	TOTAL SALES			117,532,613,699	KWH
LINE 20	JURISDICTIONAL SEPARATION FACTOR (LINE 18 DIVIDED BY LINE 19)			95.13%	
LINE 21	MAXIMUM ALLOWED JURISDICTIONAL INCENTIVE DOLLARS (LINE 17 TIMES LINE 20)		$	81,662,460	
LINE 22	INCENTIVE CAP (50 PECENT OF PROJECTED FUEL SAVINGS AT 10 GPIF·POINT LEVEL FROM SHEET NO. 3.515)		$	20,514,000	
LINE 23	MAXIMUM ALLOWED GPIF REWARD (AT 10 GPIF-POINT LEVEL) (THE LESSER OF LINE 21 AND LINE 22)		$	20,514,000	

Note: Line 22 and 23 are as approved by Commission order PSC-13-0665-FOF-EI dated 12/18/13 effective 1/1/14.

GPIF TARGET AND RANGE SUMMARY

FLORIDA POWER & LIGHT COMPANY
PERIOD OF: JANUARY THROUGH DECEMBER, 2021

Plant / Unit	Weighting Factor (%)	EAF Target (%)	EAF Range Max. (%)	EAF Range Min. (%)	Max. Fuel Savings ($000's)	Max. Fuel Loss ($000's)
Cape Canaveral 3	1.05	90.1	92.6	87.6	430	-430
Sanford 5	0.51	90.4	92.9	87.9	209	-209
Ft. Myers 2	0.70	91.2	93.7	88.7	288	-288
Port Everglades 5	2.31	84.0	87.0	81.0	949	-949
Riviera 5	1.25	84.6	87.1	82.1	512	-512
St. Lucie 1	9.28	80.6	84.1	77.1	3,807	-3,807
St. Lucie 2	6.86	84.0	87.0	81.0	2,815	-2,815
Turkey Point 3	6.75	85.7	88.7	82.7	2,769	-2,769
Turkey Point 4	6.86	93.6	96.6	90.6	2,816	-2,816
Turkey Point 5	0.48	80.6	83.6	77.6	194	-194
West County 1	1.42	91.0	93.5	88.5	581	-581
West County 2	1.57	89.7	92.2	87.2	643	-643
West County 3	1.52	83.2	85.7	80.7	622	-622
	40.56				16,635	-16,635

GPIF TARGET AND RANGE SUMMARY

FLORIDA POWER & LIGHT COMPANY
PERIOD OF: JANUARY THROUGH DECEMBER, 2021

Plant / Unit	Weighting Factor (%)	ANOHR TARGET BTU/KWH	ANOHR TARGET NOF	ANOHR RANGE BTU/KWH	ANOHR RANGE BTU/KWH	Max. Fuel Savings ($000's)	Max. Fuel Loss ($000's)
Cape Canaveral 3	3.85	6,640	60.4	6,556	6,724	1,581	-1,581
Sanford 5	5.26	7,372	48.7	7,195	7,549	2,158	-2,158
Ft. Myers 2	7.98	7,189	52.7	7,035	7,343	3,276	-3,276
Port Everglades 5	6.23	6,566	90.2	6,461	6,671	2,558	-2,558
Riviera 5	4.43	6,545	69.3	6,454	6,636	1,818	-1,818
St. Lucie 1	0.88	10,422	98.5	10,322	10,522	363	-363
St. Lucie 2	0.65	10,297	98.5	10,205	10,389	267	-267
Turkey Point 3	2.02	11,234	98.6	10,976	11,492	828	-828
Turkey Point 4	1.57	10,888	98.8	10,735	11,041	643	-643
Turkey Point 5	2.89	7,350	48.3	7,232	7,468	1,186	-1,186
West County 1	7.37	7,098	73.0	6,936	7,260	3,025	-3,025
West County 2	8.71	6,882	79.2	6,711	7,053	3,572	-3,572
West County 3	7.60	6,919	74.1	6,764	7,074	3,118	-3,118
	59.44					24,393	-24,393

GENERATING PERFORMANCE INCENTIVE FACTOR
PROJECTED UNIT HEAT RATE EQUATIONS
FLORIDA POWER & LIGHT COMPANY
PERIOD OF: JANUARY THROUGH DECEMBER, 2021

				ANOHR Equation					
Plant/Unit	ANOHR	NOF	MW	a coef.	b coef.	Bounds	First	Last	Exclusions
Cape Canaveral 3	6,640	60.4	1308	6830	-3.14	84	07-17	06-20	None
Sanford 5	7,372	48.7	1147	7731	-7.37	177	07-17	06-20	3/19, 4/19, 5/19, 6/19
Ft. Myers 2	7,189	52.7	1730	7344	-2.94	154	07-17	06-20	12/17, 3/19, 4/19, 5/19, 6/19, 2/20
Port Everglades 5	6,566	90.2	1254	7158	-6.56	105	07-17	06-20	11/17, 12/17, 1/18
Riviera 5	6,545	69.3	1308	7072	-7.61	91	07-17	06-20	7/17, 10/18
St. Lucie 1	10,422	98.5	981	13878	-35.09	100	07-17	06-20	5/19
St. Lucie 2	10,297	98.5	840	13528	-32.80	92	07-17	06-20	8/18, 9/18
Turkey Point 3	11,234	98.6	837	25954	-149.29	258	07-17	06-20	10/18, 11/18, 9/19, 3/20, 4/20
Turkey Point 4	10,888	98.8	841	14199	-33.51	153	07-17	06-20	10/17
Turkey Point 5	7,350	48.3	1256	7972	-12.88	118	07-17	06-20	10/17, 11/17, 1/18, 2/18, 10/19, 11/19, 12/19
West County 1	7,098	73.0	1223	7578	-6.57	162	07-17	06-20	11/18
West County 2	6,882	79.2	1223	7497	-7.77	171	07-17	06-20	10/17, 12/17, 4/19
West County 3	6,919	74.1	1228	7430	-6.90	155	07-17	06-20	11/17

DERIVATION OF WEIGHTING FACTORS

FLORIDA POWER & LIGHT COMPANY
PERIOD OF: JANUARY THROUGH DECEMBER, 2021

PRODUCTION COSTING SIMULATION
FUEL COST ($000)

Unit	Performance Indicator	At Target (1)	At Maximum Improvement (2)	Savings (3)	Factor (% Of Savings)
Cape Canaveral 3	EAF	1,797,152	1,796,722	430	1.05
Cape Canaveral 3	ANOHR	1,797,152	1,795,571	1,581	3.85
Sanford 5	EAF	1,797,152	1,796,943	209	0.51
Sanford 5	ANOHR	1,797,152	1,794,994	2,158	5.26
Ft. Myers 2	EAF	1,797,152	1,796,864	288	0.70
Ft. Myers 2	ANOHR	1,797,152	1,793,876	3,276	7.98
Port Everglades 5	EAF	1,797,152	1,796,203	949	2.31
Port Everglades 5	ANOHR	1,797,152	1,794,594	2,558	6.23
Riviera 5	EAF	1,797,152	1,796,640	512	1.25
Riviera 5	ANOHR	1,797,152	1,795,334	1,818	4.43
St. Lucie 1	EAF	1,797,152	1,793,345	3,807	9.28
St. Lucie 1	ANOHR	1,797,152	1,796,789	363	0.88
St. Lucie 2	EAF	1,797,152	1,794,337	2,815	6.86
St. Lucie 2	ANOHR	1,797,152	1,796,885	267	0.65
Turkey Point 3	EAF	1,797,152	1,794,383	2,769	6.75
Turkey Point 3	ANOHR	1,797,152	1,796,324	828	2.02
Turkey Point 4	EAF	1,797,152	1,794,336	2,816	6.86
Turkey Point 4	ANOHR	1,797,152	1,796,509	643	1.57
Turkey Point 5	EAF	1,797,152	1,796,958	194	0.48
Turkey Point 5	ANOHR	1,797,152	1,795,966	1,186	2.89
West County 1	EAF	1,797,152	1,796,571	581	1.42
West County 1	ANOHR	1,797,152	1,794,127	3,025	7.37
West County 2	EAF	1,797,152	1,796,509	643	1.57
West County 2	ANOHR	1,797,152	1,793,580	3,572	8.71
West County 3	EAF	1,797,152	1,796,530	622	1.52
West County 3	ANOHR	1,797,152	1,794,034	3,118	7.60
	TOTAL			41,028	100.00

(1) FUEL ADJUSTMENT - ALL UNITS PERFORMANCE AT TARGET
(2) ALL OTHER UNITS PERFORMANCE AT TARGET
(3) EXPRESSED IN REPLACEMENT ENERGY COSTS.

ESTIMATED UNIT PERFORMANCE DATA

FLORIDA POWER & LIGHT

PERIOD OF: JANUARY THROUGH DECEMBER, 2021

	Cape Canaveral 3	Jan '21	Feb '21	Mar '21	Apr '21	May '21	Jun '21
1	EAF (%)	92.6	81.6	92.6	92.6	92.6	92.6
2	EPOF (%)	0.0	11.9	0.0	0.0	0.0	0.0
3	EUOF (%)	7.4	6.5	7.4	7.4	7.4	7.4
4	EUOR (%)	7.4	6.5	7.4	7.4	7.4	7.4
5	PH	744	672	744	720	744	720
6	SH	744	672	744	720	744	720
7	RSH	0	0	0	0	0	0
8	UH	0	0	0	0	0	0
9	POH	0	0	0	0	0	0
10	FOH & EFOH	15	12	15	15	15	15
11	MOH & EMOH	40	32	40	38	40	38
12	Oper Mbtu	2,969,877	3,014,481	4,345,240	4,185,975	4,149,923	3,879,763
13	Net Gen (MWH)	444,127	452,014	656,579	632,418	626,120	584,742
14	ANOHR (Btu/KWH)	6,687	6,669	6,618	6,619	6,628	6,635
15	NOF (%)	45.6	51.4	67.5	67.2	64.3	62.1
16	NSC (MW)	1,308	1,308	1,308	1,308	1,308	1,308
17	ANOHR Equation	-3.14 x NOF + 6830					

	Cape Canaveral 3	Jul '21	Aug '21	Sep '21	Oct '21	Nov '21	Dec '21	Total
1	EAF (%)	92.6	92.6	92.6	92.6	80.3	84.6	90.1
2	EPOF (%)	0.0	0.0	0.0	0.0	13.3	8.6	2.7
3	EUOF (%)	7.4	7.4	7.4	7.4	6.4	6.8	7.2
4	EUOR (%)	7.4	7.4	7.4	7.4	6.4	6.8	7.2
5	PH	744	744	720	744	720	744	8,760
6	SH	744	744	720	744	720	744	8,760
7	RSH	0	0	0	0	0	0	0
8	UH	0	0	0	0	0	0	0
9	POH	0	0	0	0	0	0	0
10	FOH & EFOH	15	15	15	15	13	14	175
11	MOH & EMOH	40	40	38	40	33	36	456
12	Oper Mbtu	4,191,767	4,275,362	4,044,670	4,129,456	3,492,511	3,241,490	45,936,058
13	Net Gen (MWH)	632,624	645,630	610,332	622,938	524,795	485,762	6,918,081
14	ANOHR (Btu/KWH)	6,626	6,622	6,627	6,629	6,655	6,673	6,640
15	NOF (%)	65.0	66.3	64.8	64.0	55.7	49.9	60.4
16	NSC (MW)	1,308	1,308	1,308	1,308	1,308	1,308	1,308
17	ANOHR Equation	-3.14 x NOF + 6830						

ESTIMATED UNIT PERFORMANCE DATA

FLORIDA POWER & LIGHT

PERIOD OF: JANUARY THROUGH DECEMBER, 2021

	Ft. Myers 2	Jan '21	Feb '21	Mar '21	Apr '21	May '21	Jun '21
1	EAF (%)	94.2	92.1	89.4	94.2	94.2	94.2
2	EPOF (%)	0.0	2.2	5.1	0.0	0.0	0.0
3	EUOF (%)	5.8	5.7	5.5	5.8	5.8	5.8
4	EUOR (%)	5.8	6.1	6.5	5.8	5.8	5.8
5	PH	744	672	744	720	744	720
6	SH	744	624	624	720	744	720
7	RSH	0	48	120	0	0	0
8	UH	0	0	0	0	0	0
9	POH	0	0	0	0	0	0
10	FOH & EFOH	15	14	15	15	15	15
11	MOH & EMOH	28	24	26	27	28	27
12	Oper Mbtu	4,121,039	3,716,035	4,268,550	5,098,340	4,880,325	5,019,751
13	Net Gen (MWH)	571,335	515,901	594,340	710,471	678,860	699,227
14	ANOHR (Btu/KWH)	7,213	7,203	7,182	7,176	7,189	7,179
15	NOF (%)	44.4	47.8	55.1	57.0	52.7	56.1
16	NSC (MW)	1,730	1,730	1,730	1,730	1,730	1,730
17	ANOHR Equation	-2.94 x NOF + 7344					

	Ft. Myers 2	Jul '21	Aug '21	Sep '21	Oct '21	Nov '21	Dec '21	Total
1	EAF (%)	94.2	94.2	94.2	86.1	73.3	94.2	91.2
2	EPOF (%)	0.0	0.0	0.0	8.6	22.2	0.0	3.2
3	EUOF (%)	5.8	5.8	5.8	5.3	4.5	5.8	5.6
4	EUOR (%)	5.8	5.8	5.8	5.3	4.5	5.8	5.7
5	PH	744	744	720	744	720	744	8,760
6	SH	744	744	720	744	720	744	8,592
7	RSH	0	0	0	0	0	0	168
8	UH	0	0	0	0	0	0	0
9	POH	0	0	0	0	0	0	0
10	FOH & EFOH	15	15	15	14	12	15	175
11	MOH & EMOH	28	28	27	25	21	28	315
12	Oper Mbtu	5,202,356	5,494,293	5,047,613	5,140,368	4,143,814	4,208,289	56,353,227
13	Net Gen (MWH)	724,764	766,396	703,206	715,829	574,891	583,593	7,838,813
14	ANOHR (Btu/KWH)	7,178	7,169	7,178	7,181	7,208	7,211	7,189
15	NOF (%)	56.3	59.5	56.5	55.6	46.2	45.3	52.7
16	NSC (MW)	1,730	1,730	1,730	1,730	1,730	1,730	1,730
17	ANOHR Equation	-2.94 x NOF + 7344						

ESTIMATED UNIT PERFORMANCE DATA

FLORIDA POWER & LIGHT

PERIOD OF: JANUARY THROUGH DECEMBER, 2021

	Sanford 5	Jan '21	Feb '21	Mar '21	Apr '21	May '21	Jun '21
1	EAF (%)	94.0	94.0	57.6	87.7	94.0	94.0
2	EPOF (%)	0.0	0.0	38.7	6.7	0.0	0.0
3	EUOF (%)	6.0	6.0	3.7	5.6	6.0	6.0
4	EUOR (%)	6.0	6.0	6.0	6.0	6.0	6.0
5	PH	744	672	744	720	744	720
6	SH	744	672	456	672	744	720
7	RSH	0	0	0	0	0	0
8	UH	0	0	288	48	0	0
9	POH	0	0	288	48	0	0
10	FOH & EFOH	15	14	9	14	15	15
11	MOH & EMOH	29	27	18	27	29	28
12	Oper Mbtu	2,435,145	2,449,731	1,759,065	2,969,142	3,241,732	3,164,165
13	Net Gen (MWH)	326,909	330,375	237,840	404,295	441,052	430,733
14	ANOHR (Btu/KWH)	7,449	7,415	7,396	7,344	7,350	7,346
15	NOF (%)	38.3	42.9	45.5	52.5	51.7	52.2
16	NSC (MW)	1,147	1,147	1,147	1,147	1,147	1,147
17	ANOHR Equation	-7.37 x NOF + 7731					

	Sanford 5	Jul '21	Aug '21	Sep '21	Oct '21	Nov '21	Dec '21	Total
1	EAF (%)	94.0	94.0	94.0	94.0	94.0	94.0	90.4
2	EPOF (%)	0.0	0.0	0.0	0.0	0.0	0.0	3.8
3	EUOF (%)	6.0	6.0	6.0	6.0	6.0	6.0	5.8
4	EUOR (%)	6.0	6.0	6.0	6.0	6.0	6.0	6.0
5	PH	744	744	720	744	720	744	8,760
6	SH	744	744	720	744	720	744	8,424
7	RSH	0	0	0	0	0	0	0
8	UH	0	0	0	0	0	0	336
9	POH	0	0	0	0	0	0	336
10	FOH & EFOH	15	15	15	15	15	15	175
11	MOH & EMOH	29	29	28	29	28	29	333
12	Oper Mbtu	3,454,237	3,502,673	3,326,656	3,182,292	2,688,289	2,493,628	34,694,401
13	Net Gen (MWH)	471,697	478,638	454,089	432,553	362,939	335,120	4,706,240
14	ANOHR (Btu/KWH)	7,323	7,318	7,326	7,357	7,407	7,441	7,372
15	NOF (%)	55.3	56.1	55.0	50.7	43.9	39.3	48.7
16	NSC (MW)	1,147	1,147	1,147	1,147	1,147	1,147	1,147
17	ANOHR Equation	-7.37 x NOF + 7731						

ESTIMATED UNIT PERFORMANCE DATA

FLORIDA POWER & LIGHT

PERIOD OF: JANUARY THROUGH DECEMBER, 2021

	Port Everglades 5	Jan '21	Feb '21	Mar '21	Apr '21	May '21	Jun '21
1	EAF (%)	88.9	88.9	60.2	59.3	88.9	88.9
2	EPOF (%)	0.0	0.0	32.3	33.3	0.0	0.0
3	EUOF (%)	11.1	11.1	7.5	7.4	11.1	11.1
4	EUOR (%)	11.1	11.1	11.1	11.1	11.1	11.1
5	PH	744	672	744	720	744	720
6	SH	744	672	504	480	744	720
7	RSH	0	0	0	0	0	0
8	UH	0	0	240	240	0	0
9	POH	0	0	240	240	0	0
10	FOH & EFOH	38	34	26	24	38	37
11	MOH & EMOH	45	41	30	29	45	43
12	Oper Mbtu	5,544,263	4,956,315	3,758,540	3,499,989	5,429,235	5,315,564
13	Net Gen (MWH)	844,647	754,271	572,599	532,075	825,488	809,066
14	ANOHR (Btu/KWH)	6,564	6,571	6,564	6,578	6,577	6,570
15	NOF (%)	90.5	89.5	90.6	88.4	88.5	89.6
16	NSC (MW)	1,254	1,254	1,254	1,254	1,254	1,254
17	ANOHR Equation	-6.56 x NOF + 7158					

	Port Everglades 5	Jul '21	Aug '21	Sep '21	Oct '21	Nov '21	Dec '21	Total
1	EAF (%)	88.9	88.9	88.9	88.9	88.7	88.9	84.0
2	EPOF (%)	0.0	0.0	0.0	0.0	0.2	0.0	5.5
3	EUOF (%)	11.1	11.1	11.1	11.1	11.1	11.1	10.5
4	EUOR (%)	11.1	11.1	11.1	11.1	11.1	11.1	11.1
5	PH	744	744	720	744	720	744	8,760
6	SH	744	744	720	744	720	744	8,280
7	RSH	0	0	0	0	0	0	0
8	UH	0	0	0	0	0	0	480
9	POH	0	0	0	0	0	0	480
10	FOH & EFOH	38	38	37	38	36	38	420
11	MOH & EMOH	45	45	43	45	43	45	499
12	Oper Mbtu	5,497,303	5,530,168	5,370,140	5,563,520	5,432,223	5,572,100	61,463,932
13	Net Gen (MWH)	836,728	842,243	818,120	847,839	828,588	849,276	9,360,940
14	ANOHR (Btu/KWH)	6,570	6,566	6,564	6,562	6,556	6,561	6,566
15	NOF (%)	89.7	90.3	90.6	90.9	91.8	91.0	90.2
16	NSC (MW)	1,254	1,254	1,254	1,254	1,254	1,254	1,254
17	ANOHR Equation	-6.56 x NOF + 7158						

ESTIMATED UNIT PERFORMANCE DATA

FLORIDA POWER & LIGHT

PERIOD OF: JANUARY THROUGH DECEMBER, 2021

	Riviera 5	Jan '21	Feb '21	Mar '21	Apr '21	May '21	Jun '21
1	EAF (%)	91.7	91.7	91.7	6.1	91.7	91.7
2	EPOF (%)	0.0	0.0	0.0	93.3	0.0	0.0
3	EUOF (%)	8.3	8.3	8.3	0.6	8.3	8.3
4	EUOR (%)	8.3	8.3	8.3	8.3	8.3	8.3
5	PH	744	672	744	720	744	720
6	SH	744	672	744	48	744	720
7	RSH	0	0	0	0	0	0
8	UH	0	0	0	672	0	0
9	POH	0	0	0	672	0	0
10	FOH & EFOH	16	15	16	1	16	16
11	MOH & EMOH	46	41	46	3	46	44
12	Oper Mbtu	3,816,411	3,538,908	4,547,270	356,809	4,465,036	4,136,108
13	Net Gen (MWH)	576,410	535,468	696,686	55,795	682,936	630,216
14	ANOHR (Btu/KWH)	6,621	6,609	6,527	6,395	6,538	6,563
15	NOF (%)	59.2	60.9	71.6	88.9	70.2	66.9
16	NSC (MW)	1,308	1,308	1,308	1,308	1,308	1,308
17	ANOHR Equation	-7.61 x NOF + 7072					

	Riviera 5	Jul '21	Aug '21	Sep '21	Oct '21	Nov '21	Dec '21	Total
1	EAF (%)	91.7	91.7	91.7	91.7	91.5	91.7	84.6
2	EPOF (%)	0.0	0.0	0.0	0.0	0.2	0.0	7.7
3	EUOF (%)	8.3	8.3	8.3	8.3	8.3	8.3	7.7
4	EUOR (%)	8.3	8.3	8.3	8.3	8.3	8.3	8.3
5	PH	744	744	720	744	720	744	8,760
6	SH	744	744	720	744	720	744	8,088
7	RSH	0	0	0	0	0	0	0
8	UH	0	0	0	0	0	0	672
9	POH	0	0	0	0	0	0	672
10	FOH & EFOH	16	16	16	16	16	16	175
11	MOH & EMOH	46	46	44	46	44	46	499
12	Oper Mbtu	4,631,012	5,100,693	4,939,920	4,886,521	4,017,644	3,449,039	47,948,212
13	Net Gen (MWH)	710,714	790,315	765,523	753,860	610,677	517,330	7,325,930
14	ANOHR (Btu/KWH)	6,516	6,454	6,453	6,482	6,579	6,667	6,545
15	NOF (%)	73.0	81.2	81.3	77.5	64.8	53.2	69.2
16	NSC (MW)	1,308	1,308	1,308	1,308	1,308	1,308	1,308
17	ANOHR Equation	-7.61 x NOF + 7072						

ESTIMATED UNIT PERFORMANCE DATA

FLORIDA POWER & LIGHT

PERIOD OF: JANUARY THROUGH DECEMBER, 2021

	St. Lucie 1	Jan '21	Feb '21	Mar '21	Apr '21	May '21	Jun '21
1	EAF (%)	88.9	88.9	88.9	26.7	51.6	88.9
2	EPOF (%)	0.0	0.0	0.0	70.0	41.9	0.0
3	EUOF (%)	11.1	11.1	11.1	3.3	6.5	11.1
4	EUOR (%)	11.1	11.1	11.1	11.1	11.1	11.1
5	PH	744	672	744	720	744	720
6	SH	744	672	744	216	432	720
7	RSH	0	0	0	0	0	0
8	UH	0	0	0	504	312	0
9	POH	0	0	0	504	312	0
10	FOH & EFOH	57	51	57	16	33	55
11	MOH & EMOH	26	24	26	8	15	25
12	Oper Mbtu	7,552,398	6,821,523	7,552,398	2,160,303	4,320,606	7,201,018
13	Net Gen (MWH)	727,591	657,179	727,591	206,589	413,178	688,631
14	ANOHR (Btu/KWH)	10,380	10,380	10,380	10,457	10,457	10,457
15	NOF (%)	99.7	99.7	99.7	97.5	97.5	97.5
16	NSC (MW)	981	981	981	981	981	981
17	ANOHR Equation	-35.09 x NOF + 13878					

	St. Lucie 1	Jul '21	Aug '21	Sep '21	Oct '21	Nov '21	Dec '21	Total
1	EAF (%)	88.9	88.9	88.9	88.9	88.9	88.9	80.6
2	EPOF (%)	0.0	0.0	0.0	0.0	0.0	0.0	9.3
3	EUOF (%)	11.1	11.1	11.1	11.1	11.1	11.1	10.1
4	EUOR (%)	11.1	11.1	11.1	11.1	11.1	11.1	11.1
5	PH	744	744	720	744	720	744	8,760
6	SH	744	744	720	744	720	744	7,944
7	RSH	0	0	0	0	0	0	0
8	UH	0	0	0	0	0	0	816
9	POH	0	0	0	0	0	0	816
10	FOH & EFOH	57	57	55	57	55	57	604
11	MOH & EMOH	26	26	25	26	25	26	280
12	Oper Mbtu	7,441,054	7,441,054	7,201,018	7,441,054	7,308,777	7,552,398	79,997,841
13	Net Gen (MWH)	711,586	711,586	688,631	711,586	704,121	727,591	7,675,863
14	ANOHR (Btu/KWH)	10,457	10,457	10,457	10,457	10,380	10,380	10,422
15	NOF (%)	97.5	97.5	97.5	97.5	99.7	99.7	98.5
16	NSC (MW)	981	981	981	981	981	981	981
17	ANOHR Equation	-35.09 x NOF + 13878						

ESTIMATED UNIT PERFORMANCE DATA

FLORIDA POWER & LIGHT

PERIOD OF: JANUARY THROUGH DECEMBER, 2021

	St. Lucie 2	Jan '21	Feb '21	Mar '21	Apr '21	May '21	Jun '21
1	EAF (%)	92.9	92.9	92.9	92.9	92.9	92.9
2	EPOF (%)	0.0	0.0	0.0	0.0	0.0	0.0
3	EUOF (%)	7.1	7.1	7.1	7.1	7.1	7.1
4	EUOR (%)	7.1	7.1	7.1	7.1	7.1	7.1
5	PH	744	672	744	720	744	720
6	SH	744	672	744	720	744	720
7	RSH	0	0	0	0	0	0
8	UH	0	0	0	0	0	0
9	POH	0	0	0	0	0	0
10	FOH & EFOH	26	24	26	25	26	25
11	MOH & EMOH	26	24	26	25	26	25
12	Oper Mbtu	6,394,118	5,775,332	6,394,118	6,090,952	6,293,986	6,090,952
13	Net Gen (MWH)	623,512	563,172	623,512	589,637	609,292	589,637
14	ANOHR (Btu/KWH)	10,255	10,255	10,255	10,330	10,330	10,330
15	NOF (%)	99.8	99.8	99.8	97.5	97.5	97.5
16	NSC (MW)	840	840	840	840	840	840
17	ANOHR Equation	-32.8 x NOF + 13528					

	St. Lucie 2	Jul '21	Aug '21	Sep '21	Oct '21	Nov '21	Dec '21	Total
1	EAF (%)	92.9	80.9	0.0	89.9	92.9	92.9	84.0
2	EPOF (%)	0.0	12.9	100.0	3.2	0.0	0.0	9.6
3	EUOF (%)	7.1	6.2	0.0	6.9	7.1	7.1	6.4
4	EUOR (%)	7.1	7.1	0.0	7.1	7.1	7.1	7.1
5	PH	744	744	720	744	720	744	8,760
6	SH	744	648	0	720	720	744	7,920
7	RSH	0	0	0	0	0	0	0
8	UH	0	96	720	24	0	0	840
9	POH	0	96	720	24	0	0	840
10	FOH & EFOH	26	23	0	25	25	26	280
11	MOH & EMOH	26	23	0	25	25	26	280
12	Oper Mbtu	6,293,986	5,481,861	0	6,090,952	6,187,856	6,394,118	67,499,689
13	Net Gen (MWH)	609,292	530,674	0	589,637	603,399	623,512	6,555,277
14	ANOHR (Btu/KWH)	10,330	10,330	0	10,330	10,255	10,255	10,297
15	NOF (%)	97.5	97.5	0.0	97.5	99.8	99.8	98.5
16	NSC (MW)	840	840	840	840	840	840	840
17	ANOHR Equation	-32.8 x NOF + 13528						

ESTIMATED UNIT PERFORMANCE DATA

FLORIDA POWER & LIGHT

PERIOD OF: JANUARY THROUGH DECEMBER, 2021

	Turkey Point 3	Jan '21	Feb '21	Mar '21	Apr '21	May '21	Jun '21
1	EAF (%)	93.0	93.0	93.0	93.0	93.0	93.0
2	EPOF (%)	0.0	0.0	0.0	0.0	0.0	0.0
3	EUOF (%)	7.0	7.0	7.0	7.0	7.0	7.0
4	EUOR (%)	7.0	7.0	7.0	7.0	7.0	7.0
5	PH	744	672	744	720	744	720
6	SH	744	672	744	720	744	720
7	RSH	0	0	0	0	0	0
8	UH	0	0	0	0	0	0
9	POH	0	0	0	0	0	0
10	FOH & EFOH	26	23	26	25	26	25
11	MOH & EMOH	26	23	26	25	26	25
12	Oper Mbtu	6,860,331	6,196,428	6,860,331	6,697,374	6,920,615	6,697,374
13	Net Gen (MWH)	623,100	562,800	623,100	587,592	607,178	587,592
14	ANOHR (Btu/KWH)	11,010	11,010	11,010	11,398	11,398	11,398
15	NOF (%)	100.1	100.1	100.1	97.5	97.5	97.5
16	NSC (MW)	837	837	837	837	837	837
17	ANOHR Equation	-149.29 x NOF + 25954					

	Turkey Point 3	Jul '21	Aug '21	Sep '21	Oct '21	Nov '21	Dec '21	Total
1	EAF (%)	93.0	93.0	93.0	24.0	74.4	93.0	85.7
2	EPOF (%)	0.0	0.0	0.0	74.2	20.0	0.0	7.9
3	EUOF (%)	7.0	7.0	7.0	1.8	5.6	7.0	6.4
4	EUOR (%)	7.0	7.0	7.0	7.0	7.0	7.0	6.9
5	PH	744	744	720	744	720	744	8,760
6	SH	744	744	720	192	576	744	8,064
7	RSH	0	0	0	0	0	0	0
8	UH	0	0	0	552	144	0	696
9	POH	0	0	0	552	144	0	696
10	FOH & EFOH	26	26	25	7	20	26	280
11	MOH & EMOH	26	26	25	7	20	26	280
12	Oper Mbtu	6,920,615	6,920,615	6,697,374	1,785,964	5,311,224	6,860,331	74,767,898
13	Net Gen (MWH)	607,178	607,178	587,592	156,691	482,400	623,100	6,655,501
14	ANOHR (Btu/KWH)	11,398	11,398	11,398	11,398	11,010	11,010	11,234
15	NOF (%)	97.5	97.5	97.5	97.5	100.1	100.1	98.6
16	NSC (MW)	837	837	837	837	837	837	837
17	ANOHR Equation	-149.29 x NOF + 25954						

ESTIMATED UNIT PERFORMANCE DATA

FLORIDA POWER & LIGHT

PERIOD OF: JANUARY THROUGH DECEMBER, 2021

	Turkey Point 4	Jan '21	Feb '21	Mar '21	Apr '21	May '21	Jun '21
1	EAF (%)	93.6	93.6	93.6	93.6	93.6	93.6
2	EPOF (%)	0.0	0.0	0.0	0.0	0.0	0.0
3	EUOF (%)	6.4	6.4	6.4	6.4	6.4	6.4
4	EUOR (%)	6.4	6.4	6.4	6.4	6.4	6.4
5	PH	744	672	744	720	744	720
6	SH	744	672	744	720	744	720
7	RSH	0	0	0	0	0	0
8	UH	0	0	0	0	0	0
9	POH	0	0	0	0	0	0
10	FOH & EFOH	24	22	24	23	24	23
11	MOH & EMOH	24	22	24	23	24	23
12	Oper Mbtu	6,817,818	6,158,035	6,817,818	6,454,253	6,669,395	6,454,253
13	Net Gen (MWH)	629,647	568,714	629,647	590,400	610,080	590,400
14	ANOHR (Btu/KWH)	10,828	10,828	10,828	10,932	10,932	10,932
15	NOF (%)	100.6	100.6	100.6	97.5	97.5	97.5
16	NSC (MW)	841	841	841	841	841	841
17	ANOHR Equation	-33.51 x NOF + 14199					

	Turkey Point 4	Jul '21	Aug '21	Sep '21	Oct '21	Nov '21	Dec '21	Total
1	EAF (%)	93.6	93.6	93.6	93.6	93.6	93.6	93.6
2	EPOF (%)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
3	EUOF (%)	6.4	6.4	6.4	6.4	6.4	6.4	6.4
4	EUOR (%)	6.4	6.4	6.4	6.4	6.4	6.4	6.4
5	PH	744	744	720	744	720	744	8,760
6	SH	744	744	720	744	720	744	8,760
7	RSH	0	0	0	0	0	0	0
8	UH	0	0	0	0	0	0	0
9	POH	0	0	0	0	0	0	0
10	FOH & EFOH	24	24	23	24	23	24	280
11	MOH & EMOH	24	24	23	24	23	24	280
12	Oper Mbtu	6,669,395	6,669,395	6,454,253	6,669,395	6,597,890	6,817,818	79,248,428
13	Net Gen (MWH)	610,080	610,080	590,400	610,080	609,336	629,647	7,278,511
14	ANOHR (Btu/KWH)	10,932	10,932	10,932	10,932	10,828	10,828	10,888
15	NOF (%)	97.5	97.5	97.5	97.5	100.6	100.6	98.8
16	NSC (MW)	841	841	841	841	841	841	841
17	ANOHR Equation	-33.51 x NOF + 14199						

ESTIMATED UNIT PERFORMANCE DATA

FLORIDA POWER & LIGHT

PERIOD OF: JANUARY THROUGH DECEMBER, 2021

	Turkey Point 5	Jan '21	Feb '21	Mar '21	Apr '21	May '21	Jun '21
1	EAF (%)	90.5	90.5	29.2	90.5	90.5	90.5
2	EPOF (%)	0.0	0.0	67.7	0.0	0.0	0.0
3	EUOF (%)	9.5	9.5	3.1	9.5	9.5	9.5
4	EUOR (%)	9.5	9.5	9.5	22.2	15.7	9.5
5	PH	744	672	744	720	744	720
6	SH	744	672	240	309	451	720
7	RSH	0	0	0	411	293	0
8	UH	0	0	504	0	0	0
9	POH	0	0	504	0	0	0
10	FOH & EFOH	36	32	12	35	36	35
11	MOH & EMOH	35	32	11	34	35	34
12	Oper Mbtu	2,450,156	2,513,048	1,111,578	1,798,814	2,081,146	3,273,329
13	Net Gen (MWH)	325,732	336,960	151,772	252,076	284,038	446,140
14	ANOHR (Btu/KWH)	7,522	7,458	7,324	7,136	7,327	7,337
15	NOF (%)	34.9	39.9	50.3	64.9	50.1	49.3
16	NSC (MW)	1,256	1,256	1,256	1,256	1,256	1,256
17	ANOHR Equation	-12.88 x NOF + 7972					

	Turkey Point 5	Jul '21	Aug '21	Sep '21	Oct '21	Nov '21	Dec '21	Total
1	EAF (%)	90.5	90.5	90.5	90.5	65.0	60.5	80.6
2	EPOF (%)	0.0	0.0	0.0	0.0	28.2	33.1	10.9
3	EUOF (%)	9.5	9.5	9.5	9.5	6.8	6.4	8.5
4	EUOR (%)	9.5	9.5	9.5	32.3	45.2	8.6	12.0
5	PH	744	744	720	744	720	744	8,760
6	SH	744	744	720	220	109	552	6,225
7	RSH	0	0	0	524	563	0	1791
8	UH	0	0	0	0	48	192	744
9	POH	0	0	0	0	48	192	744
10	FOH & EFOH	36	36	35	36	25	24	377
11	MOH & EMOH	35	35	34	35	24	23	368
12	Oper Mbtu	3,564,292	3,577,302	3,441,889	1,442,689	608,261	1,825,693	27,783,412
13	Net Gen (MWH)	488,393	490,310	471,427	205,687	84,775	242,746	3,780,056
14	ANOHR (Btu/KWH)	7,298	7,296	7,301	7,014	7,175	7,521	7,350
15	NOF (%)	52.3	52.5	52.1	74.4	61.9	35.0	48.3
16	NSC (MW)	1,256	1,256	1,256	1,256	1,256	1,256	1,256
17	ANOHR Equation	-12.88 x NOF + 7972						

ESTIMATED UNIT PERFORMANCE DATA

FLORIDA POWER & LIGHT

PERIOD OF: JANUARY THROUGH DECEMBER, 2021

	West County 1	Jan '21	Feb '21	Mar '21	Apr '21	May '21	Jun '21
1	EAF (%)	93.5	93.5	93.5	93.5	93.5	93.5
2	EPOF (%)	0.0	0.0	0.0	0.0	0.0	0.0
3	EUOF (%)	6.5	6.5	6.5	6.5	6.5	6.5
4	EUOR (%)	6.9	6.5	6.5	6.5	6.5	6.5
5	PH	744	672	744	720	744	720
6	SH	703	672	744	720	744	720
7	RSH	41	0	0	0	0	0
8	UH	0	0	0	0	0	0
9	POH	0	0	0	0	0	0
10	FOH & EFOH	15	14	15	15	15	15
11	MOH & EMOH	33	30	33	32	33	32
12	Oper Mbtu	3,262,025	3,620,448	4,707,638	4,993,325	5,081,209	4,800,834
13	Net Gen (MWH)	450,992	504,592	663,141	708,273	719,922	678,947
14	ANOHR (Btu/KWH)	7,233	7,175	7,099	7,050	7,058	7,071
15	NOF (%)	52.5	61.4	72.9	80.4	79.1	77.1
16	NSC (MW)	1,223	1,223	1,223	1,223	1,223	1,223
17	ANOHR Equation	-6.57 x NOF + 7578					

	West County 1	Jul '21	Aug '21	Sep '21	Oct '21	Nov '21	Dec '21	Total
1	EAF (%)	93.5	93.5	93.5	63.3	93.5	93.5	91.0
2	EPOF (%)	0.0	0.0	0.0	32.3	0.0	0.0	2.7
3	EUOF (%)	6.5	6.5	6.5	4.4	6.5	6.5	6.3
4	EUOR (%)	6.5	6.5	6.5	6.6	6.5	6.5	6.5
5	PH	744	744	720	744	720	744	8,760
6	SH	744	744	720	498	720	742	8,471
7	RSH	0	0	0	6	0	2	49
8	UH	0	0	0	240	0	0	240
9	POH	0	0	0	240	0	0	240
10	FOH & EFOH	15	15	15	10	15	15	175
11	MOH & EMOH	33	33	32	22	32	33	377
12	Oper Mbtu	5,287,182	5,445,680	5,315,587	3,565,575	4,014,416	3,514,069	53,700,856
13	Net Gen (MWH)	751,554	775,959	758,070	507,122	560,751	486,309	7,565,632
14	ANOHR (Btu/KWH)	7,035	7,018	7,012	7,031	7,159	7,226	7,098
15	NOF (%)	82.6	85.3	86.1	83.3	63.7	53.6	73.0
16	NSC (MW)	1,223	1,223	1,223	1,223	1,223	1,223	1,223
17	ANOHR Equation	-6.57 x NOF + 7578						

ESTIMATED UNIT PERFORMANCE DATA

FLORIDA POWER & LIGHT

PERIOD OF: JANUARY THROUGH DECEMBER, 2021

	West County 2	Jan '21	Feb '21	Mar '21	Apr '21	May '21	Jun '21
1	EAF (%)	92.2	92.2	62.4	92.2	92.2	92.2
2	EPOF (%)	0.0	0.0	32.3	0.0	0.0	0.0
3	EUOF (%)	7.8	7.8	5.3	7.8	7.8	7.8
4	EUOR (%)	7.8	7.8	7.8	7.8	7.8	7.8
5	PH	744	672	744	720	744	720
6	SH	744	672	504	720	744	720
7	RSH	0	0	0	0	0	0
8	UH	0	0	240	0	0	0
9	POH	0	0	240	0	0	0
10	FOH & EFOH	15	14	10	15	15	15
11	MOH & EMOH	43	39	29	41	43	41
12	Oper Mbtu	4,309,351	4,188,656	3,321,497	5,037,509	5,041,713	5,037,266
13	Net Gen (MWH)	618,360	604,860	482,145	735,725	733,767	735,582
14	ANOHR (Btu/KWH)	6,969	6,925	6,889	6,847	6,871	6,848
15	NOF (%)	68.0	73.6	78.2	83.6	80.6	83.5
16	NSC (MW)	1,223	1,223	1,223	1,223	1,223	1,223
17	ANOHR Equation	-7.77 x NOF + 7497					

	West County 2	Jul '21	Aug '21	Sep '21	Oct '21	Nov '21	Dec '21	Total
1	EAF (%)	92.2	92.2	92.2	92.2	92.2	92.2	89.7
2	EPOF (%)	0.0	0.0	0.0	0.0	0.0	0.0	2.7
3	EUOF (%)	7.8	7.8	7.8	7.8	7.8	7.8	7.6
4	EUOR (%)	7.8	7.8	7.8	7.8	7.8	7.8	7.8
5	PH	744	744	720	744	720	744	8,760
6	SH	744	744	720	744	720	744	8,520
7	RSH	0	0	0	0	0	0	0
8	UH	0	0	0	0	0	0	240
9	POH	0	0	0	0	0	0	240
10	FOH & EFOH	15	15	15	15	15	15	175
11	MOH & EMOH	43	43	41	43	41	43	491
12	Oper Mbtu	5,350,933	5,366,512	5,233,013	5,468,353	4,427,414	3,950,576	56,789,899
13	Net Gen (MWH)	783,675	786,187	767,304	802,753	638,508	563,081	8,251,947
14	ANOHR (Btu/KWH)	6,828	6,826	6,820	6,812	6,934	7,016	6,882
15	NOF (%)	86.1	86.4	87.1	88.2	72.5	61.9	79.2
16	NSC (MW)	1,223	1,223	1,223	1,223	1,223	1,223	1,223
17	ANOHR Equation	-7.77 x NOF + 7497						

ESTIMATED UNIT PERFORMANCE DATA

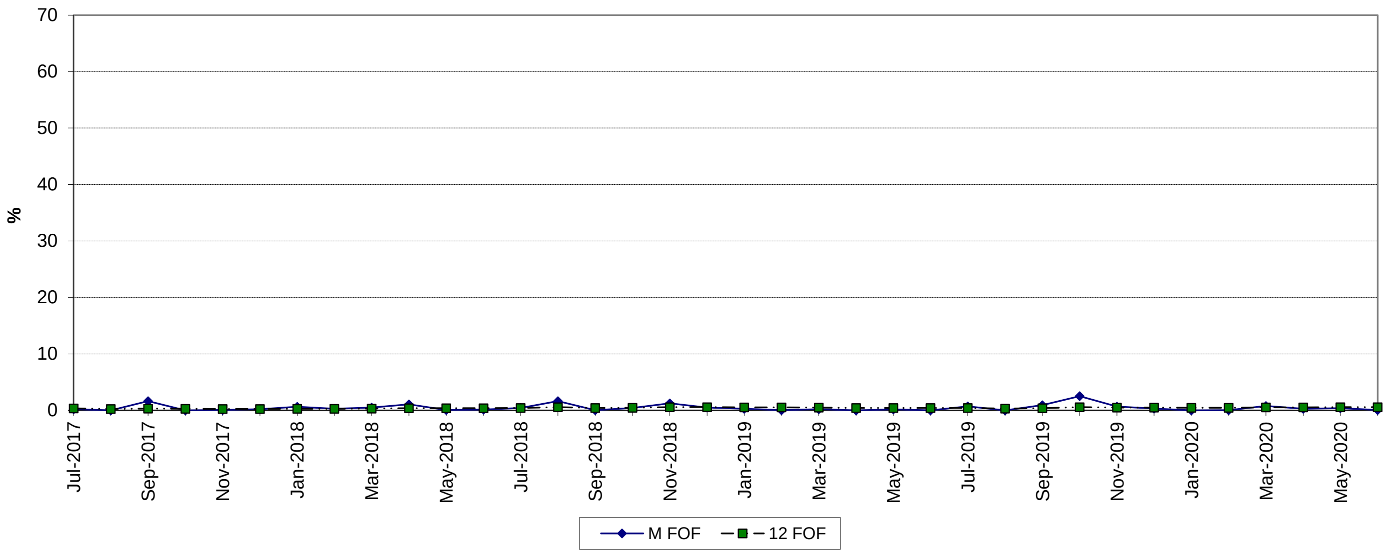
FLORIDA POWER & LIGHT

PERIOD OF: JANUARY THROUGH DECEMBER, 2021

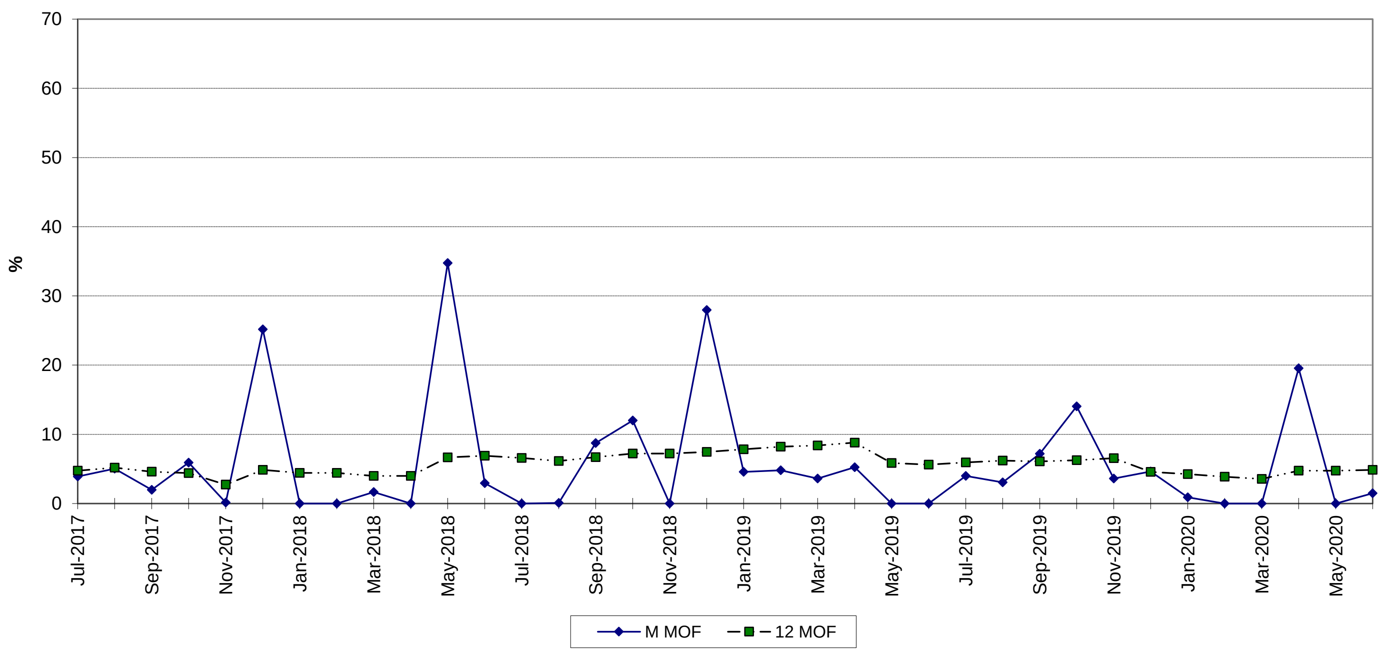
	West County 3	Jan '21	Feb '21	Mar '21	Apr '21	May '21	Jun '21
1	EAF (%)	91.5	76.2	61.1	86.4	91.5	91.5
2	EPOF (%)	0.0	16.7	33.3	5.6	0.0	0.0
3	EUOF (%)	8.5	7.1	5.6	8.0	8.5	8.5
4	EUOR (%)	8.5	7.1	5.6	8.0	8.5	8.5
5	PH	744	672	744	720	744	720
6	SH	744	672	744	720	744	720
7	RSH	0	0	0	0	0	0
8	UH	0	0	0	0	0	0
9	POH	0	0	0	0	0	0
10	FOH & EFOH	16	12	11	15	16	16
11	MOH & EMOH	47	35	31	43	47	45
12	Oper Mbtu	4,146,547	3,657,954	3,723,918	4,825,878	5,252,929	5,156,939
13	Net Gen (MWH)	593,891	523,088	529,718	701,130	766,739	753,718
14	ANOHR (Btu/KWH)	6,982	6,993	7,030	6,883	6,851	6,842
15	NOF (%)	65.0	63.4	58.0	79.3	83.9	85.2
16	NSC (MW)	1,228	1,228	1,228	1,228	1,228	1,228
17	ANOHR Equation	-6.9 x NOF + 7430					

	West County 3	Jul '21	Aug '21	Sep '21	Oct '21	Nov '21	Dec '21	Total
1	EAF (%)	91.5	91.5	91.5	85.6	61.1	77.7	83.2
2	EPOF (%)	0.0	0.0	0.0	6.5	33.3	15.1	9.1
3	EUOF (%)	8.5	8.5	8.5	7.9	5.6	7.2	7.7
4	EUOR (%)	8.5	8.5	8.5	7.9	5.6	7.2	7.7
5	PH	744	744	720	744	720	744	8,760
6	SH	744	744	720	744	720	744	8,760
7	RSH	0	0	0	0	0	0	0
8	UH	0	0	0	0	0	0	0
9	POH	0	0	0	0	0	0	0
10	FOH & EFOH	16	16	16	15	11	14	175
11	MOH & EMOH	47	47	45	44	30	40	499
12	Oper Mbtu	5,354,670	5,385,399	5,223,137	5,107,072	3,486,343	3,714,365	55,146,319
13	Net Gen (MWH)	782,961	787,915	764,287	743,604	494,938	528,284	7,970,273
14	ANOHR (Btu/KWH)	6,839	6,835	6,834	6,868	7,044	7,031	6,919
15	NOF (%)	85.7	86.2	86.4	81.4	56.0	57.8	74.1
16	NSC (MW)	1,228	1,228	1,228	1,228	1,228	1,228	1,228
17	ANOHR Equation	-6.9 x NOF + 7430						

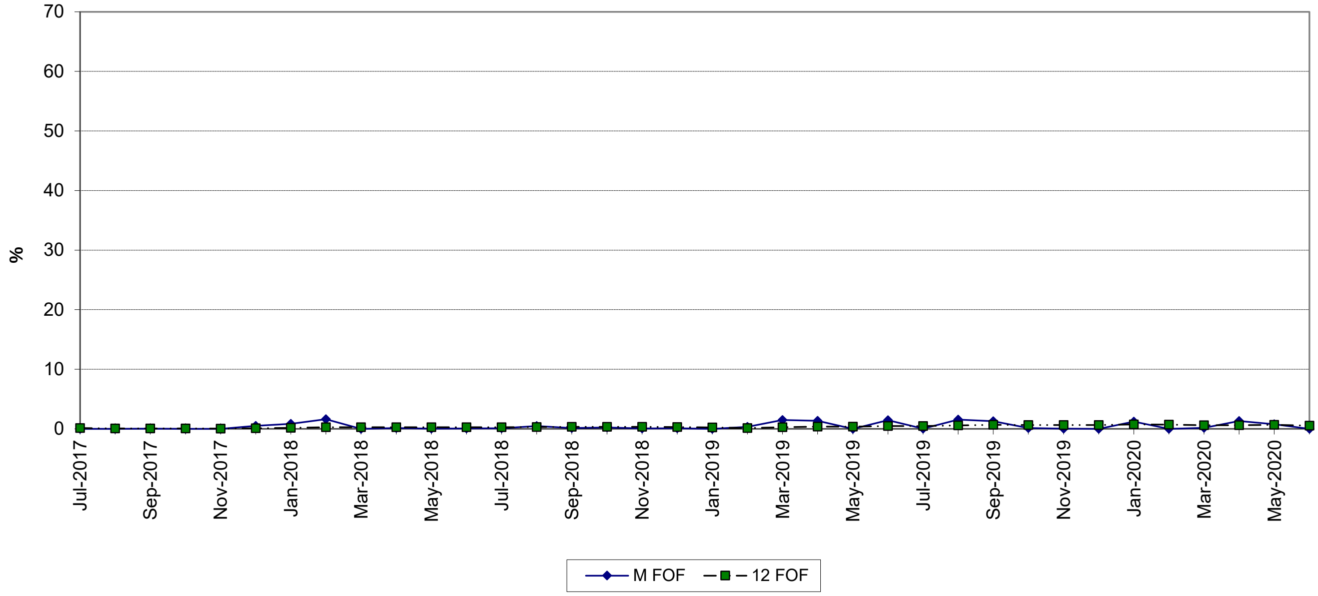
CAPE CANAVERAL 3
FORCED OUTAGE FACTOR



MAINTENANCE OUTAGE FACTOR



FT. MYERS 2
FORCED OUTAGE FACTOR



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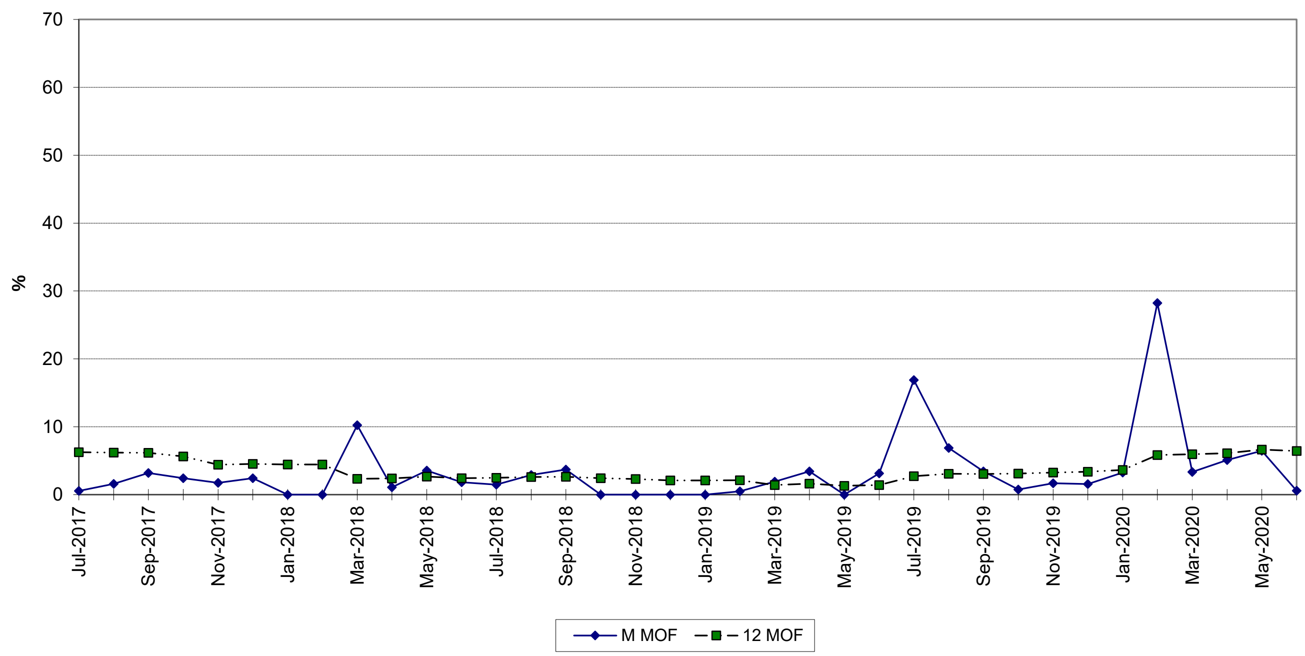
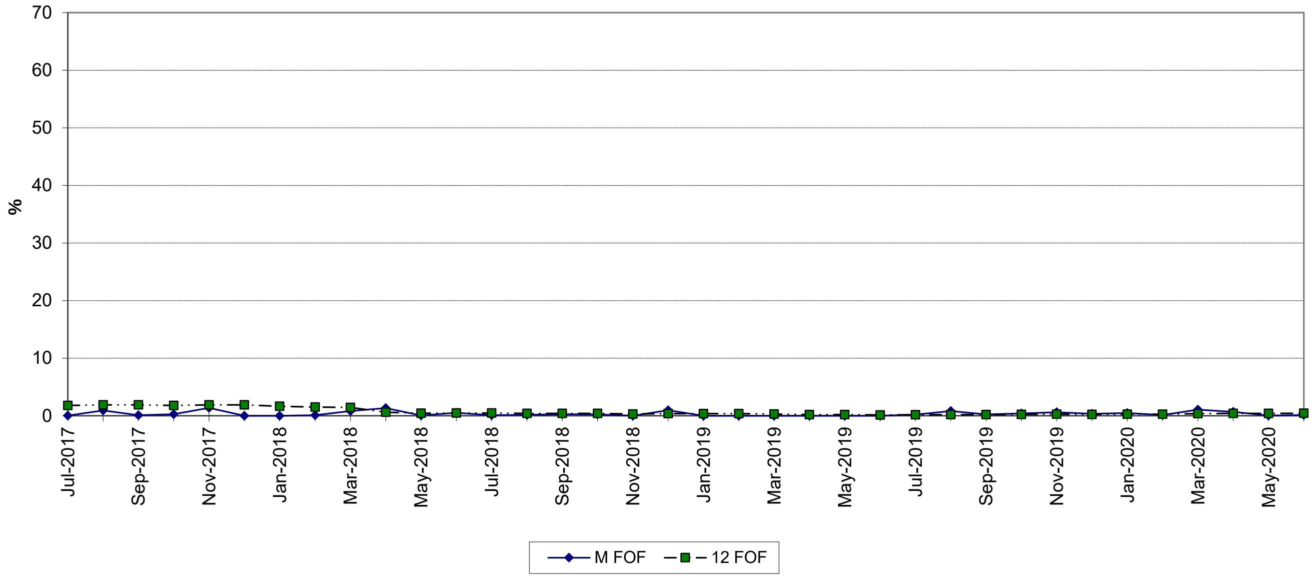


SANFORD 5
FORCED OUTAGE FACTOR



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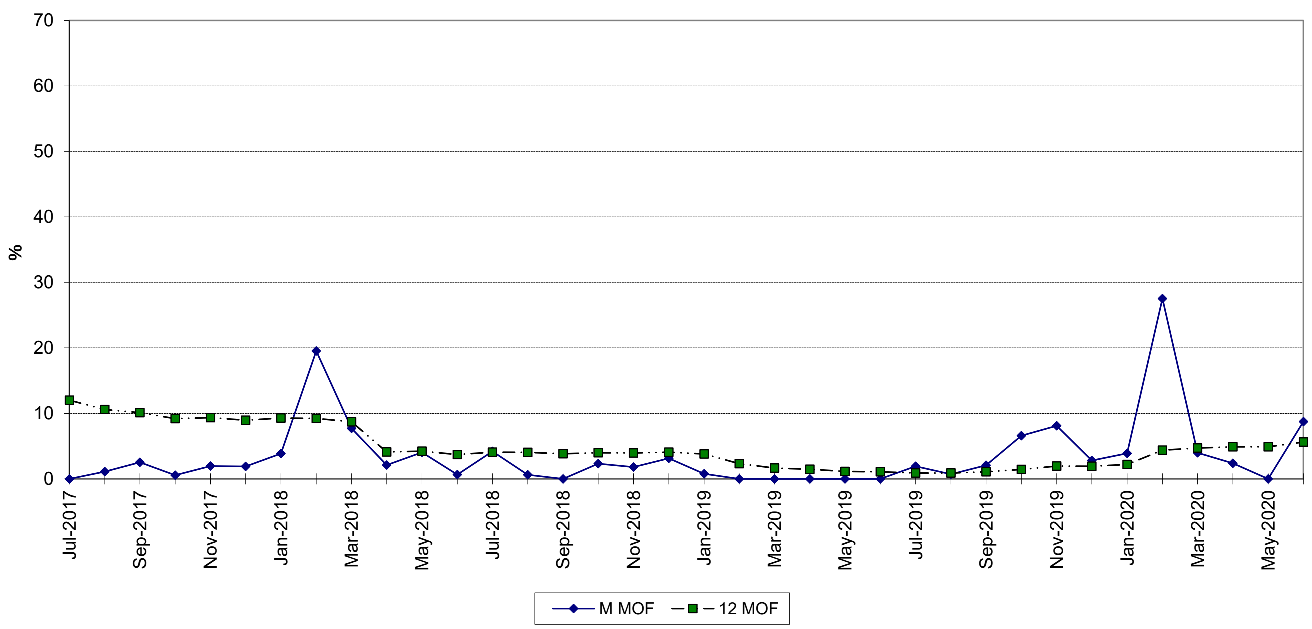

PORT EVERGLADES 5
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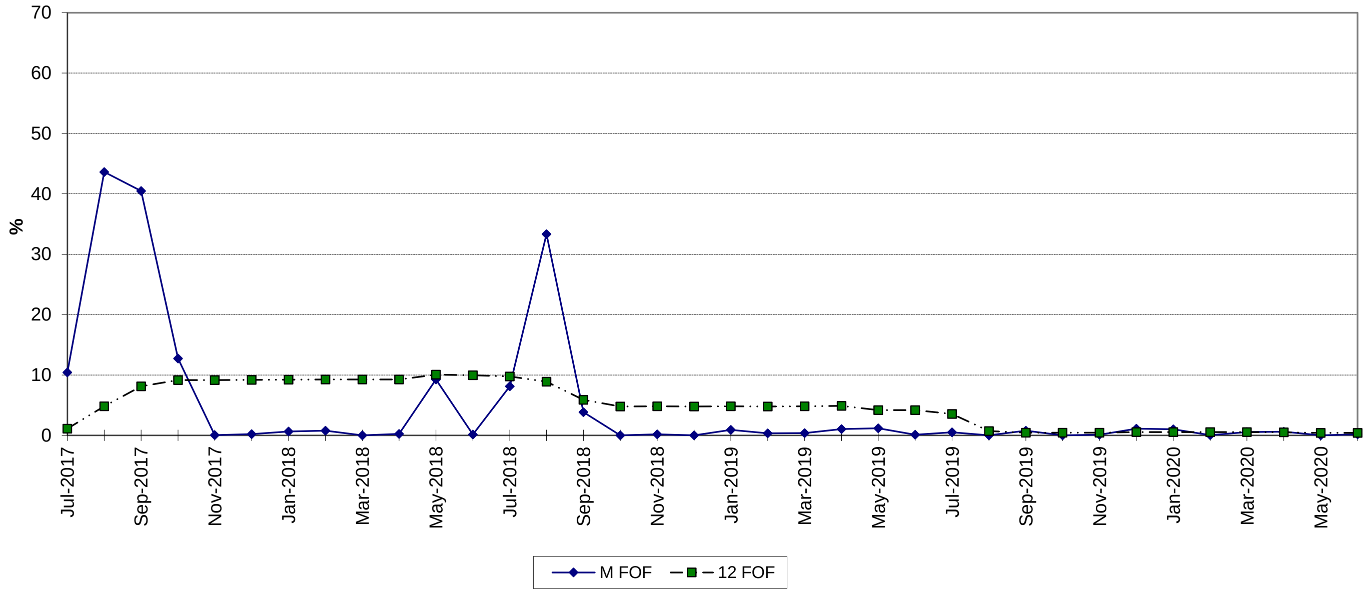

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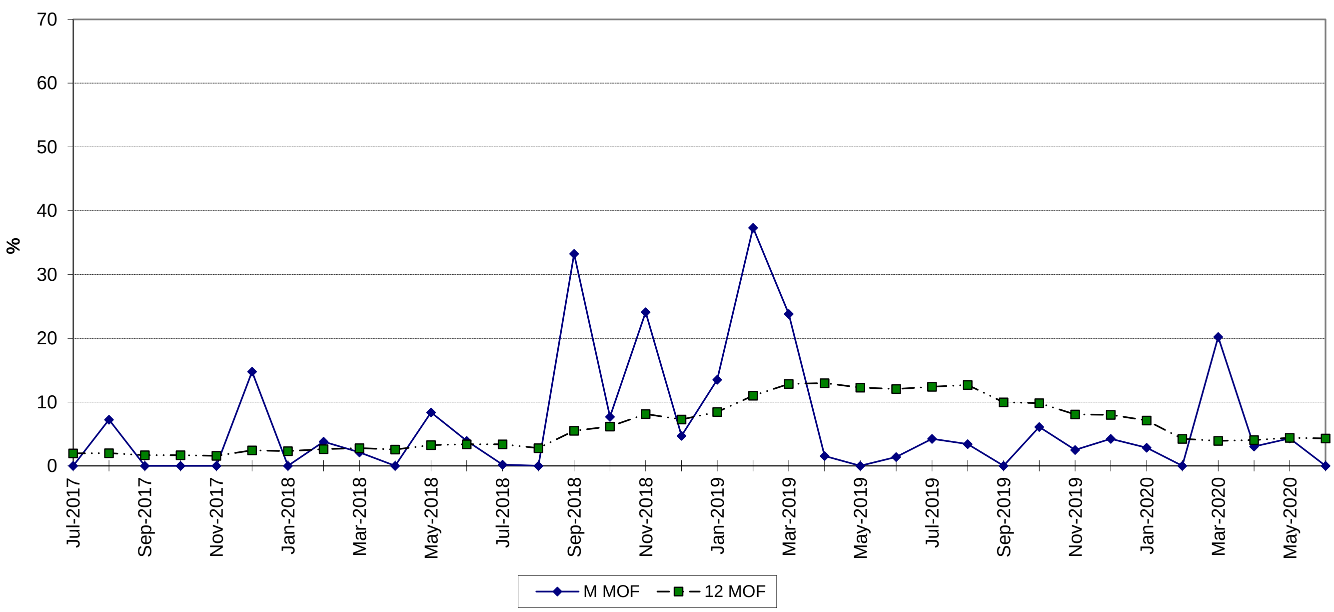
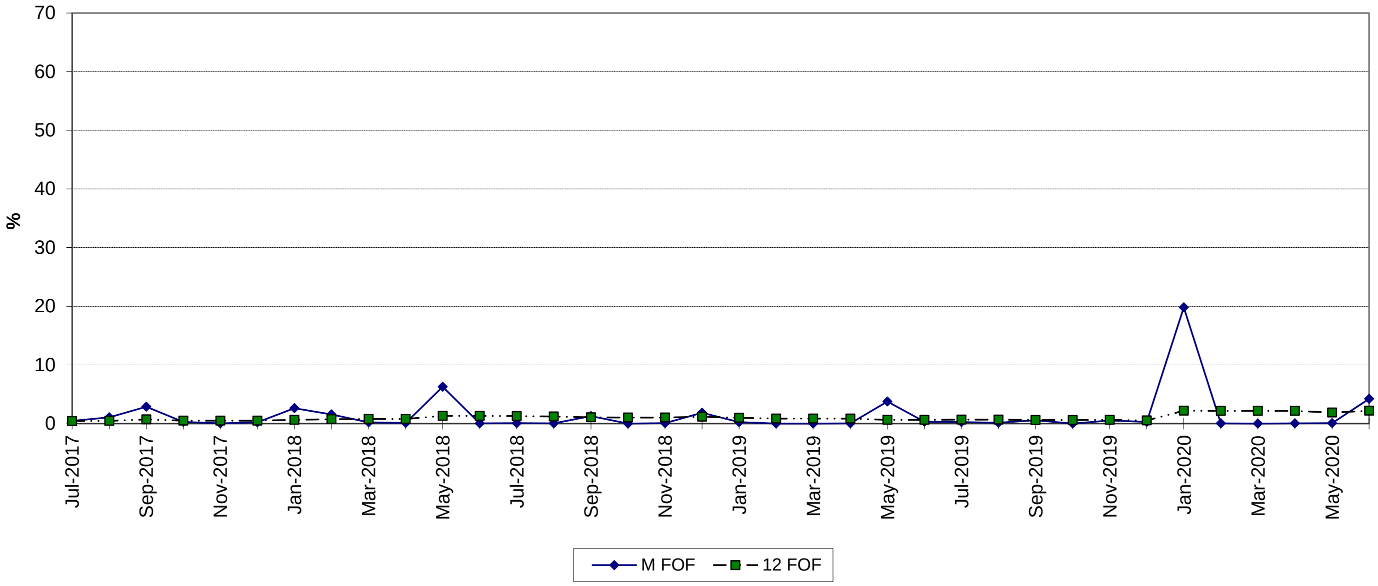


RIVIERA 5
FORCED OUTAGE FACTOR



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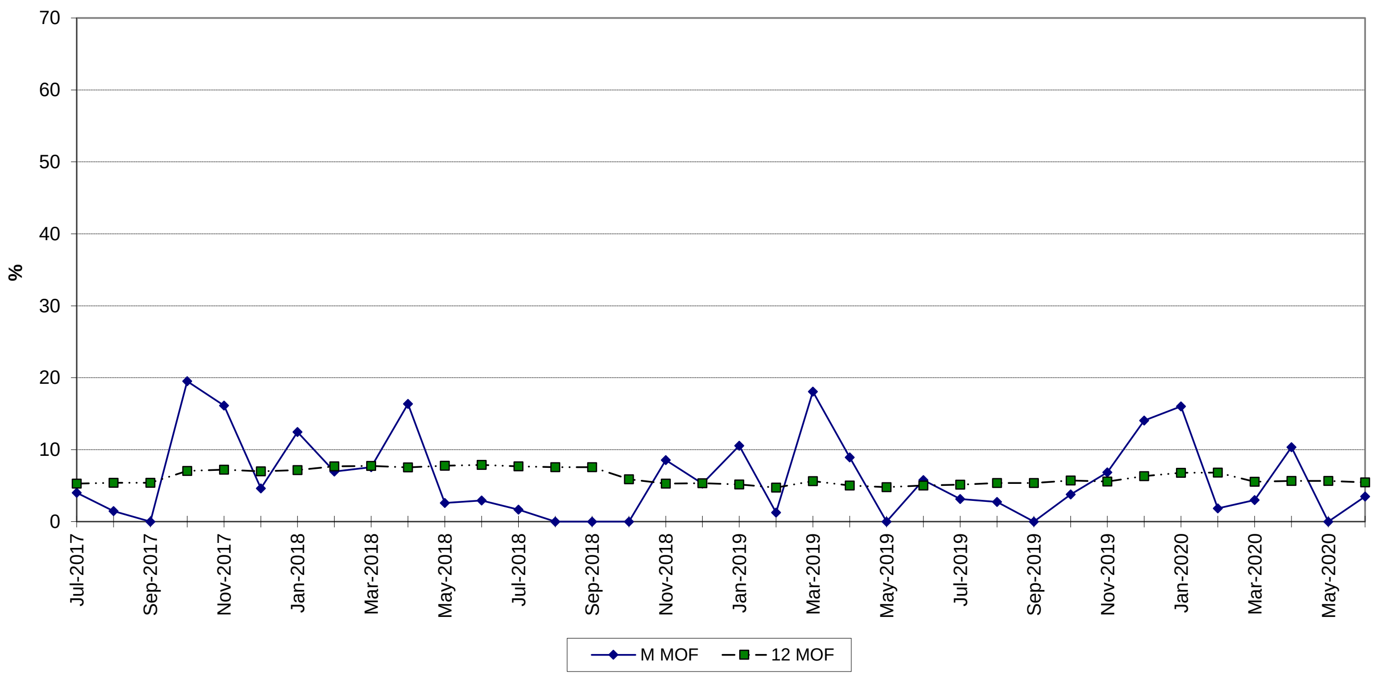

ST. LUCIE 1
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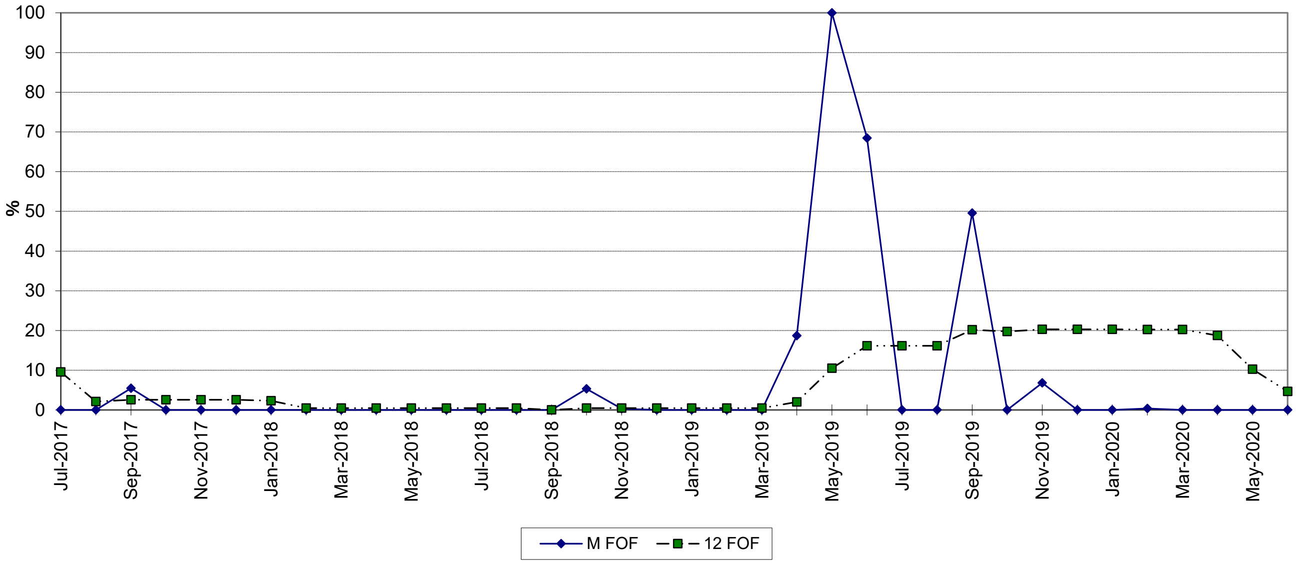

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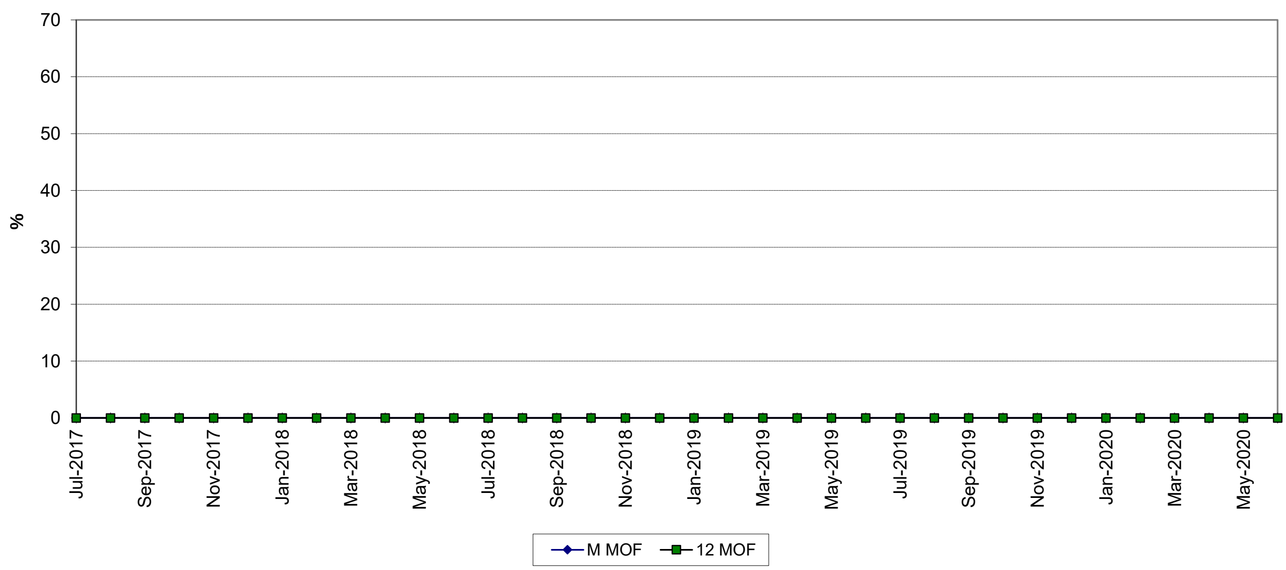

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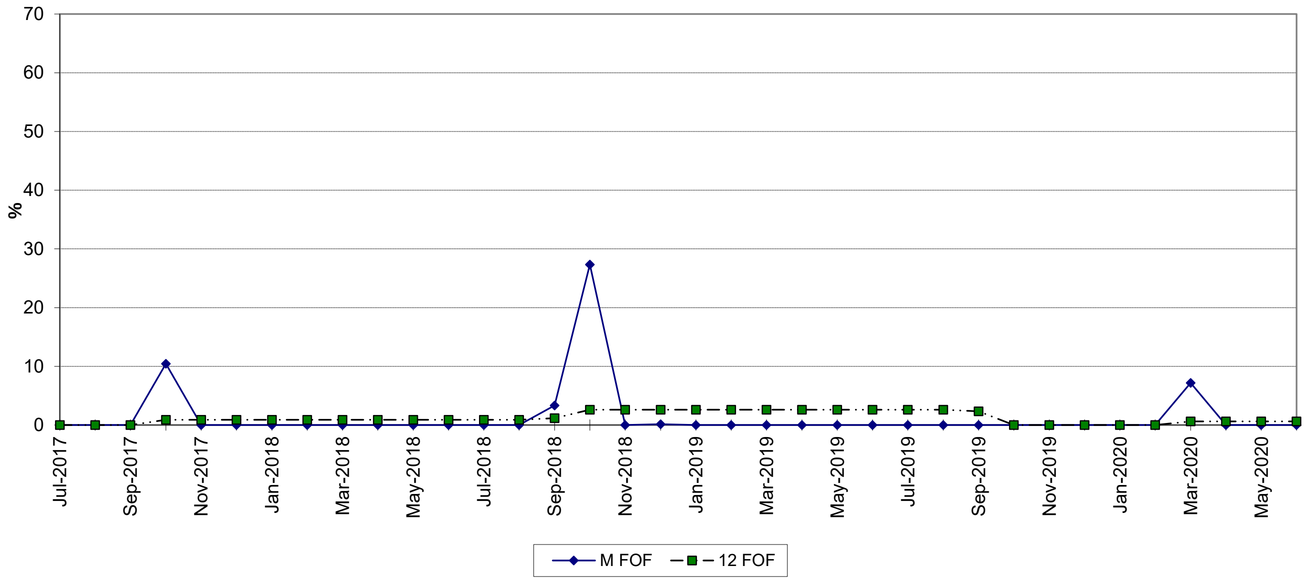

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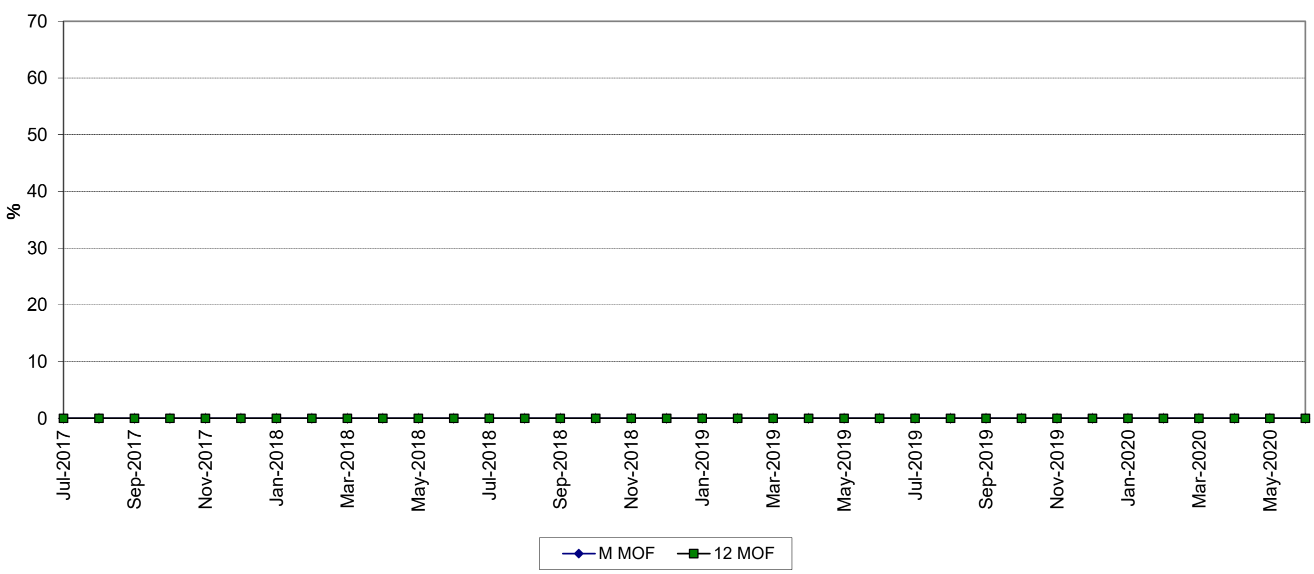
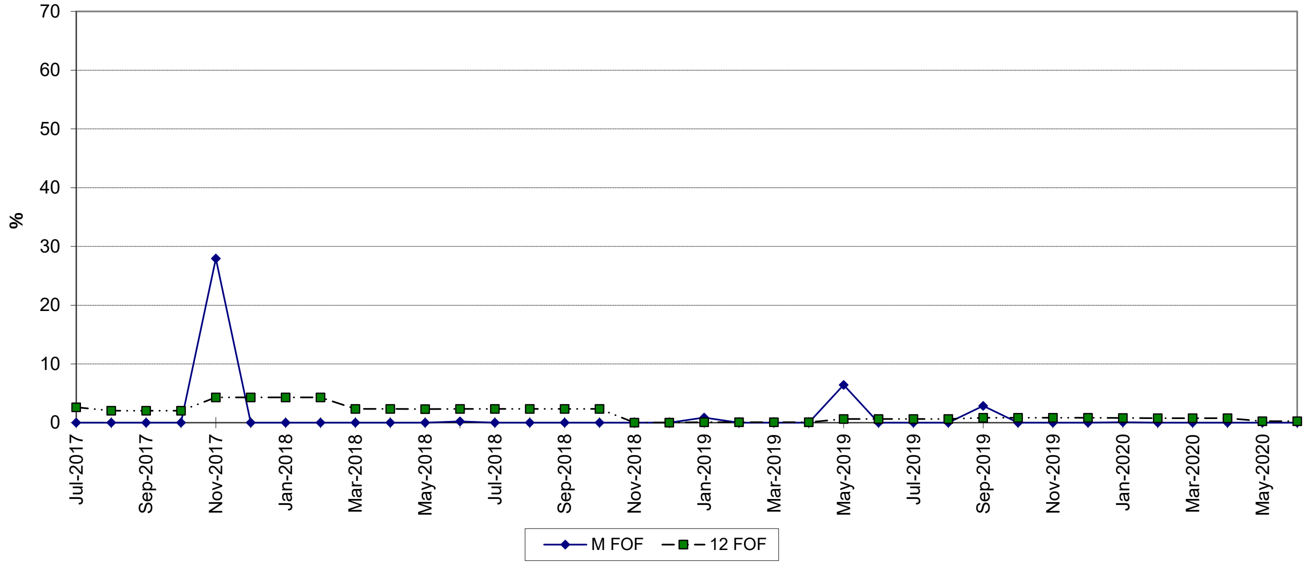


TURKEY POINT 3
FORCED OUTAGE FACTOR



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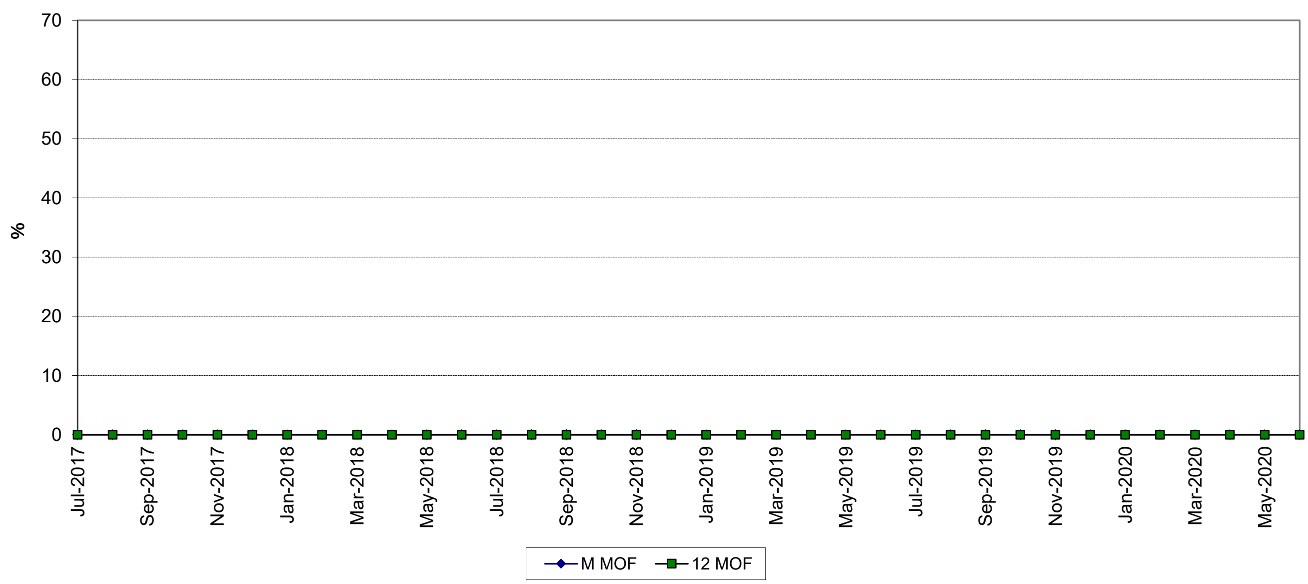

TURKEY POINT 4
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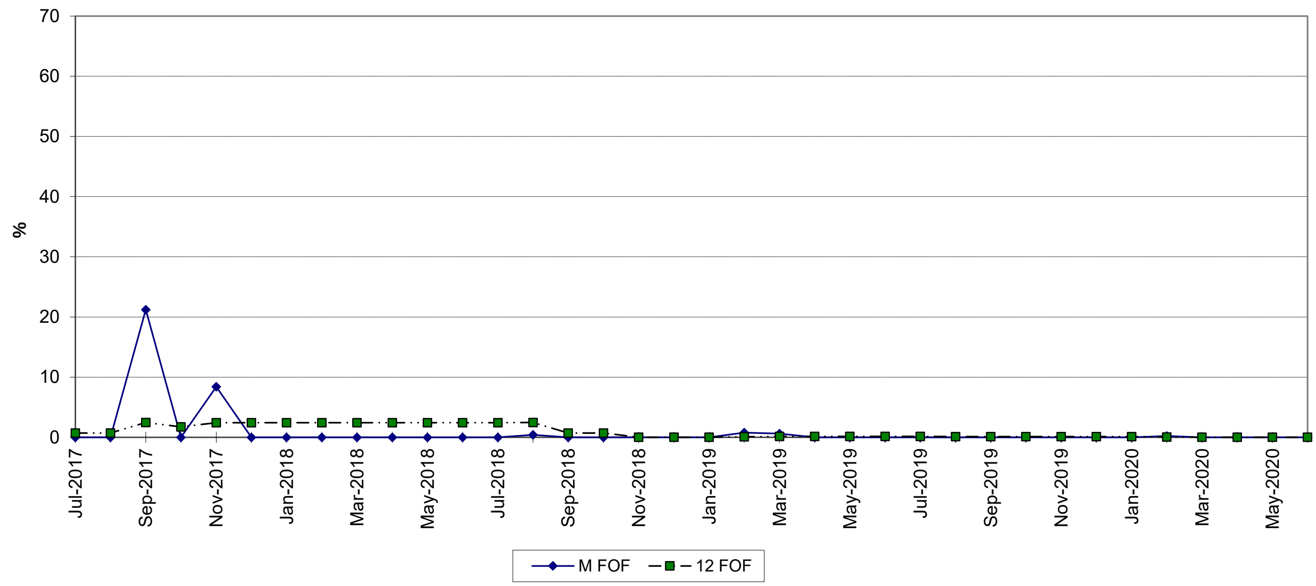

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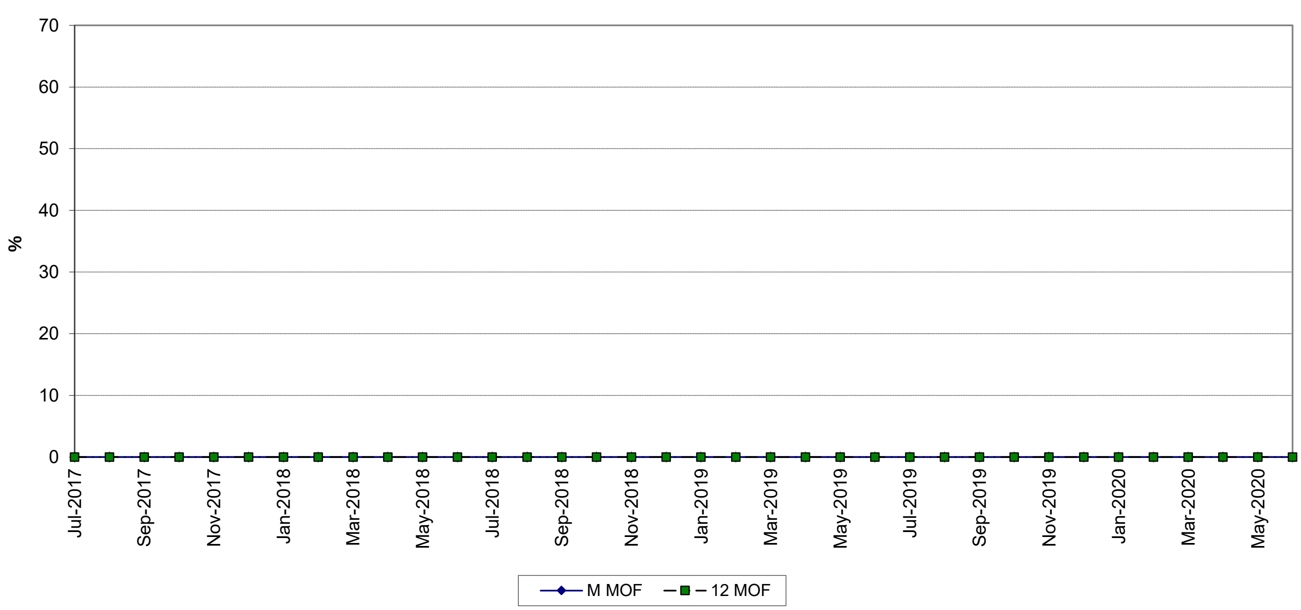
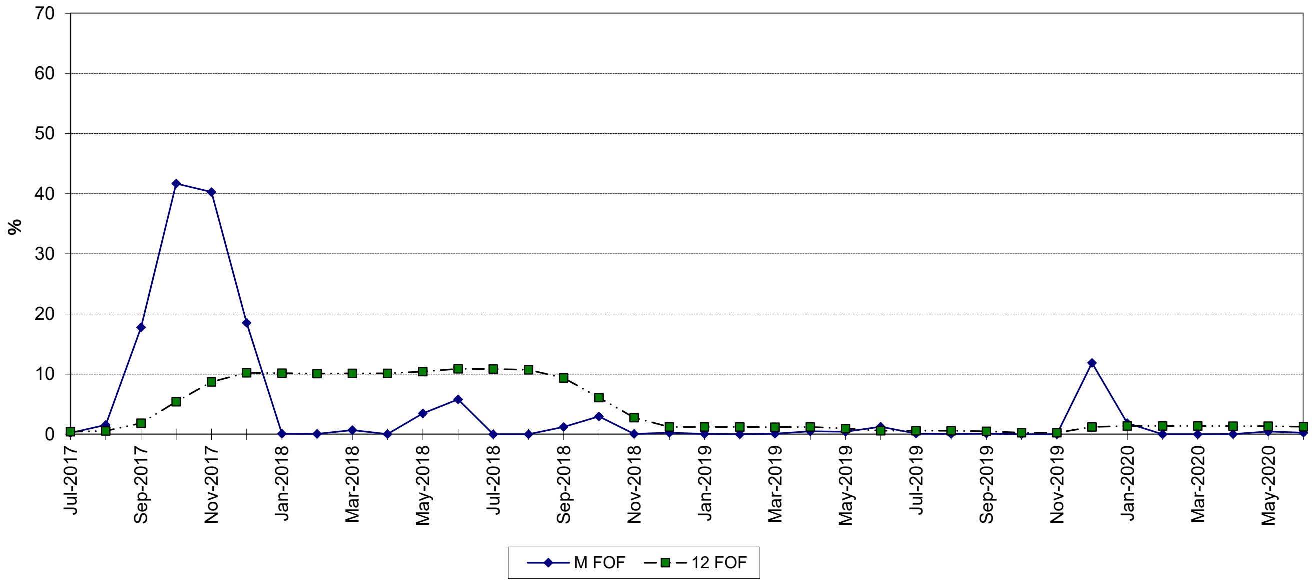


Issued by: Florida Power & Light Company

CRR-2
DOCKET NO. 20200001-EI
FPL Witness: Charles R. Rote
Exhibit No. _______________
Page 31 of 36

TURKEY POINT 5
FORCED OUTAGE FACTOR



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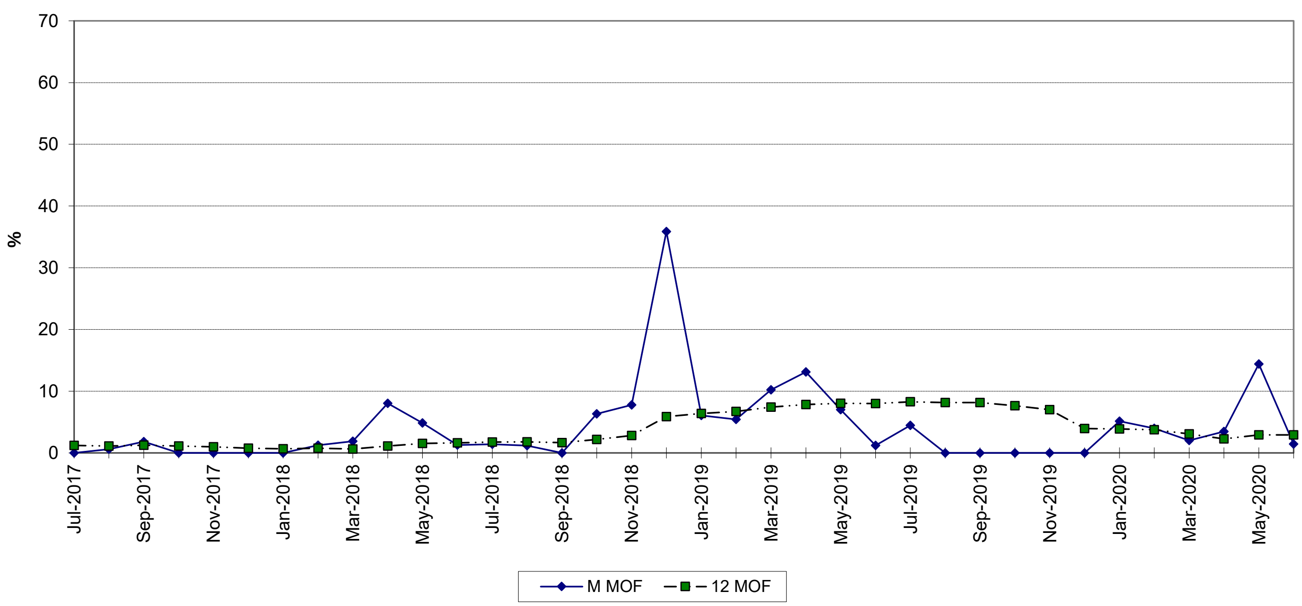
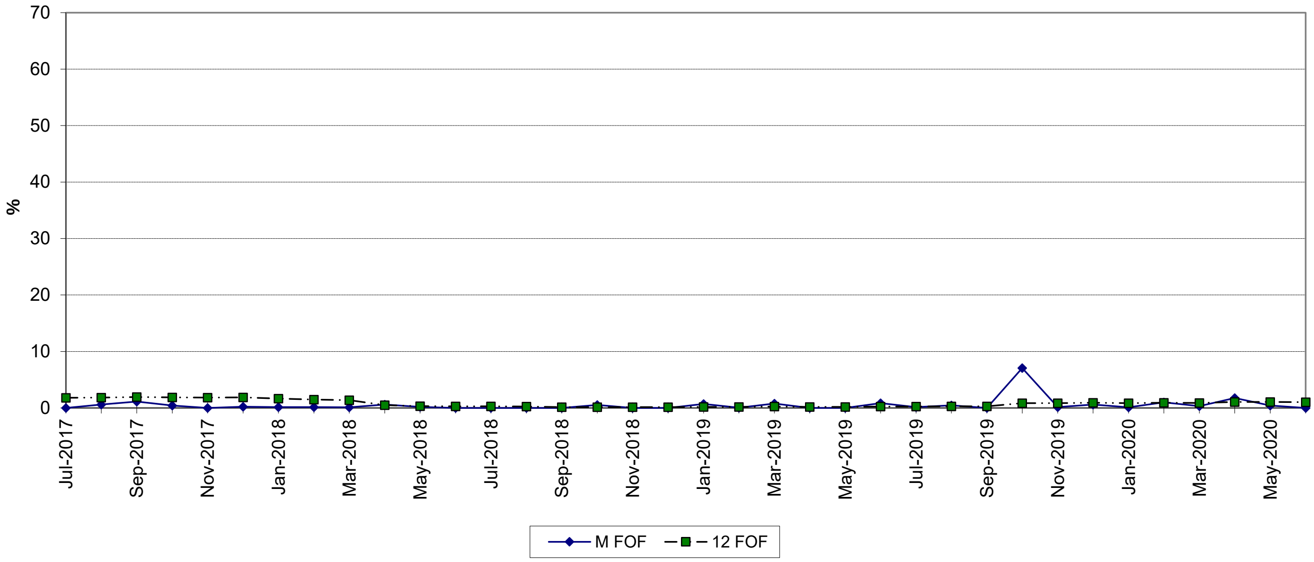
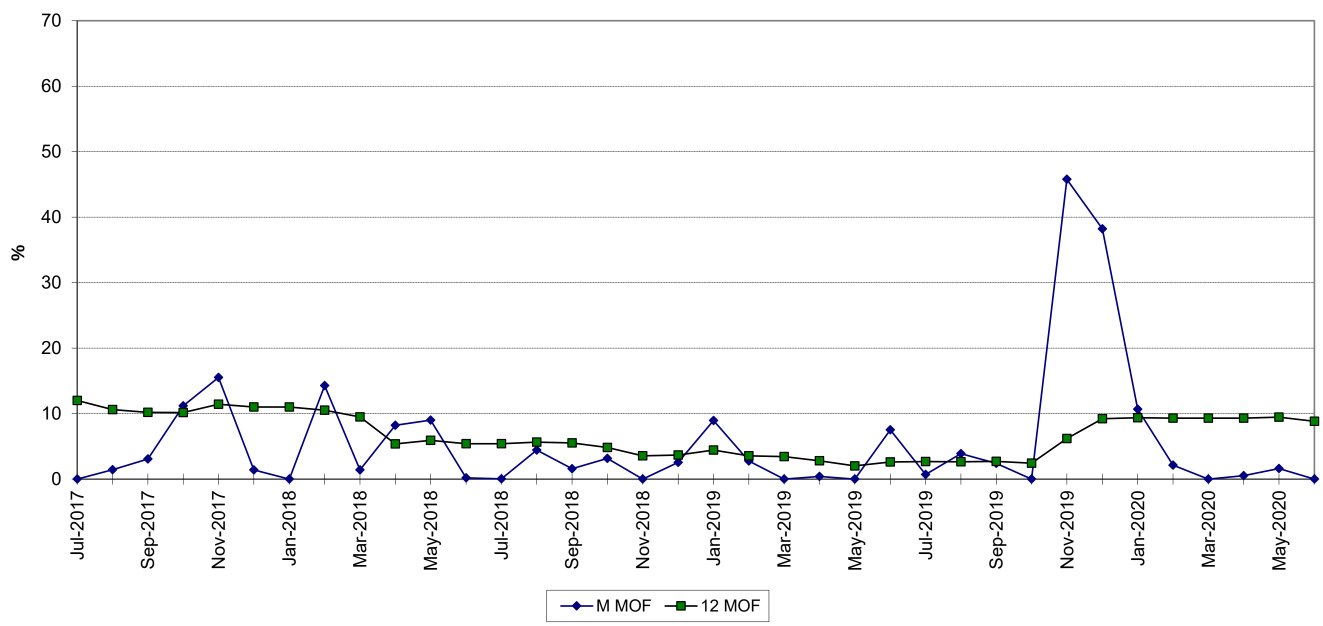


WEST COUNTY 1
FORCED OUTAGE FACTOR



MAINTENANCE OUTAGE FACTOR



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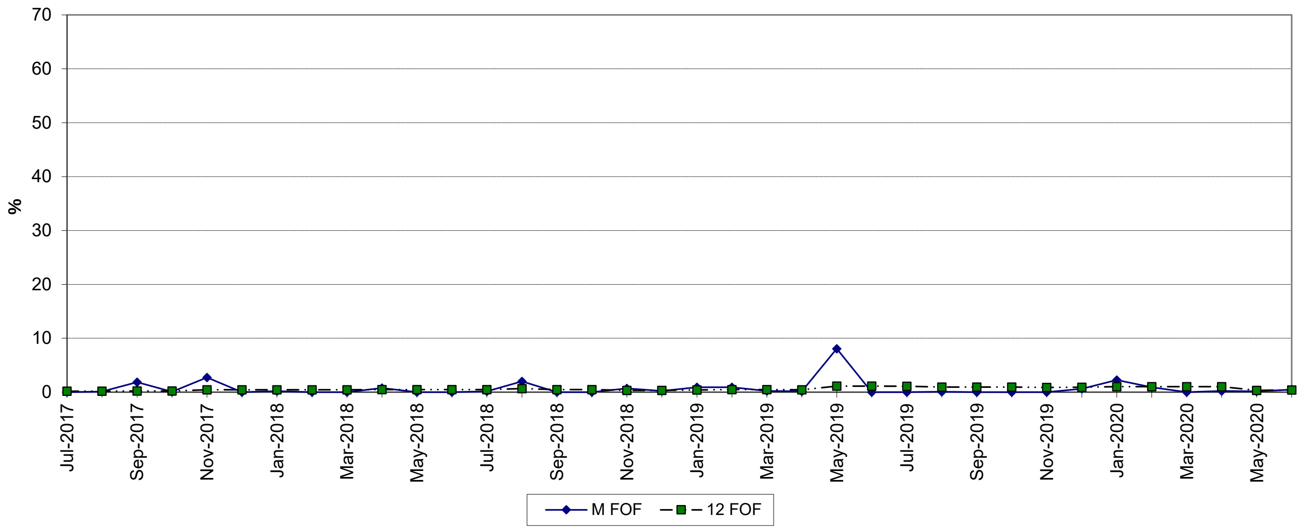
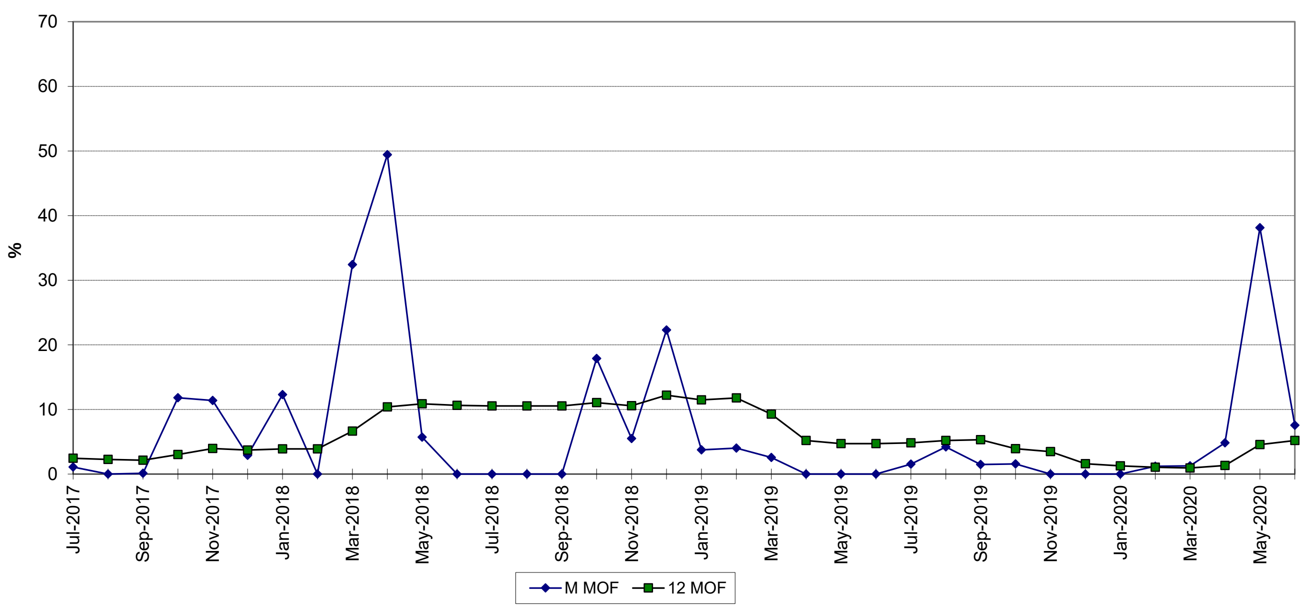
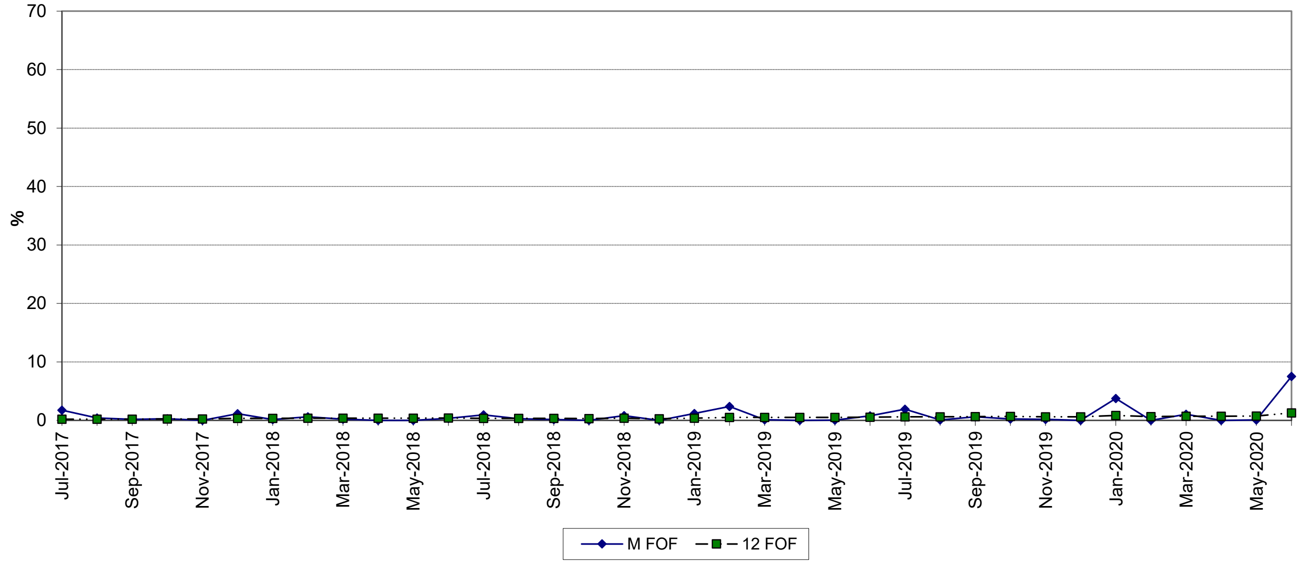


MAINTENANCE OUTAGE FACTOR



WEST COUNTY 3
FORCED OUTAGE FACTOR



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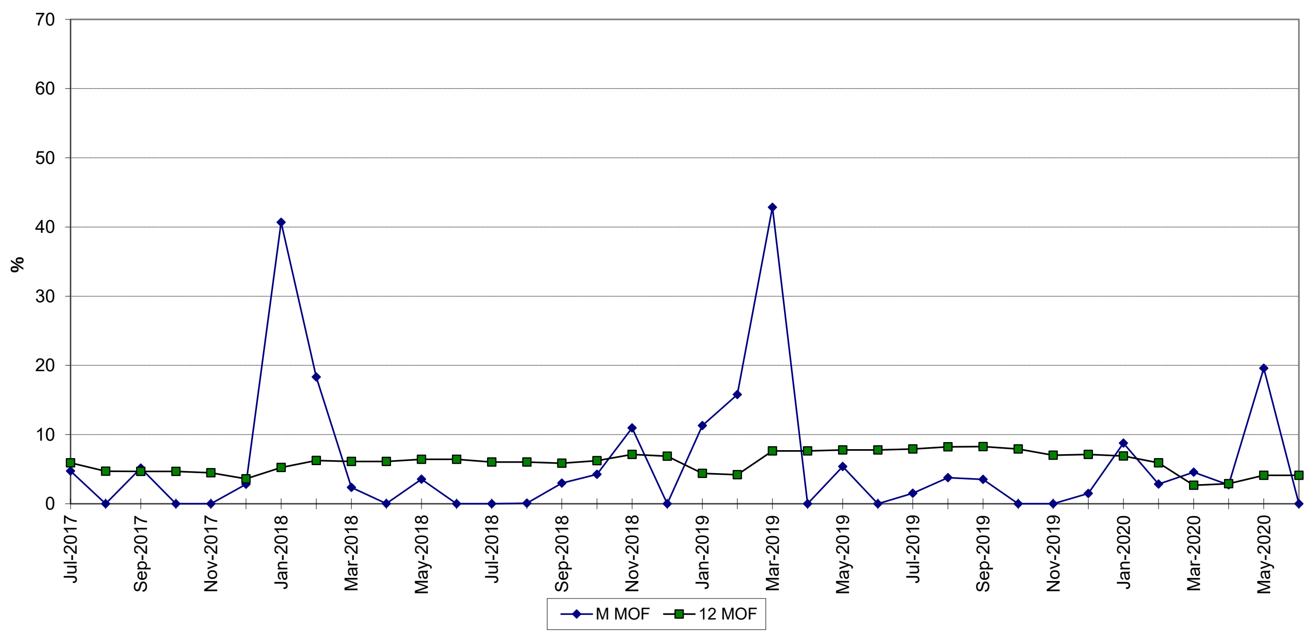

PLANNED OUTAGE SCHEDULE (ESTIMATED)

FLORIDA POWER & LIGHT COMPANY

PERIOD OF: JANUARY THROUGH DECEMBER, 2021

PLANT/UNIT	PLAN OUTAGE			REASON FOR OUTAGE	LR MW*
Cape Canaveral 3	02/16/2021	-	02/25/2021	PCC33-MAINTENANCE-ANNUAL-RELIABILITY	442
Cape Canaveral 3	11/15/2021	-	11/24/2021	PCC32-MAINTENANCE-ANNUAL	442
Cape Canaveral 3	11/29/2021	-	12/08/2021	PCC31-MAINTENANCE-ANNUAL-RELIABILITY	442
Ft. Myers 2	02/27/2021	-	03/05/2021	PFM2ST-MAINTENANCE-OVERHAUL	1,770
Ft. Myers 2	10/23/2021	-	10/29/2021	PFM2B & PFM2C-MAINTENANCE-ANNUAL-RELIABILITY	577
Ft. Myers 2	10/31/2021	-	11/13/2021	PFM2F-MAINTENANCE-ANNUAL & PFM2A-GENERATOR-MINOR	590
Ft. Myers 2	11/07/2021	-	11/13/2021	PFM2E-MAINTENANCE-ANNUAL	295
Ft. Myers 2	11/15/2021	-	11/21/2021	PFM2D-MAINTENANCE-ANNUAL-RELIABILITY	295
Sanford 5	03/20/2021	-	04/02/2021	PSN5-MAINTENANCE-ANNUAL-MANDATORY PMS; PSN5B&C-GEN-MINOR-HRSG-BALANCE OF PLANT (BOP); PSN5A-HRSG-MINOR-BOP; PSN5D-GEN-MINOR-BOP	1,192
Port Everglades 5	03/22/2021	-	04/10/2021	PPE5-MAINTENANCE-NERC CIP & PPE51-53-MAINTENANCE-ANNUAL-RELIABILITY	1,283
Riviera 5	04/03/2021	-	04/30/2021	PRV5-ST VALVES-GEN MINOR & PRV51-53-CT-COMBUSTOR INSPECTION-HRSG WORK	1,308
St. Lucie 1	04/10/2021	-	05/14/2021	REFUELING	981
St. Lucie 2	08/28/2021	-	10/02/2021	REFUELING	840
Turkey Point 3	10/09/2021	-	11/07/2021	REFUELING	837
Turkey Point 4		NONE			
Turkey Point 5	03/01/2021	-	03/21/2021	PTF5-TERMINAL-FUEL PROJECT	1,294
Turkey Point 5	11/09/2021	-	11/21/2021	PTF5A-MAINTENANCE-ANNUAL	324
Turkey Point 5	11/12/2021	-	11/24/2021	PTF5C-MAINTENANCE-ANNUAL	324
Turkey Point 5	11/29/2021	-	12/08/2021	PTF5-ST & 5B MAINTENANCE-ANNUAL	1,294
Turkey Point 5	12/02/2021	-	12/14/2021	PTF5D-MAINTENANCE-ANNUAL	324
West County 1	10/01/2021	-	10/10/2021	PWC1-MAINTENANCE-ANNUAL-ST RELIABILITY & PWC1A-1C-MAINTENANCE-ANNUAL-RELIABILITY	1,223
West County 2	03/08/2021	-	03/17/2021	PWC2-MAINTENANCE-ANNUAL-ST, BOP RELIABILITY (BLOCK) & PWC2A-2C-MAINTENANCE-ANNUAL-RELIABILITY	1,248
West County 3	02/15/2021	-	04/05/2021	PWC3C-CT-MAJOR-HRSG-BALANCE OF PLANT	418
West County 3	10/26/2021	-	12/14/2021	PWC3A-CT-MAJOR-BALANCE OF PLANT. SCR CATALYST	418

*Approximate load reduction MW are based on the unit's estimated MW rating at the start of the outage period

FLORIDA POWER & LIGHT COMPANY
2018 SoBRA PROJECT
FIRST YEAR ANNUALIZED REVENUE REQUIREMENT [1]
($000)

Line No	(1) Description	(2) Page Reference	(3) Initial SoBRA [2] Amount	(4) Final SoBRA [3] Amount	(5) True-up Amount
1	Jurisdictional Adjusted Rate Base	Page 2	$ 364,122	$ 333,862	$ (30,260)
2	Rate of Return on Rate Base		8.30%	8.30%	8.30%
3	Required Jurisdictional Net Operating Income	Line 1 x Line 2	$ 30,218	$ 27,707	$ (2,511)
4	Required Net Operating Income		(6,519)	(6,519)	0
5	Net Operating Income Deficiency (Excess)	Line 3 - Line 4	$ 36,737	$ 34,226	$ (2,511)
6	Net Operating Income Multiplier[4]		1.63025	1.63025	1.63025
7	Revenue Requirement	Line 5 x Line 6	$ 59,890	$ 55,797	$ (4,094)
8					

9 NOTES:

10 [1] Represents the revenue requirement for projected 12-month period for the 2018 SoBRA Project.

11 [2] Initial SoBRA calculation approved by the Commission in Order No. PSC-2018-0028-FOF-EI, Docket No. 20180001-EI (issued on January 8, 2018).

12 [3] Based on inputs included in the initial SoBRA in column 3, except projected capital costs were replaced with final actual capital costs. See Page 2 for details on the final actual capital costs.

13 [4] Represents the net operating income multiplier from page 9 of Exhibit KO-20, Docket No. 160021-EI.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20200001-EI EXHIBIT: 21
PARTY: FLORIDA POWER & LIGHT COMPANY – DIRECT
DESCRIPTION: L. Fuentes LF-1

FLORIDA POWER & LIGHT COMPANY
2018 SoBRA PROJECT
JURISDICTIONAL ADJUSTED RATE BASE
13-MONTH AVERAGE
($000)

		Initial SoBRA[1]			Final SoBRA[2]		
Line No.	(1) Description	(2) Total Company	(3) FPSC Jurisdictional	(4) Jurisdictional Factor[3]	(5) Total Company	(6) FPSC Jurisdictional	(7) Jurisdictional Factor[3]
1							
2	PLANT IN SERVICE:						
3							
4	ELECTRIC PLANT IN SERVICE - OTHER PRODUCTION	$ 412,149	$ 394,283	0.956652	$ 364,982	$ 349,161	0.956652
5							
6	ELECTRIC PLANT IN SERVICE - TRANSMISSION	$ 9,535	$ 8,467	0.887974	$ 20,942	$ 18,596	0.887974
7	ELECTRIC PLANT IN SERVICE - TRANSMISSION - GSU's	3,383	3,212	0.949382	7,616	7,230	0.949382
8	TOTAL ELECTRIC PLANT IN SERVICE - TRANSMISSION	$ 12,918	$ 11,678	0.904056	$ 28,558	$ 25,826	0.904056
9							
10	NON-DEPRECIABLE PROPERTY (LAND)	$ 17,518	$ 16,758	0.956652	$ 18,265	$ 17,473	0.956652
11							
12	TOTAL PLANT IN SERVICE	$ 442,585	$ 422,720	0.955117	$ 411,805	$ 392,460	0.955117
13							
14							
15	ACCUMULATED PROVISION FOR DEPRECIATION:						
16							
17	ACCUM PROVISION FOR DEPRECIATION - OTHER PRODUCTION	$ 6,945	$ 6,644	0.956652	$ 6,945	$ 6,644	0.956652
18							
19	ACCUM PROVISION DEPRECIATION - TRANSMISSION	$ 95	$ 85	0.887974	$ 95	$ 85	0.887974
20	ACCUM PROVISION DEPRECIATION - TRANSMISSION - GSU	45	42	0.949382	45	42	0.949382
21	TOTAL ACCUM PROVISION FOR DEPRECIATION - TRANSMISSION	$ 140	$ 127	0.907561	$ 140	$ 127	0.907561
22							
23	TOTAL ACCUMULATED PROVISION FOR DEPRECIATION	$ 7,085	$ 6,771	0.955682	$ 7,085	$ 6,771	0.955682
24							
25							
26	ACCUMULATED DEFERRED INCOME TAXES[2]	$ (54,263)	$ (51,827)	0.955107	$ (54,263)	$ (51,827)	0.955107
27							
28	TOTAL RATE BASE	$ 381,237	$ 364,122	0.955107	$ 350,457	$ 333,862	0.955107
29							
30							

31 NOTES:

32 [1] Reflects projected rate base included in the Initial SoBRA calculation approved by the Commission in Order No. PSC-2018-0028-FOF-EI, Docket No. 20180001-EI (issued on January 8, 2018).

33 [2] Reflects rate base included in the initial SoBRA in column 3, except projected plant in service has been replaced with final actual plant in service.

34 [3] Based on FPL's cost of service calculations prepared for the 2017 budget cycle.

FLORIDA POWER & LIGHT COMPANY
SOBRA FACTOR CALCULATION
REVISED 2018 SOBRA FACTOR

	2018 SOBRA FACTOR TRUE-UP CALCULATION	**($Million)**	**Source**
(A)	Initial 2018 Project Jurisdictional Annualized Revenue Requirement *	$59.890	See Note
(B)	Revised 2018 Project Jurisdictional Annualized Revenue Requirement	$55.797	Attachment LF-1 as Filed
(C)	Change in Jurisdictional Annualized Revenue Requirement	($4.094)	Attachment LF-1 as Filed
(D)	Total Retail Base Revenues From the Sales of Electricity *	$6,518.299	See Note
(E)	Revised SoBRA Factor [(B) / (D)]	0.856%	
(F)	Inital SoBRA Factor *	0.919%	See Note

* As filed in TCC-1, Page 1 of 1; Docket No. 20170001-EI

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20200001-EI EXHIBIT: 22
PARTY: FLORIDA POWER & LIGHT COMPANY – DIRECT
DESCRIPTION: E.J. Anderson EJA-1

FLORIDA POWER & LIGHT COMPANY
2018 PROJECT REVENUE - SOBRA PROVISION FOR REFUND CALCULATION

	(1)	(2)	(3)	(4)	(5)
	ACTUALS			REVISED	
	UNBILLED SOBRA REV	BILLED SOBRA REV	UNBILLED + BILLED SOBRA REV	UNBILLED + BILLED SOBRA REV	REFUND
Mar-18	136,392	4,229,427	4,365,819	4,067,390	298,429
Apr-18	283,351	4,428,279	4,711,631	4,389,563	322,067
May-18	42,341	4,837,695	4,880,036	4,546,457	333,579
Jun-18	243,149	5,244,614	5,487,763	5,112,643	375,121
Jul-18	142,853	5,798,937	5,941,790	5,535,634	406,156
Aug-18	(3,233)	5,981,099	5,977,866	5,569,244	408,622
Sep-18	90,191	5,659,063	5,749,254	5,356,259	392,995
Oct-18	(214,656)	5,721,314	5,506,658	5,130,245	376,412
Nov-18	(370,856)	4,997,824	4,626,968	4,310,688	316,280
Dec-18	(59,731)	4,417,398	4,357,666	4,059,794	297,872
Jan-19	(196,059)	4,407,254	4,211,194	3,923,335	287,860
Feb-19	125,205	4,132,196	4,257,402	3,966,383	291,018
Mar-19	68,458	4,421,157	4,489,615	4,182,723	306,891
Apr-19	290,282	4,773,305	5,063,587	4,717,462	346,126
May-19	543,001	5,220,793	5,763,794	5,369,805	393,989
Jun-19	21,531	5,930,802	5,952,334	5,545,457	406,877
Jul-19	78,292	6,192,825	6,271,117	5,842,449	428,667
Aug-19	9,903	6,090,159	6,100,062	5,683,087	416,975
Sep-19	(307,562)	6,241,366	5,933,804	5,528,194	405,610
Oct-19	34,766	5,835,955	5,870,720	5,469,422	401,298
Nov-19	(679,542)	5,253,349	4,573,807	4,261,161	312,646
Dec-19	112,274	4,456,227	4,568,501	4,256,218	312,284
Jan-20	(181,473)	4,612,935	4,431,462	4,128,546	302,916
Feb-20	57,654	4,326,010	4,383,664	4,084,015	299,649
Mar-20	492,236	4,526,504	5,018,740	4,675,680	343,060
Apr-20	(56,478)	5,276,713	5,220,234	4,863,401	356,833
May-20	215,763	5,327,076	5,542,839	5,163,953	378,885
Jun-20	286,752	5,861,934	6,148,686	5,728,387	420,299
Jul-20	(27,955)	6,458,332	6,430,378	5,990,824	439,554
Aug-20	(174,381)	6,280,121	6,105,739	5,688,376	417,363
Sep-20	(254,577)	6,078,086	5,823,509	5,425,438	398,071
Oct-20	(93,696)	5,564,740	5,471,044	5,097,066	373,978
Nov-20	(393,014)	4,964,437	4,571,423	4,258,939	312,483
Dec-20	142,199	4,499,846	4,642,045	4,324,734	317,311
TOTAL		178,047,775	178,451,153	166,252,975	12,198,178

FLORIDA POWER & LIGHT COMPANY
SOBRA PROVISION FOR REFUND INTEREST

	REFUND ACCRUAL	CUMULATIVE REFUND	INTEREST RATE	CUM. REFUND WITH INTEREST	MONTHLY INTEREST	CUMULATIVE INTEREST
Mar-18	298,429	298,429	0.0014500	298,646	216	216
Apr-18	322,067	620,497	0.0015458	621,424	711	927
May-18	333,579	954,076	0.0015458	956,221	1,218	2,145
Jun-18	375,121	1,329,196	0.0016000	1,333,172	1,830	3,975
Jul-18	406,156	1,735,352	0.0016500	1,741,863	2,535	6,510
Aug-18	408,622	2,143,974	0.0016500	2,153,696	3,211	9,721
Sep-18	392,995	2,536,969	0.0017458	2,550,794	4,103	13,824
Oct-18	376,412	2,913,382	0.0018667	2,932,319	5,113	18,937
Nov-18	316,280	3,229,662	0.0019042	3,254,484	5,885	24,822
Dec-18	297,872	3,527,534	0.0019667	3,559,049	6,693	31,515
Jan-19	287,860	3,815,394	0.0020167	3,854,377	7,468	38,983
Feb-19	291,018	4,106,412	0.0020125	4,153,445	8,050	47,033
Mar-19	306,891	4,413,303	0.0020375	4,469,111	8,775	55,808
Apr-19	346,126	4,759,429	0.0020458	4,824,734	9,497	65,305
May-19	393,989	5,153,418	0.0020083	5,228,808	10,085	75,391
Jun-19	406,877	5,560,295	0.0019625	5,646,346	10,661	86,051
Jul-19	428,667	5,988,962	0.0018417	6,085,807	10,793	96,845
Aug-19	416,975	6,405,937	0.0017292	6,513,666	10,884	107,729
Sep-19	405,610	6,811,547	0.0016750	6,930,526	11,250	118,979
Oct-19	401,298	7,212,845	0.0015125	7,342,610	10,786	129,765
Nov-19	312,646	7,525,492	0.0013875	7,665,661	10,405	140,169
Dec-19	312,284	7,837,775	0.0013583	7,988,569	10,625	150,794
Jan-20	302,916	8,140,692	0.0013458	8,302,441	10,955	161,749
Feb-20	299,649	8,440,341	0.0013333	8,613,359	11,270	173,019
Mar-20	343,060	8,783,401	0.0015708	8,970,219	13,800	186,818
Apr-20	356,833	9,140,234	0.0009458	9,335,706	8,653	195,472
May-20	378,885	9,519,120	0.0000583	9,715,147	556	196,027
Jun-20	420,299	9,939,418	0.0000875	10,136,314	868	196,896
Jul-20	439,554	10,378,972	0.0001000	10,576,903	1,036	197,931
Aug-20	417,363	10,796,335	0.0001000	10,995,345	1,079	199,010
Sep-20	398,071	11,194,406	0.0001000	11,394,535	1,119	200,129
Oct-20	373,978	11,568,384	0.0001000	11,769,671	1,158	201,287
Nov-20	312,483	11,880,867	0.0001000	12,083,347	1,193	202,480
Dec-20	317,311	12,198,178	0.0001000	12,401,882	1,224	203,704
TOTAL	12,198,178				203,704	
				Total Cumulative Refund with Interest	12,401,882	

FLORIDA POWER & LIGHT COMPANY
2018 SOBRA PROSPECTIVE ADJUSTMENT
FOR JANUARY 1, 2021

2018 SOBRA PROSPECTIVE ADJUSTMENT	($Million)	Source
(A) Jurisdictional Annualized Revenue Requirement	($4.094)	Attachment LF-1 as Filed
(B) Total Retail Base Revenues From the Sales of Electricity	6,995.756	Attachment EJA-3 Page 1 of 1
(C) SoBRA ADJUSTMENT FACTOR [(A) / (B)]	-0.059%	

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20200001-EI EXHIBIT: 23
PARTY: FLORIDA POWER & LIGHT COMPANY – DIRECT
DESCRIPTION: E.J. Anderson EJA-2

FLORIDA POWER & LIGHT COMPANY
RETAIL BASE REVENUES
12 MONTHS BEGINNING JANUARY 2021

Customer Class	2021 Jan	Feb	Mar	Apr	May	Jun	Jul
Residential	324,681,267	288,143,723	289,004,616	314,498,385	352,906,636	407,384,296	443,859,832
Commercial	185,871,531	177,643,702	179,272,747	191,077,516	199,050,653	206,214,831	210,476,646
Industrial	8,227,563	8,239,018	8,322,506	8,325,645	8,419,763	8,616,902	8,469,414
Street & Highway	7,768,057	7,774,537	7,783,655	7,791,282	7,800,529	7,809,352	7,825,083
Other	105,041	116,340	118,918	114,371	117,343	128,568	139,942
Railroads & Railways	316,725	302,894	299,232	316,915	315,014	330,706	338,001
Total Jurisdictional Billed Revenue	526,970,184	482,220,215	484,801,674	522,124,114	568,609,938	630,484,655	671,108,918
CILC/CDR Incentive	4,747,655	4,343,988	4,440,894	6,004,619	5,792,824	8,813,684	6,535,966
Unbilled Revenue	63,384	58,001	58,312	62,801	68,392	75,835	80,721
Total Retail Base Revenues From the Sales of Electricity	$ 531,781,223	$ 486,622,204	$ 489,300,880	$ 528,191,534	$ 574,471,155	$ 639,374,173	$ 677,725,605

Customer Class	2021 Aug	Sept	Oct	Nov	Dec	12 Months Ending
Residential	459,028,068	448,506,127	394,197,851	324,927,554	303,037,430	4,350,175,786
Commercial	214,656,098	219,060,105	207,731,525	196,842,618	190,290,813	2,378,188,786
Industrial	8,267,460	8,416,207	8,155,374	8,330,601	8,302,993	100,093,446
Street & Highway	7,833,585	7,841,777	7,845,031	7,853,427	7,862,069	93,788,384
Other	135,864	134,758	107,500	104,332	103,351	1,426,327
Railroads & Railways	325,549	341,002	330,378	321,389	305,460	3,843,263
Total Jurisdictional Billed Revenue	690,246,624	684,299,975	618,367,658	538,379,922	509,902,115	6,927,515,993
CILC/CDR Incentive Credit	6,062,439	6,295,229	6,337,589	5,154,802	6,970,641	71,500,329
Unbilled Revenue	83,023	82,308	74,377	64,756	61,331	833,241
Total Retail Base Revenues From the Sales of Electricity	$ 696,392,086	$ 690,677,512	$ 624,779,624	$ 543,599,480	$ 516,934,087	$ 6,999,849,563
Adjustment for 2018 Project True-Up						$ (4,093,912)
Adjusted Retail Base Revenues From the Sales of Electricity						$ 6,995,755,651

Totals may not add due to rounding

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20200001-EI EXHIBIT: 24
PARTY: FLORIDA POWER & LIGHT COMPANY – DIRECT
DESCRIPTION: E.J. Anderson EJA-3

FLORIDA POWER & LIGHT COMPANY
SUMMARY OF TARIFF CHANGES
JANUARY 1, 2021 RATES ADJUSTED FOR 2018 SOBRA TRUE-UP

LINE NO.	(1) RATE SCHEDULE	(2) TYPE OF CHARGE	(3) MAY 1, 2020 PROPOSED RATE*	(4) JANUARY 1, 2021 PROPOSED RATE	(5) TOTAL CHANGE IN RATE	(6) % CHANGE IN RATE
1	RS-1	Residential Service				
2		Customer Charge/Minimum	$8.34	$8.34	$0.00	0.0%
3						
4		Base Energy Charge (¢ per kWh)				
5		First 1,000 kWh	6.160	6.156	(0.004)	-0.1%
6		All additional kWh	7.222	7.218	(0.004)	-0.1%
7						
8						
9	RTR-1	Residential Service -Time of Use				
10		Customer Charge/Minimum	$8.34	$8.34	$0.00	0.0%
11						
12		Base Energy Charge (¢ per kWh)				
13		On-Peak	10.989	10.983	(0.006)	-0.1%
14		Off-Peak	(4.889)	(4.886)	0.003	-0.1%
15						
16						
17	GS-1	General Service - Non Demand (0-20 kW)				
18		Customer Charge/Minimum				
19		Metered	$10.62	$10.61	($0.01)	-0.1%
20		Unmetered Service Credit	($5.30)	($5.30)	$0.00	0.0%
21						
22		Base Energy Charge (¢ per kWh)	6.013	6.009	(0.004)	-0.1%
23						
24						
25	GST-1	General Service - Non Demand - Time of Use (0-20 kW)				
26		Customer Charge/Minimum	$10.62	$10.61	($0.01)	-0.1%
27						
28		Base Energy Charge (¢ per kWh)				
29		On-Peak	11.103	11.096	(0.007)	-0.1%
30		Off-Peak	3.802	3.800	(0.002)	-0.1%
31						
32						
33	GSD-1	General Service Demand (21-499 kW)				
34		Customer Charge	$26.50	$26.48	($0.02)	-0.1%
35						
36		Demand Charge ($/kW)	$9.98	$9.97	($0.01)	-0.1%
37						
38		Base Energy Charge (¢ per kWh)	2.222	2.221	(0.001)	0.0%
39						
40						
41						
42						

LINE NO.	(1) RATE SCHEDULE	(2) TYPE OF CHARGE	(3) MAY 1, 2020 PROPOSED RATE*	(4) JANUARY 1, 2021 PROPOSED RATE	(5) TOTAL CHANGE IN RATE	(6) % CHANGE IN RATE
1	GSD-1EV**	General Service Demand (21-499 kW)				
2		Customer Charge	$26.50	$26.48	($0.02)	-0.1%
3						
4		Demand Charge ($/kW)	$9.98	$9.97	($0.01)	-0.1%
5						
6		Base Energy Charge (¢ per kWh)	2.222	2.221	(0.001)	0.0%
7						
8						
9	GSDT-1	General Service Demand - Time of Use (21-499 kW)				
10		Customer Charge	$26.50	$26.48	($0.02)	-0.1%
11						
12		Demand Charge - On-Peak ($/kW)	$9.98	$9.97	($0.01)	-0.1%
13						
14		Base Energy Charge (¢ per kWh)				
15		On-Peak	4.533	4.530	(0.003)	-0.1%
16		Off-Peak	1.199	1.198	(0.001)	-0.1%
17						
18						
11	GSLD-1	General Service Large Demand (500-1999 kW)				
12		Customer Charge	$79.45	$79.40	($0.05)	-0.1%
13						
14		Demand Charge ($/kW)	$12.19	$12.18	($0.01)	-0.1%
15						
16		Base Energy Charge (¢ per kWh)	1.755	1.754	(0.001)	-0.1%
17						
18						
19	GSLD-1 EV**	General Service Large Demand (500-1999 kW)				
20		Customer Charge	$79.45	$79.40	($0.05)	-0.1%
21						
22		Demand Charge ($/kW)	$12.19	$12.18	($0.01)	-0.1%
23						
24		Base Energy Charge (¢ per kWh)	1.755	1.754	(0.001)	-0.1%
25						
26						
27	GSLDT-1	General Service Large Demand - Time of Use (500-1999 kW)				
28		Customer Charge	$79.45	$79.40	($0.05)	-0.1%
29						
30		Demand Charge - On-Peak ($/kW)	$12.19	$12.18	($0.01)	-0.1%
31						
32		Base Energy Charge (¢ per kWh)				
33		On-Peak	2.873	2.871	(0.002)	-0.1%
34		Off-Peak	1.266	1.265	(0.001)	-0.1%
35						
36						
37	**Proposed to become effective if approved in Docket No. 20200170 (rates align with GSD-1 and GSLD-1)					
38						
39						
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LINE NO.	(1) RATE SCHEDULE	(2) TYPE OF CHARGE	(3) MAY 1, 2020 PROPOSED RATE*	(4) JANUARY 1, 2021 PROPOSED RATE	(5) TOTAL CHANGE IN RATE	(6) % CHANGE IN RATE
1	CS-1	Curtailable Service (500-1999 kW)				
2		Customer Charge	$105.94	$105.88	($0.06)	-0.1%
3						
4		Demand Charge ($/kW)	$12.19	$12.18	($0.01)	-0.1%
5						
6		Base Energy Charge (¢ per kWh)	1.755	1.754	(0.001)	-0.1%
7						
8		Monthly Credit ($ per kW)	($2.05)	($2.05)	$0.00	0.0%
9						
10		Charges for Non-Compliance of Curtailment Demand				
11		Rebilling for last 36 months (per kW)	$2.05	$2.05	$0.00	0.0%
12		Penalty Charge-current month (per kW)	$4.41	$4.41	$0.00	0.0%
13		Early Termination Penalty charge (per kW)	$1.30	$1.30	$0.00	0.0%
14						
15	CST-1	Curtailable Service -Time of Use (500-1999 kW)				
16		Customer Charge	$105.94	$105.88	($0.06)	-0.1%
17						
18		Demand Charge - On-Peak ($/kW)	$12.19	$12.18	($0.01)	-0.1%
19						
20		Base Energy Charge (¢ per kWh)				
21		On-Peak	2.873	2.871	(0.002)	-0.1%
22		Off-Peak	1.266	1.265	(0.001)	-0.1%
23						
24		Monthly Credit ($ per kW)	($2.05)	($2.05)	$0.00	0.0%
25						
26		Charges for Non-Compliance of Curtailment Demand				
27		Rebilling for last 36 months (per kW)	$2.05	$2.05	$0.00	0.0%
28		Penalty Charge-current month (per kW)	$4.41	$4.41	$0.00	0.0%
29		Early Termination Penalty charge (per kW)	$1.30	$1.30	$0.00	0.0%
30						
31	GSLD-2	General Service Large Demand (2000 kW +)				
32		Customer Charge	$238.17	$238.03	($0.14)	-0.1%
33						
34		Demand Charge ($/kW)	$12.69	$12.68	($0.01)	-0.1%
35						
36		Base Energy Charge (¢ per kWh)	1.579	1.578	(0.001)	-0.1%
37						
38						
39						
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41						
42						

LINE NO.	(1) RATE SCHEDULE	(2) TYPE OF CHARGE	(3) MAY 1, 2020 PROPOSED RATE*	(4) JANUARY 1, 2021 PROPOSED RATE	(5) TOTAL CHANGE IN RATE	(6) % CHANGE IN RATE
1	GSLDT-2	General Service Large Demand - Time of Use (2000 kW +)				
2		Customer Charge	$238.17	$238.03	($0.14)	-0.1%
3						
4		Demand Charge - On-Peak ($/kW)	$12.69	$12.68	($0.01)	-0.1%
5						
6		Base Energy Charge (¢ per kWh)				
7		On-Peak	2.452	2.451	(0.001)	0.0%
8		Off-Peak	1.237	1.236	(0.001)	-0.1%
9						
10						
11	CS-2	Curtailable Service (2000 kW +)				
12		Customer Charge	$264.63	$264.47	($0.16)	-0.1%
13						
14		Demand Charge ($/kW)	$12.69	$12.68	($0.01)	-0.1%
15						
16		Base Energy Charge (¢ per kWh)	1.579	1.578	(0.001)	-0.1%
17						
18		Monthly Credit (per kW)	($2.05)	($2.05)	$0.00	0.0%
19						
20		Charges for Non-Compliance of Curtailment Demand				
21		Rebilling for last 36 months (per kW)	$2.05	$2.05	$0.00	0.0%
22		Penalty Charge-current month (per kW)	$4.40	$4.40	$0.00	0.0%
23		Early Termination Penalty charge (per kW)	$1.30	$1.30	$0.00	0.0%
24						
25	CST-2	Curtailable Service -Time of Use (2000 kW +)				
26		Customer Charge	$264.63	$264.47	($0.16)	-0.1%
27						
28		Demand Charge - On-Peak ($/kW)	$12.69	$12.68	($0.01)	-0.1%
29						
30		Base Energy Charge (¢ per kWh)				
31		On-Peak	2.452	2.451	(0.001)	0.0%
32		Off-Peak	1.237	1.236	(0.001)	-0.1%
33						
34		Monthly Credit (per kW)	($2.05)	($2.05)	$0.00	0.0%
35						
36		Charges for Non-Compliance of Curtailment Demand				
37		Rebilling for last 36 months (per kW)	$2.05	$2.05	$0.00	0.0%
38		Penalty Charge-current month (per kW)	$4.40	$4.40	$0.00	0.0%
39		Early Termination Penalty charge (per kW)	$1.30	$1.30	$0.00	0.0%
40						
41						
42						

LINE NO.	(1) RATE SCHEDULE	(2) TYPE OF CHARGE	(3) MAY 1, 2020 PROPOSED RATE*	(4) JANUARY 1, 2021 PROPOSED RATE	(5) TOTAL CHANGE IN RATE	(6) % CHANGE IN RATE
1	GSLD-3	General Service Large Demand (2000 kW +)				
2		Customer Charge	$2,114.77	$2,113.52	($1.25)	-0.1%
3						
4		Demand Charge ($/kW)	$9.84	$9.83	($0.01)	-0.1%
5						
6		Base Energy Charge (¢ per kWh)	1.135	1.134	(0.001)	-0.1%
7						
8						
9	GSLDT-3	General Service Large Demand - Time of Use (2000 kW +)				
10		Customer Charge	$2,114.77	$2,113.52	($1.25)	-0.1%
11						
12		Demand Charge - On-Peak ($/kW)	$9.84	$9.83	($0.01)	-0.1%
13						
14		Base Energy Charge (¢ per kWh)				
15		On-Peak	1.296	1.295	(0.001)	-0.1%
16		Off-Peak	1.078	1.077	(0.001)	-0.1%
17						
18						
19	CS-3	Curtailable Service (2000 kW +)				
20		Customer Charge	$2,141.21	$2,139.95	($1.26)	-0.1%
21						
22		Demand Charge ($/kW)	$9.84	$9.83	($0.01)	-0.1%
23						
24		Base Energy Charge (¢ per kWh)	1.135	1.134	(0.001)	-0.1%
25						
26		Monthly Credit (per kW)	($2.05)	($2.05)	$0.00	0.0%
27						
28		Charges for Non-Compliance of Curtailment Demand				
29		Rebilling for last 36 months (per kW)	$2.05	$2.05	$0.00	0.0%
30		Penalty Charge-current month (per kW)	$4.40	$4.40	$0.00	0.0%
31		Early Termination Penalty charge (per kW)	$1.30	$1.30	$0.00	0.0%
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LINE NO.	(1) RATE SCHEDULE	(2) TYPE OF CHARGE	(3) MAY 1, 2020 PROPOSED RATE*	(4) JANUARY 1, 2021 PROPOSED RATE	(5) TOTAL CHANGE IN RATE	(6) % CHANGE IN RATE
1	CST-3	Curtailable Service -Time of Use (2000 kW +)				
2		Customer Charge	$2,141.21	$2,139.95	($1.26)	-0.1%
3						
4		Demand Charge - On-Peak ($/kW)	$9.84	$9.83	($0.01)	-0.1%
5						
6		Base Energy Charge (¢ per kWh)				
7		On-Peak	1.296	1.295	(0.001)	-0.1%
8		Off-Peak	1.078	1.077	(0.001)	-0.1%
9						
10		Monthly Credit (per kW)	($2.05)	($2.05)	$0.00	0.0%
11						
12		Charges for Non-Compliance of Curtailment Demand				
13		Rebilling for last 36 months (per kW)	$2.05	$2.05	$0.00	0.0%
14		Penalty Charge-current month (per kW)	$4.40	$4.40	$0.00	0.0%
15		Early Termination Penalty charge (per kW)	$1.30	$1.30	$0.00	0.0%
16						
17	OS-2	Sports Field Service [Schedule closed to new customers]				
18		Customer Charge	$132.86	$132.78	($0.08)	-0.1%
19						
20		Base Energy Charge (¢ per kWh)	8.360	8.355	(0.005)	-0.1%
21						
22						
23	MET	Metropolitan Transit Service				
24		Customer Charge	$636.08	$635.70	($0.38)	-0.1%
25						
26		Base Demand Charge ($/kW)	$13.46	$13.45	($0.01)	-0.1%
27						
28		Base Energy Charge (¢ per kWh)	1.796	1.795	(0.001)	-0.1%
29						
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LINE NO.	(1) RATE SCHEDULE	(2) TYPE OF CHARGE	(3) MAY 1, 2020 PROPOSED RATE*	(4) JANUARY 1, 2021 PROPOSED RATE	(5) TOTAL CHANGE IN RATE	(6) % CHANGE IN RATE
1	CILC-1	Commercial/Industrial Load Control Program [Schedule closed to new customers]				
2		Customer Charge				
3		(G) 200-499kW	$158.71	$158.62	($0.09)	-0.1%
4		(D) above 500kW	$264.16	$264.00	($0.16)	-0.1%
5		(T) transmission	$2,342.78	$2,341.40	($1.38)	-0.1%
6						
7		Base Demand Charge ($/kW)				
8		per kW of Max Demand All kW:				
9		(G) 200-499kW	$4.23	$4.23	$0.00	0.0%
10		(D) above 500kW	$4.44	$4.44	$0.00	0.0%
11		(T) transmission	None	None	None	N/A
12						
13						
14		per kW of Load Control On-Peak:				
15		(G) 200-499kW	$2.78	$2.78	$0.00	0.0%
16		per kW of Load Control On-Peak:				
17		(D) above 500kW	$3.17	$3.17	$0.00	0.0%
18		(T) transmission	$3.37	$3.37	$0.00	0.0%
19						
20						
21						
22		Per kW of Firm On-Peak Demand				
23		(G) 200-499kW	$10.58	$10.57	($0.01)	-0.1%
24		(D) above 500kW	$11.51	$11.50	($0.01)	-0.1%
25		(T) transmission	$12.31	$12.30	($0.01)	-0.1%
26						
27		Base Energy Charge (¢ per kWh)				
28		On-Peak				
29		(G) 200-499kW	1.576	1.575	(0.001)	-0.1%
30		(D) above 500kW	1.061	1.060	(0.001)	-0.1%
31		(T) transmission	0.984	0.983	(0.001)	-0.1%
32		Off-Peak				
33		(G) 200-499kW	1.576	1.575	(0.001)	-0.1%
34		(D) above 500kW	1.061	1.060	(0.001)	-0.1%
35		(T) transmission	0.984	0.983	(0.001)	-0.1%
36						
37		Excess "Firm Demand" or Termination Charge	Difference between Firm and			
38		¤ Up to prior 60 months of service	Load-Control On-Peak Demand Charge			
39						
40						
41		¤ Penalty Charge per kW for each month of rebilling	$1.14	$1.14	$0.00	0.0%
42						

LINE NO.	(1) RATE SCHEDULE		(2) TYPE OF CHARGE	(3) MAY 1, 2020 PROPOSED RATE*	(4) JANUARY 1, 2021 PROPOSED RATE	(5) TOTAL CHANGE IN RATE	(6) % CHANGE IN RATE
1	CDR		Commercial/Industrial Demand Reduction Rider				
2			Monthly Rate				
3			Customer Charge	Otherwise Applicable Rate			
4			Demand Charge	Otherwise Applicable Rate			
5			Energy Charge	Otherwise Applicable Rate			
6							
7			Monthly Administrative Adder				
8			GSD-1	$132.52	$132.44	($0.08)	-0.1%
9			GSDT-1	$132.52	$132.44	($0.08)	-0.1%
10			GSLD-1, GSLDT-1	$185.39	$185.28	($0.11)	-0.1%
11			GSLD-2, GSLDT-2	$79.39	$79.34	($0.05)	-0.1%
12			GSLD-3, GSLDT-3	$237.91	$237.77	($0.14)	-0.1%
13			HLFT	Applicable General Service Level Rate			
14			SDTR	Applicable General Service Level Rate			
15							
16			Utility Controlled Demand Credit $/kW	($8.71)	($8.70)	$0.01	-0.1%
17							
18			Excess "Firm Demand"	$8.71	$8.70	($0.01)	-0.1%
19			¤ Up to prior 60 months of service				
20							
21			¤ Penalty Charge per kW for	$1.14	$1.14	$0.00	0.0%
22			each month of rebilling				
23							
24	SL-1		Street Lighting				
25			Charges for FPL-Owned Units				
26			Fixture				
27			Sodium Vapor 6,300 lu 70 watts	$4.14	$4.14	$0.00	0.0%
28			Sodium Vapor 9,500 lu 100 watts	$4.21	$4.21	$0.00	0.0%
29			Sodium Vapor 16,000 lu 150 watts	$4.34	$4.34	$0.00	0.0%
30			Sodium Vapor 22,000 lu 200 watts	$6.58	$6.58	$0.00	0.0%
31			Sodium Vapor 50,000 lu 400 watts	$6.64	$6.64	$0.00	0.0%
32		**	Sodium Vapor 27,500 lu 250 watts	$6.99	$6.99	$0.00	0.0%
33		**	Sodium Vapor 140,000 lu 1,000 watts	$10.54	$10.53	($0.01)	-0.1%
34		**	Mercury Vapor 6,000 lu 140 watts	$3.27	$3.27	$0.00	0.0%
35		**	Mercury Vapor 8,600 lu 175 watts	$3.33	$3.33	$0.00	0.0%
36		**	Mercury Vapor 11,500 lu 250 watts	$5.54	$5.54	$0.00	0.0%
37		**	Mercury Vapor 21,500 lu 400 watts	$5.51	$5.51	$0.00	0.0%
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LINE NO.	(1) RATE SCHEDULE		(2) TYPE OF CHARGE		(3) MAY 1, 2020 PROPOSED RATE*	(4) JANUARY 1, 2021 PROPOSED RATE	(5) TOTAL CHANGE IN RATE	(6) % CHANGE IN RATE
1	SL-1		Street Lighting (continued))					
2			Maintenance					
3			Sodium Vapor 6,300 lu 70 watts		$1.98	$1.98	$0.00	0.0%
4			Sodium Vapor 9,500 lu 100 watts		$1.99	$1.99	$0.00	0.0%
5			Sodium Vapor 16,000 lu 150 watts		$2.02	$2.02	$0.00	0.0%
6			Sodium Vapor 22,000 lu 200 watts		$2.57	$2.57	$0.00	0.0%
7			Sodium Vapor 50,000 lu 400 watts		$2.58	$2.58	$0.00	0.0%
8		**	Sodium Vapor 27,500 lu 250 watts		$2.79	$2.79	$0.00	0.0%
9		**	Sodium Vapor 140,000 lu 1,000 watts		$5.01	$5.01	$0.00	0.0%
10		**	Mercury Vapor 6,000 lu 140 watts		$1.77	$1.77	$0.00	0.0%
11		**	Mercury Vapor 8,600 lu 175 watts		$1.77	$1.77	$0.00	0.0%
12		**	Mercury Vapor 11,500 lu 250 watts		$2.55	$2.55	$0.00	0.0%
13		**	Mercury Vapor 21,500 lu 400 watts		$2.51	$2.51	$0.00	0.0%
14								
15			Energy Non-Fuel	kWh				
16			Sodium Vapor 6,300 lu 70 watts	29	$0.89	$0.89	$0.00	0.0%
17			Sodium Vapor 9,500 lu 100 watts	41	$1.26	$1.26	$0.00	0.0%
18			Sodium Vapor 16,000 lu 150 watts	60	$1.84	$1.84	$0.00	0.0%
19			Sodium Vapor 22,000 lu 200 watts	88	$2.70	$2.69	($0.01)	-0.4%
20			Sodium Vapor 50,000 lu 400 watts	168	$5.15	$5.14	($0.01)	-0.2%
21		**	Sodium Vapor 27,500 lu 250 watts	116	$3.55	$3.55	$0.00	0.0%
22		**	Sodium Vapor 140,000 lu 1,000 watts	411	$12.59	$12.58	($0.01)	-0.1%
23		**	Mercury Vapor 6,000 lu 140 watts	62	$1.90	$1.90	$0.00	0.0%
24		**	Mercury Vapor 8,600 lu 175 watts	77	$2.36	$2.36	$0.00	0.0%
25		**	Mercury Vapor 11,500 lu 250 watts	104	$3.19	$3.18	($0.01)	-0.3%
26		**	Mercury Vapor 21,500 lu 400 watts	160	$4.90	$4.90	$0.00	0.0%
27								
28								
29		Note: The proposed monthly Non-Fuel Energy charge is calculated by multiplying the kWh rating for each fixture by the proposed						
30		Non-Fuel Energy Rate. This avoids rounding issues caused by separating the increases into the various components.						
31		**Note: These units are closed to new Company installations.						
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LINE NO.	(1) RATE SCHEDULE		(2) TYPE OF CHARGE		(3) MAY 1, 2020 PROPOSED RATE*	(4) JANUARY 1, 2021 PROPOSED RATE	(5) TOTAL CHANGE IN RATE	(6) % CHANGE IN RATE
1	SL-1		Street Lighting (continued))					
2			Charge for Customer-Owned Units					
3			Relamping and Energy					
4			Sodium Vapor 6,300 lu 70 watts		$2.88	$2.88	$0.00	0.0%
5			Sodium Vapor 9,500 lu 100 watts		$3.26	$3.26	$0.00	0.0%
6			Sodium Vapor 16,000 lu 150 watts		$3.87	$3.87	$0.00	0.0%
7			Sodium Vapor 22,000 lu 200 watts		$5.24	$5.23	($0.01)	-0.2%
8			Sodium Vapor 50,000 lu 400 watts		$7.70	$7.69	($0.01)	-0.1%
10		**	Sodium Vapor 27,500 lu 250 watts		$6.31	$6.31	$0.00	0.0%
11		**	Sodium Vapor 140,000 lu 1,000 watts		$17.64	$17.63	($0.01)	-0.1%
12		**	Mercury Vapor 6,000 lu 140 watts		$3.68	$3.68	$0.00	0.0%
13		**	Mercury Vapor 8,600 lu 175 watts		$4.14	$4.14	$0.00	0.0%
14		**	Mercury Vapor 11,500 lu 250 watts		$5.76	$5.75	($0.01)	-0.2%
15		**	Mercury Vapor 21,500 lu 400 watts		$7.42	$7.42	$0.00	0.0%
18								
19			Energy Only	kWh				
20			Sodium Vapor 6,300 lu 70 watts	29	$0.89	$0.89	$0.00	0.0%
21			Sodium Vapor 9,500 lu 100 watts	41	$1.26	$1.26	$0.00	0.0%
22			Sodium Vapor 16,000 lu 150 watts	60	$1.84	$1.84	$0.00	0.0%
23			Sodium Vapor 22,000 lu 200 watts	88	$2.70	$2.69	($0.01)	-0.4%
24			Sodium Vapor 50,000 lu 400 watts	168	$5.15	$5.14	($0.01)	-0.2%
26		**	Sodium Vapor 27,500 lu 250 watts	116	$3.55	$3.55	$0.00	0.0%
27		**	Sodium Vapor 140,000 lu 1,000 watts	411	$12.59	$12.58	($0.01)	-0.1%
28		**	Mercury Vapor 6,000 lu 140 watts	62	$1.90	$1.90	$0.00	0.0%
29		**	Mercury Vapor 8,600 lu 175 watts	77	$2.36	$2.36	$0.00	0.0%
30		**	Mercury Vapor 11,500 lu 250 watts	104	$3.19	$3.18	($0.01)	-0.3%
31		**	Mercury Vapor 21,500 lu 400 watts	160	$4.90	$4.90	$0.00	0.0%
34								
35			Non-Fuel Energy (¢ per kWh)		3.063	3.061	(0.002)	-0.1%
36								
37								
38			Note: The monthly Relamp and Energy charge is calculated by adding the Relamp increase to the Energy-only increase avoiding rounding issues.					
39			**Note: These units are closed to new Company installations.					
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LINE NO.	(1) RATE SCHEDULE	(2) TYPE OF CHARGE	(3) MAY 1, 2020 PROPOSED RATE*	(4) JANUARY 1, 2021 PROPOSED RATE	(5) TOTAL CHANGE IN RATE	(6) % CHANGE IN RATE
1	SL-1	Street Lighting (continued))				
2		Other Charges				
3		Wood Pole	$5.24	$5.24	$0.00	0.0%
4		Concrete Pole / Steel Pole	$7.16	$7.16	$0.00	0.0%
5		Fiberglass Pole	$8.48	$8.47	($0.01)	-0.1%
6		Underground conductors not under paving (¢ per foot)	4.053	4.051	(0.002)	0.0%
7		Underground conductors under paving (¢ per foot)	9.903	9.897	(0.006)	-0.1%
8						
9		Willful Damage				
10		Cost for Shield upon second occurrence	$280.00	$280.00	$0.00	0.0%
11						
12	SL-1M	Street Lighting				
13						
14		Customer Charge/Minimum	$14.89	$14.88	($0.01)	-0.1%
15		Base Energy Charge (¢ per kWh)	3.007	3.005	(0.002)	-0.1%
16						
17						
18						
19	PL-1	Premium Lighting				
20		Present Value Revenue Requirement				
21		Multiplier	1.1961	1.1961	0.000	0.0%
22						
23		Monthly Rate				
24		Facilities (Percentage of total work order cost)				
25		10 Year Payment Option	1.364%	1.364%	0.000	0.0%
26		20 Year Payment Option	0.926%	0.926%	0.000	0.0%
27						
28		Maintenance	FPL's estimated cost of maintaining facilities			
29						
30						
31		Termination Factors				
32		10 Year Payment Option				
33		1	1.1961	1.1961	0.000	0.0%
34		2	1.0324	1.0324	0.000	0.0%
35		3	0.9489	0.9489	0.000	0.0%
36		4	0.8590	0.8590	0.000	0.0%
37		5	0.7621	0.7621	0.000	0.0%
38		6	0.6576	0.6576	0.000	0.0%
39						
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42						

LINE NO.	(1) RATE SCHEDULE	(2) TYPE OF CHARGE		(3) MAY 1, 2020 PROPOSED RATE*	(4) JANUARY 1, 2021 PROPOSED RATE	(5) TOTAL CHANGE IN RATE	(6) % CHANGE IN RATE
1	PL-1	Premium Lighting (continued)					
2			7	0.5450	0.5450	0.000	0.0%
3			8	0.4237	0.4237	0.000	0.0%
4			9	0.2929	0.2929	0.000	0.0%
5			10	0.1519	0.1519	0.000	0.0%
6			>10	0.0000	0.0000	0.000	
7							
8		20 Year Payment Option					
9			1	1.1961	1.1961	0.000	0.0%
10			2	1.0850	1.0850	0.000	0.0%
11			3	1.0582	1.0582	0.000	0.0%
12			4	1.0293	1.0293	0.000	0.0%
13			5	0.9982	0.9982	0.000	0.0%
14			6	0.9646	0.9646	0.000	0.0%
15			7	0.9285	0.9285	0.000	0.0%
16			8	0.8895	0.8895	0.000	0.0%
17			9	0.8475	0.8475	0.000	0.0%
18			10	0.8023	0.8023	0.000	0.0%
19			11	0.7535	0.7535	0.000	0.0%
20			12	0.7009	0.7009	0.000	0.0%
21			13	0.6443	0.6443	0.000	0.0%
22			14	0.5832	0.5832	0.000	0.0%
23			15	0.5174	0.5174	0.000	0.0%
24			16	0.4465	0.4465	0.000	0.0%
25			17	0.3700	0.3700	0.000	0.0%
26			18	0.2876	0.2876	0.000	0.0%
27			19	0.1988	0.1988	0.000	0.0%
28			20	0.1031	0.1031	0.000	0.0%
29			>20	0.0000	0.0000	0.000	
30							
31		Non-Fuel Energy (¢ per kWh)		3.063	3.061	(0.002)	-0.1%
32							
33		Willful Damage					
34		All occurrences after initial repair		Cost for repair or replacement			
35							
36	RL-1	Recreational Lighting [Schedule closed to new customers]					
37							
38		Non-Fuel Energy (¢ per kWh)		Otherwise applicable General			
39				Service Rate			
40							
41		Maintenance		FPL's estimated cost of maintaining facilities			
42							

LINE NO.	(1) RATE SCHEDULE		(2) TYPE OF CHARGE		(3) MAY 1, 2020 PROPOSED RATE*	(4) JANUARY 1, 2021 PROPOSED RATE	(5) TOTAL CHANGE IN RATE	(6) % CHANGE IN RATE
1	OL-1		Outdoor Lighting					
2			Charges for FPL-Owned Units					
3			Fixture					
4			Sodium Vapor 6,300 lu 70 watts		$5.38	$5.38	$0.00	0.0%
5			Sodium Vapor 9,500 lu 100 watts		$5.49	$5.49	$0.00	0.0%
6			Sodium Vapor 16,000 lu 150 watts		$5.68	$5.68	$0.00	0.0%
7			Sodium Vapor 22,000 lu 200 watts		$8.26	$8.26	$0.00	0.0%
8			Sodium Vapor 50,000 lu 400 watts		$8.81	$8.80	($0.01)	-0.1%
9		**	Sodium Vapor 12,000 lu 150 watts		$5.68	$5.68	$0.00	0.0%
10		**	Mercury Vapor 6,000 lu 140 watts		$4.13	$4.13	$0.00	0.0%
11		**	Mercury Vapor 8,600 lu 175 watts		$4.15	$4.15	$0.00	0.0%
12		**	Mercury Vapor 21,500 lu 400 watts		$6.80	$6.80	$0.00	0.0%
13								
14			Maintenance					
15			Sodium Vapor 6,300 lu 70 watts		$2.03	$2.03	$0.00	0.0%
16			Sodium Vapor 9,500 lu 100 watts		$2.03	$2.03	$0.00	0.0%
17			Sodium Vapor 16,000 lu 150 watts		$2.07	$2.07	$0.00	0.0%
18			Sodium Vapor 22,000 lu 200 watts		$2.65	$2.65	$0.00	0.0%
19			Sodium Vapor 50,000 lu 400 watts		$2.61	$2.61	$0.00	0.0%
20		**	Sodium Vapor 12,000 lu 150 watts		$2.07	$2.07	$0.00	0.0%
21		**	Mercury Vapor 6,000 lu 140 watts		$1.81	$1.81	$0.00	0.0%
22		**	Mercury Vapor 8,600 lu 175 watts		$1.81	$1.81	$0.00	0.0%
23		**	Mercury Vapor 21,500 lu 400 watts		$2.55	$2.55	$0.00	0.0%
24								
25			Energy Non-Fuel	kWh				
26			Sodium Vapor 6,300 lu 70 watts	29	$0.95	$0.95	0.00	0.0%
27			Sodium Vapor 9,500 lu 100 watts	41	$1.34	$1.34	0.00	0.0%
28			Sodium Vapor 16,000 lu 150 watts	60	$1.96	$1.96	0.00	0.0%
29			Sodium Vapor 22,000 lu 200 watts	88	$2.88	$2.88	0.00	0.0%
30			Sodium Vapor 50,000 lu 400 watts	168	$5.49	$5.49	0.00	0.0%
31		**	Sodium Vapor 12,000 lu 150 watts	60	$1.96	$1.96	0.00	0.0%
32		**	Mercury Vapor 6,000 lu 140 watts	62	$2.03	$2.03	0.00	0.0%
33		**	Mercury Vapor 8,600 lu 175 watts	77	$2.52	$2.52	0.00	0.0%
34		**	Mercury Vapor 21,500 lu 400 watts	160	$5.23	$5.23	0.00	0.0%
35								
36								
37								
38								
39								
40								
41								
42			Note: The monthly Relamp and Energy charge is calculated by adding the Relamp increase to the Energy-only increase avoiding rounding issues.					
			**Note: These units are closed to new Company installations.					

	(1)		(2)		(3)	(4)	(5)	(6)
LINE NO.	RATE SCHEDULE		TYPE OF CHARGE		MAY 1, 2020 PROPOSED RATE*	JANUARY 1, 2021 PROPOSED RATE	TOTAL CHANGE IN RATE	% CHANGE IN RATE
1	OL-1		Outdoor Lighting (continued)					
2			Charges for Customer Owned Units					
3			Total Charge-Relamping & Energy					
4			Sodium Vapor 6,300 lu 70 watts		$2.93	$2.93	$0.00	0.0%
5			Sodium Vapor 9,500 lu 100 watts		$3.32	$3.32	$0.00	0.0%
6			Sodium Vapor 16,000 lu 150 watts		$3.97	$3.97	$0.00	0.0%
7			Sodium Vapor 22,000 lu 200 watts		$5.47	$5.47	$0.00	0.0%
8			Sodium Vapor 50,000 lu 400 watts		$8.03	$8.03	$0.00	0.0%
9		**	Sodium Vapor 12,000 lu 150 watts		$4.26	$4.26	$0.00	0.0%
10		**	Mercury Vapor 6,000 lu 140 watts		$3.80	$3.80	$0.00	0.0%
11		**	Mercury Vapor 8,600 lu 175 watts		$4.29	$4.29	$0.00	0.0%
12		**	Mercury Vapor 21,500 lu 400 watts		$7.72	$7.72	$0.00	0.0%
13								
14			Energy Only	kWh				
15			Sodium Vapor 6,300 lu 70 watts	29	$0.95	$0.95	$0.00	0.0%
16			Sodium Vapor 9,500 lu 100 watts	41	$1.34	$1.34	$0.00	0.0%
17			Sodium Vapor 16,000 lu 150 watts	60	$1.96	$1.96	$0.00	0.0%
18			Sodium Vapor 22,000 lu 200 watts	88	$2.88	$2.88	$0.00	0.0%
19			Sodium Vapor 50,000 lu 400 watts	168	$5.49	$5.49	$0.00	0.0%
20		**	Sodium Vapor 12,000 lu 150 watts	60	$1.96	$1.96	$0.00	0.0%
21		**	Mercury Vapor 6,000 lu 140 watts	62	$2.03	$2.03	$0.00	0.0%
22		**	Mercury Vapor 8,600 lu 175 watts	77	$2.52	$2.52	$0.00	0.0%
23		**	Mercury Vapor 21,500 lu 400 watts	160	$5.23	$5.23	$0.00	0.0%
24								
25			Non-Fuel Energy (¢ per kWh)		3.270	3.268	(0.002)	-0.1%
26								
27			Other Charges					
28			Wood Pole		$11.84	$11.83	($0.01)	-0.1%
29			Concrete Pole / Steel Pole		$16.00	$15.99	($0.01)	-0.1%
30			Fiberglass Pole		$18.80	$18.79	($0.01)	-0.1%
31			Underground conductors excluding					
32			Trenching per foot		$0.091	$0.091	$0.000	0.0%
33			Down-guy, Anchor and Protector		$10.77	$10.76	($0.01)	-0.1%
34								
35	SL-2		Traffic Signal Service					
36			Minimum Charge at each point		$3.43	$3.43	$0.00	0.0%
37			Base Energy Charge (¢ per kWh)		5.015	5.012	(0.003)	-0.1%
38								
39	SL-2M		Traffic Signal Service					
40			Customer Charge/Minimum		$6.38	$6.38	$0.00	0.0%
41			Base Energy Charge (¢ per kWh)		4.873	4.870	(0.003)	-0.1%
42								

**Note: These units are closed to new Company installations.

LINE NO.	(1) RATE SCHEDULE	(2) TYPE OF CHARGE	(3) MAY 1, 2020 PROPOSED RATE*	(4) JANUARY 1, 2021 PROPOSED RATE	(5) TOTAL CHANGE IN RATE	(6) % CHANGE IN RATE
1	SST-1	Standby and Supplemental Service				
2		Customer Charge				
3		SST-1(D1)	$132.74	$132.66	($0.08)	-0.1%
4		SST-1(D2)	$132.74	$132.66	($0.08)	-0.1%
5		SST-1(D3)	$451.32	$451.05	($0.27)	-0.1%
6		SST-1(T)	$1,913.84	$1,912.71	($1.13)	-0.1%
7						
8		Distribution Demand $/kW Contract Standby Demand				
9		SST-1(D1)	$3.18	$3.18	$0.00	0.0%
10		SST-1(D2)	$3.18	$3.18	$0.00	0.0%
11		SST-1(D3)	$3.18	$3.18	$0.00	0.0%
12		SST-1(T)	N/A	N/A	N/A	N/A
13						
14		Reservation Demand $/kW				
15		SST-1(D1)	$1.57	$1.57	$0.00	0.0%
16		SST-1(D2)	$1.57	$1.57	$0.00	0.0%
17		SST-1(D3)	$1.57	$1.57	$0.00	0.0%
18		SST-1(T)	$1.43	$1.43	$0.00	0.0%
19						
20		Daily Demand (On-Peak) $/kW				
21		SST-1(D1)	$0.76	$0.76	$0.00	0.0%
22		SST-1(D2)	$0.76	$0.76	$0.00	0.0%
23		SST-1(D3)	$0.76	$0.76	$0.00	0.0%
24		SST-1(T)	$0.45	$0.45	$0.00	0.0%
25						
26		Supplemental Service				
27		Demand	Otherwise Applicable Rate			
28		Energy	Otherwise Applicable Rate			
29						
30		Non-Fuel Energy - On-Peak (¢ per kWh)				
31		SST-1(D1)	0.756	0.756	0.000	0.0%
32		SST-1(D2)	0.756	0.756	0.000	0.0%
33		SST-1(D3)	0.756	0.756	0.000	0.0%
34		SST-1(T)	0.753	0.753	0.000	0.0%
35		Non-Fuel Energy - Off-Peak (¢ per kWh)				
36		SST-1(D1)	0.756	0.756	0.000	0.0%
37		SST-1(D2)	0.756	0.756	0.000	0.0%
38		SST-1(D3)	0.756	0.756	0.000	0.0%
39		SST-1(T)	0.753	0.753	0.000	0.0%
40						
41						
42						

LINE NO.	(1) RATE SCHEDULE	(2) TYPE OF CHARGE	(3) MAY 1, 2020 PROPOSED RATE*	(4) JANUARY 1, 2021 PROPOSED RATE	(5) TOTAL CHANGE IN RATE	(6) % CHANGE IN RATE
1	ISST-1	Interruptible Standby and Supplemental Service				
2		Customer Charge				
3		Distribution	$451.32	$451.05	($0.27)	-0.1%
4		Transmission	$1,913.84	$1,912.71	($1.13)	-0.1%
5						
6		Distribution Demand				
7		Distribution	$3.18	$3.18	$0.00	0.0%
8		Transmission	N/A	N/A	N/A	N/A
9						
10		Reservation Demand-Interruptible				
11		Distribution	$0.27	$0.27	$0.00	0.0%
12		Transmission	$0.31	$0.31	$0.00	0.0%
13						
14		Reservation Demand-Firm				
15		Distribution	$1.57	$1.57	$0.00	0.0%
16		Transmission	$1.43	$1.43	$0.00	0.0%
17						
18		Supplemental Service				
19		Demand	Otherwise Applicable Rate			
20		Energy	Otherwise Applicable Rate			
21						
22		Daily Demand (On-Peak) Firm Standby				
23		Distribution	$0.76	$0.76	$0.00	0.0%
24		Transmission	$0.45	$0.45	$0.00	0.0%
25						
26		Daily Demand (On-Peak) Interruptible Standby				
27		Distribution	$0.13	$0.13	$0.00	0.0%
28		Transmission	$0.12	$0.12	$0.00	0.0%
29						
30		Non-Fuel Energy - On-Peak (¢ per kWh)				
31		Distribution	0.756	0.756	0.000	0.0%
32		Transmission	0.753	0.753	0.000	0.0%
33		Non-Fuel Energy - Off-Peak (¢ per kWh)				
34		Distribution	0.756	0.756	0.000	0.0%
35		Transmission	0.753	0.753	0.000	0.0%
36						
37		Excess "Firm Standby Demand"	Difference between reservation charge for			
38		¤ Up to prior 60 months of service	firm and interruptible standby demand			
39			times excess demand			
40						
41						
42		¤ Penalty Charge per kW for each month of rebilling	$1.14	$1.14	$0.00	0.0%

LINE NO.	(1) RATE SCHEDULE	(2) TYPE OF CHARGE	(3) MAY 1, 2020 PROPOSED RATE*	(4) JANUARY 1, 2021 PROPOSED RATE	(5) TOTAL CHANGE IN RATE	(6) % CHANGE IN RATE
1	TR	Transformation Rider				
2		Transformer Credit				
3		(per kW of Billing Demand)	($0.15)	($0.15)	$0.00	0.0%
4						
5						
6	GSCU-1	General Service constant Usage				
7		Customer Charge:	$14.86	$14.85	($0.01)	-0.1%
8						
9		Non-Fuel Energy Charges:				
10		Base Energy Charge*	3.730	3.728	(0.002)	-0.1%
11		* The fuel and non-fuel energy charges will be assessed on the Constant Usage kWh				
12						
13						
14	HLFT-1	High Load Factor - Time of Use				
15		Customer Charge:				
16		21 - 499 kW:	$26.50	$26.48	($0.02)	-0.1%
17		500 - 1,999 kW	$79.45	$79.40	($0.05)	-0.1%
18		2,000 kW or greater	$238.17	$238.03	($0.14)	-0.1%
19						
20		Demand Charges:				
21		On-peak Demand Charge:				
22		21 - 499 kW:	$11.76	$11.75	($0.01)	-0.1%
23		500 - 1,999 kW	$12.81	$12.80	($0.01)	-0.1%
24		2,000 kW or greater	$12.90	$12.89	($0.01)	-0.1%
25						
26		Maximum Demand Charge:				
27		21 - 499 kW:	$2.44	$2.44	$0.00	0.0%
28		500 - 1,999 kW	$2.75	$2.75	$0.00	0.0%
29		2,000 kW or greater	$2.74	$2.74	$0.00	0.0%
30						
31		Non-Fuel Energy Charges: (¢ per kWh)				
32		On-Peak Period				
33		21 - 499 kW:	1.922	1.921	(0.001)	-0.1%
34		500 - 1,999 kW	1.134	1.133	(0.001)	-0.1%
35		2,000 kW or greater	1.008	1.007	(0.001)	-0.1%
36						
37						
38						
39						
40						
41						
42						

LINE NO.	(1) RATE SCHEDULE	(2) TYPE OF CHARGE	(3) MAY 1, 2020 PROPOSED RATE*	(4) JANUARY 1, 2021 PROPOSED RATE	(5) TOTAL CHANGE IN RATE	(6) % CHANGE IN RATE
1	HLFT-1	High Load Factor - Time of Use (continued)				
2		Off-Peak Period				
3		21 - 499 kW:	1.199	1.198	(0.001)	-0.1%
4		500 - 1,999 kW	1.084	1.083	(0.001)	-0.1%
5		2,000 kW or greater	1.000	0.999	(0.001)	-0.1%
6						
7						
8	SDTR	Seasonal Demand – Time of Use Rider				
9		Option A				
10		Customer Charge:				
11		21 - 499 kW:	$26.50	$26.48	($0.02)	-0.1%
12		500 - 1,999 kW	$79.45	$79.40	($0.05)	-0.1%
13		2,000 kW or greater	$238.17	$238.03	($0.14)	-0.1%
14						
15		Demand Charges:				
16		Seasonal On-peak Demand:				
17		21 - 499 kW:	$11.03	$11.02	($0.01)	-0.1%
18		500 - 1,999 kW	$12.60	$12.59	($0.01)	-0.1%
19		2,000 kW or greater	$13.20	$13.19	($0.01)	-0.1%
20						
21		Non-seasonal Demand Max Demand:				
22		21 - 499 kW:	$9.54	$9.53	($0.01)	-0.1%
23		500 - 1,999 kW	$11.97	$11.96	($0.01)	-0.1%
24		2,000 kW or greater	$12.46	$12.45	($0.01)	-0.1%
25						
26		Energy Charges (¢ per kWh):				
27		Seasonal On-peak Energy:				
28		21 - 499 kW:	8.835	8.830	(0.005)	-0.1%
29		500 - 1,999 kW	6.245	6.241	(0.004)	-0.1%
30		2,000 kW or greater	4.955	4.952	(0.003)	-0.1%
31						
32		Seasonal Off-peak Energy:				
33		21 - 499 kW:	1.594	1.593	(0.001)	-0.1%
34		500 - 1,999 kW	1.266	1.265	(0.001)	-0.1%
35		2,000 kW or greater	1.237	1.236	(0.001)	-0.1%
36						
37		Non-seasonal Energy				
38		21 - 499 kW:	2.222	2.221	(0.001)	0.0%
39		500 - 1,999 kW	1.755	1.754	(0.001)	-0.1%
40		2,000 kW or greater	1.579	1.578	(0.001)	-0.1%
41						
42						

LINE NO.	(1) RATE SCHEDULE	(2) TYPE OF CHARGE	(3) MAY 1, 2020 PROPOSED RATE*	(4) JANUARY 1, 2021 PROPOSED RATE	(5) TOTAL CHANGE IN RATE	(6) % CHANGE IN RATE
1	SDTR	Seasonal Demand – Time of Use Rider (continued)				
2		Option B				
3		Customer Charge:				
4		21 - 499 kW:	$26.50	$26.48	($0.02)	-0.1%
5		500 - 1,999 kW	$79.45	$79.40	($0.05)	-0.1%
6		2,000 kW or greater	$238.17	$238.03	($0.14)	-0.1%
7						
8		Demand Charges:				
9		Seasonal On-peak Demand:				
10		21 - 499 kW:	$11.03	$11.02	($0.01)	-0.1%
11		500 - 1,999 kW	$12.60	$12.59	($0.01)	-0.1%
12		2,000 kW or greater	$13.20	$13.19	($0.01)	-0.1%
13						
14		Non-seasonal On-peak Demand:				
15		21 - 499 kW:	$9.54	$9.53	($0.01)	-0.1%
16		500 - 1,999 kW	$11.97	$11.96	($0.01)	-0.1%
17		2,000 kW or greater	$12.46	$12.45	($0.01)	-0.1%
18						
19		Energy Charges (¢ per kWh):				
20		Seasonal On-peak Energy:				
21		21 - 499 kW:	8.835	8.830	(0.005)	-0.1%
22		500 - 1,999 kW	6.245	6.241	(0.004)	-0.1%
23		2,000 kW or greater	4.955	4.952	(0.003)	-0.1%
24						
25		Seasonal Off-peak Energy:				
26		21 - 499 kW:	1.594	1.593	(0.001)	-0.1%
27		500 - 1,999 kW	1.266	1.265	(0.001)	-0.1%
28		2,000 kW or greater	1.237	1.236	(0.001)	-0.1%
29						
30		Non-seasonal On-peak Energy:				
31		21 - 499 kW:	5.049	5.046	(0.003)	-0.1%
32		500 - 1,999 kW	3.738	3.736	(0.002)	-0.1%
33		2,000 kW or greater	3.411	3.409	(0.002)	-0.1%
34						
35		Non-seasonal Off-peak Energy:				
36		21 - 499 kW:	1.594	1.593	(0.001)	-0.1%
37		500 - 1,999 kW	1.266	1.265	(0.001)	-0.1%
38		2,000 kW or greater	1.237	1.236	(0.001)	-0.1%
39						
40						
41						
42						

LINE NO.	(1) RATE SCHEDULE	(2) TYPE OF CHARGE		(3) MAY 1, 2020 PROPOSED RATE*	(4) JANUARY 1, 2021 PROPOSED RATE	(5) TOTAL CHANGE IN RATE	(6) % CHANGE IN RATE
1	NSMR	Non-Standard Meter Rate					
2							
3		Enrollment Fee					
4		GS-1		$89.00	$89.00	$0.00	0.0%
5		GSD-1		$89.00	$89.00	$0.00	0.0%
6		RS-1		$89.00	$89.00	$0.00	0.0%
7							
8		Monthly Surcharge					
9		GS-1		$13.00	$13.00	$0.00	0.0%
10		GSD-1		$13.00	$13.00	$0.00	0.0%
11		RS-1		$13.00	$13.00	$0.00	0.0%
12							
13							
14	LT-1	LED Lighting Pilot					
15		LED Fixtures					
16		Fixture Tier	Energy Tier				
17		1	A	$1.50	$1.50	$0.00	0.0%
18		1	B	$1.70	$1.70	$0.00	0.0%
19		1	C	$1.90	$1.90	$0.00	0.0%
20		1	D	$2.10	$2.10	$0.00	0.0%
21		1	E	$2.30	$2.30	$0.00	0.0%
22		1	F	$2.50	$2.50	$0.00	0.0%
23		1	G	$2.70	$2.70	$0.00	0.0%
24		1	H	$2.90	$2.90	$0.00	0.0%
25		1	I	$3.10	$3.10	$0.00	0.0%
26		1	J	$3.30	$3.30	$0.00	0.0%
27		1	K	$3.50	$3.50	$0.00	0.0%
28		1	L	$3.70	$3.70	$0.00	0.0%
29		1	M	$3.90	$3.90	$0.00	0.0%
30		1	N	$4.10	$4.10	$0.00	0.0%
31		1	O	$4.30	$4.30	$0.00	0.0%
32		1	P	$4.50	$4.50	$0.00	0.0%
33		1	Q	$4.70	$4.70	$0.00	0.0%
34		1	R	$4.90	$4.90	$0.00	0.0%
35		1	S	$5.10	$5.10	$0.00	0.0%
36		1	T	$5.30	$5.30	$0.00	0.0%
37		2	A	$4.50	$4.50	$0.00	0.0%
38		2	B	$4.70	$4.70	$0.00	0.0%
39		2	C	$4.90	$4.90	$0.00	0.0%
40		2	D	$5.10	$5.10	$0.00	0.0%
41		2	E	$5.30	$5.30	$0.00	0.0%
42		2	F	$5.50	$5.50	$0.00	0.0%

LINE NO.	(1) RATE SCHEDULE	(2) TYPE OF CHARGE		(3) MAY 1, 2020 PROPOSED RATE*	(4) JANUARY 1, 2021 PROPOSED RATE	(5) TOTAL CHANGE IN RATE	(6) % CHANGE IN RATE
1	LT-1	LED Lighting Pilot (continued)					
2		2	G	$5.70	$5.70	$0.00	0.0%
3		2	H	$5.90	$5.90	$0.00	0.0%
4		2	I	$6.10	$6.10	$0.00	0.0%
5		2	J	$6.30	$6.30	$0.00	0.0%
6		2	K	$6.50	$6.50	$0.00	0.0%
7		2	L	$6.70	$6.70	$0.00	0.0%
8		2	M	$6.90	$6.90	$0.00	0.0%
9		2	N	$7.10	$7.10	$0.00	0.0%
10		2	O	$7.30	$7.30	$0.00	0.0%
11		2	P	$7.50	$7.50	$0.00	0.0%
12		2	Q	$7.70	$7.70	$0.00	0.0%
13		2	R	$7.90	$7.90	$0.00	0.0%
14		2	S	$8.10	$8.10	$0.00	0.0%
15		2	T	$8.30	$8.30	$0.00	0.0%
16		3	A	$7.50	$7.50	$0.00	0.0%
17		3	B	$7.70	$7.70	$0.00	0.0%
18		3	C	$7.90	$7.90	$0.00	0.0%
19		3	D	$8.10	$8.10	$0.00	0.0%
20		3	E	$8.30	$8.30	$0.00	0.0%
21		3	F	$8.50	$8.50	$0.00	0.0%
22		3	G	$8.70	$8.70	$0.00	0.0%
23		3	H	$8.90	$8.90	$0.00	0.0%
24		3	I	$9.10	$9.10	$0.00	0.0%
25		3	J	$9.30	$9.30	$0.00	0.0%
26		3	K	$9.50	$9.50	$0.00	0.0%
27		3	L	$9.70	$9.70	$0.00	0.0%
28		3	M	$9.90	$9.90	$0.00	0.0%
29		3	N	$10.10	$10.10	$0.00	0.0%
30		3	O	$10.30	$10.30	$0.00	0.0%
31		3	P	$10.50	$10.50	$0.00	0.0%
32		3	Q	$10.70	$10.70	$0.00	0.0%
33		3	R	$10.90	$10.90	$0.00	0.0%
34		3	S	$11.10	$11.10	$0.00	0.0%
35		3	T	$11.30	$11.30	$0.00	0.0%
36		4	A	$10.50	$10.50	$0.00	0.0%
37		4	B	$10.70	$10.70	$0.00	0.0%
38		4	C	$10.90	$10.90	$0.00	0.0%
39		4	D	$11.10	$11.10	$0.00	0.0%
40		4	E	$11.30	$11.30	$0.00	0.0%
41		4	F	$11.50	$11.50	$0.00	0.0%
42		4	G	$11.70	$11.70	$0.00	0.0%

LINE NO.	(1) RATE SCHEDULE	(2) TYPE OF CHARGE		(3) MAY 1, 2020 PROPOSED RATE*	(4) JANUARY 1, 2021 PROPOSED RATE	(5) TOTAL CHANGE IN RATE	(6) % CHANGE IN RATE
1	LT-1	LED Lighting Pilot (continued)					
2		4	H	$11.90	$11.90	$0.00	0.0%
3		4	I	$12.10	$12.10	$0.00	0.0%
4		4	J	$12.30	$12.30	$0.00	0.0%
5		4	K	$12.50	$12.50	$0.00	0.0%
6		4	L	$12.70	$12.70	$0.00	0.0%
7		4	M	$12.90	$12.90	$0.00	0.0%
8		4	N	$13.10	$13.10	$0.00	0.0%
9		4	O	$13.30	$13.30	$0.00	0.0%
10		4	P	$13.50	$13.50	$0.00	0.0%
11		4	Q	$13.70	$13.70	$0.00	0.0%
12		4	R	$13.90	$13.90	$0.00	0.0%
13		4	S	$14.10	$14.10	$0.00	0.0%
14		4	T	$14.30	$14.30	$0.00	0.0%
15		5	A	$13.50	$13.50	$0.00	0.0%
16		5	B	$13.70	$13.70	$0.00	0.0%
17		5	C	$13.90	$13.90	$0.00	0.0%
18		5	D	$14.10	$14.10	$0.00	0.0%
19		5	E	$14.30	$14.30	$0.00	0.0%
20		5	F	$14.50	$14.50	$0.00	0.0%
21		5	G	$14.70	$14.70	$0.00	0.0%
22		5	H	$14.90	$14.90	$0.00	0.0%
23		5	I	$15.10	$15.10	$0.00	0.0%
24		5	J	$15.30	$15.30	$0.00	0.0%
25		5	K	$15.50	$15.50	$0.00	0.0%
26		5	L	$15.70	$15.70	$0.00	0.0%
27		5	M	$15.90	$15.90	$0.00	0.0%
28		5	N	$16.10	$16.10	$0.00	0.0%
29		5	O	$16.30	$16.30	$0.00	0.0%
30		5	P	$16.50	$16.50	$0.00	0.0%
31		5	Q	$16.70	$16.70	$0.00	0.0%
32		5	R	$16.90	$16.90	$0.00	0.0%
33		5	S	$17.10	$17.10	$0.00	0.0%
34		5	T	$17.30	$17.30	$0.00	0.0%
35		6	A	$16.50	$16.50	$0.00	0.0%
36		6	B	$16.70	$16.70	$0.00	0.0%
37		6	C	$16.90	$16.90	$0.00	0.0%
38		6	D	$17.10	$17.10	$0.00	0.0%
39		6	E	$17.30	$17.30	$0.00	0.0%
40		6	F	$17.50	$17.50	$0.00	0.0%
41		6	G	$17.70	$17.70	$0.00	0.0%
42		6	H	$17.90	$17.90	$0.00	0.0%

LINE NO.	(1) RATE SCHEDULE	(2) TYPE OF CHARGE		(3) MAY 1, 2020 PROPOSED RATE*	(4) JANUARY 1, 2021 PROPOSED RATE	(5) TOTAL CHANGE IN RATE	(6) % CHANGE IN RATE
	LT-1	LED Lighting Pilot (continued)					
1		6	I	$18.10	$18.10	$0.00	0.0%
2		6	J	$18.30	$18.30	$0.00	0.0%
3		6	K	$18.50	$18.50	$0.00	0.0%
4		6	L	$18.70	$18.70	$0.00	0.0%
5		6	M	$18.90	$18.90	$0.00	0.0%
6		6	N	$19.10	$19.10	$0.00	0.0%
7		6	O	$19.30	$19.30	$0.00	0.0%
8		6	P	$19.50	$19.50	$0.00	0.0%
9		6	Q	$19.70	$19.70	$0.00	0.0%
10		6	R	$19.90	$19.90	$0.00	0.0%
11		6	S	$20.10	$20.10	$0.00	0.0%
12		6	T	$20.30	$20.30	$0.00	0.0%
13		7	A	$19.50	$19.50	$0.00	0.0%
14		7	B	$19.70	$19.70	$0.00	0.0%
15		7	C	$19.90	$19.90	$0.00	0.0%
16		7	D	$20.10	$20.10	$0.00	0.0%
17		7	E	$20.30	$20.30	$0.00	0.0%
18		7	F	$20.50	$20.50	$0.00	0.0%
19		7	G	$20.70	$20.70	$0.00	0.0%
20		7	H	$20.90	$20.90	$0.00	0.0%
21		7	I	$21.10	$21.10	$0.00	0.0%
22		7	J	$21.30	$21.30	$0.00	0.0%
23		7	K	$21.50	$21.50	$0.00	0.0%
24		7	L	$21.70	$21.70	$0.00	0.0%
25		7	M	$21.90	$21.90	$0.00	0.0%
26		7	N	$22.10	$22.10	$0.00	0.0%
27		7	O	$22.30	$22.30	$0.00	0.0%
28		7	P	$22.50	$22.50	$0.00	0.0%
29		7	Q	$22.70	$22.70	$0.00	0.0%
30		7	R	$22.90	$22.90	$0.00	0.0%
31		7	S	$23.10	$23.10	$0.00	0.0%
32		7	T	$23.30	$23.30	$0.00	0.0%
33		8	A	$22.50	$22.50	$0.00	0.0%
34		8	B	$22.70	$22.70	$0.00	0.0%
35		8	C	$22.90	$22.90	$0.00	0.0%
36		8	D	$23.10	$23.10	$0.00	0.0%
37		8	E	$23.30	$23.30	$0.00	0.0%
38		8	F	$23.50	$23.50	$0.00	0.0%
39		8	G	$23.70	$23.70	$0.00	0.0%
40		8	H	$23.90	$23.90	$0.00	0.0%
41		8	I	$24.10	$24.10	$0.00	0.0%
42		8	J	$24.30	$24.30	$0.00	0.0%

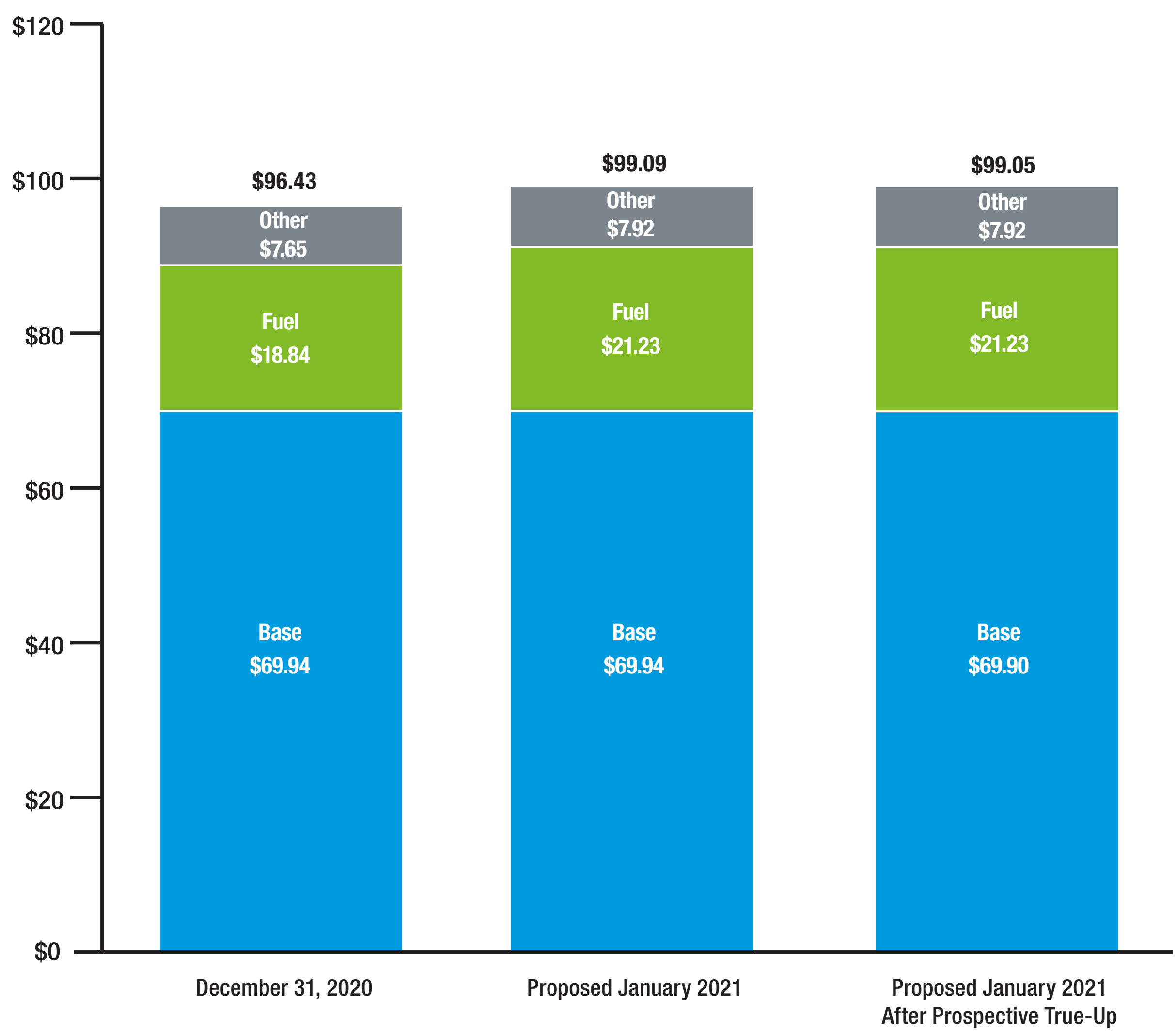
LINE NO.	(1) RATE SCHEDULE	(2) TYPE OF CHARGE		(3) MAY 1, 2020 PROPOSED RATE*	(4) JANUARY 1, 2021 PROPOSED RATE	(5) TOTAL CHANGE IN RATE	(6) % CHANGE IN RATE
	LT-1	LED Lighting Pilot (continued)					
1		8	K	$24.50	$24.50	$0.00	0.0%
2		8	L	$24.70	$24.70	$0.00	0.0%
3		8	M	$24.90	$24.90	$0.00	0.0%
4		8	N	$25.10	$25.10	$0.00	0.0%
5		8	O	$25.30	$25.30	$0.00	0.0%
6		8	P	$25.50	$25.50	$0.00	0.0%
7		8	Q	$25.70	$25.70	$0.00	0.0%
8		8	R	$25.90	$25.90	$0.00	0.0%
9		8	S	$26.10	$26.10	$0.00	0.0%
10		8	T	$26.30	$26.30	$0.00	0.0%
11		9	A	$25.50	$25.50	$0.00	0.0%
12		9	B	$25.70	$25.70	$0.00	0.0%
13		9	C	$25.90	$25.90	$0.00	0.0%
14		9	D	$26.10	$26.10	$0.00	0.0%
15		9	E	$26.30	$26.30	$0.00	0.0%
16		9	F	$26.50	$26.50	$0.00	0.0%
17		9	G	$26.70	$26.70	$0.00	0.0%
18		9	H	$26.90	$26.90	$0.00	0.0%
19		9	I	$27.10	$27.10	$0.00	0.0%
20		9	J	$27.30	$27.30	$0.00	0.0%
21		9	K	$27.50	$27.50	$0.00	0.0%
22		9	L	$27.70	$27.70	$0.00	0.0%
23		9	M	$27.90	$27.90	$0.00	0.0%
24		9	N	$28.10	$28.10	$0.00	0.0%
25		9	O	$28.30	$28.30	$0.00	0.0%
26		9	P	$28.50	$28.50	$0.00	0.0%
27		9	Q	$28.70	$28.70	$0.00	0.0%
28		9	R	$28.90	$28.90	$0.00	0.0%
29		9	S	$29.10	$29.10	$0.00	0.0%
30		9	T	$29.30	$29.30	$0.00	0.0%
31		10	A	$28.50	$28.50	$0.00	0.0%
32		10	B	$28.70	$28.70	$0.00	0.0%
33		10	C	$28.90	$28.90	$0.00	0.0%
34		10	D	$29.10	$29.10	$0.00	0.0%
35		10	E	$29.30	$29.30	$0.00	0.0%
36		10	F	$29.50	$29.50	$0.00	0.0%
37		10	G	$29.70	$29.70	$0.00	0.0%
38		10	H	$29.90	$29.90	$0.00	0.0%
39		10	I	$30.10	$30.10	$0.00	0.0%
40		10	J	$30.30	$30.30	$0.00	0.0%
41		10	K	$30.50	$30.50	$0.00	0.0%
42		10	L	$30.70	$30.70	$0.00	0.0%

LINE NO.	(1) RATE SCHEDULE	(2) TYPE OF CHARGE		(3) MAY 1, 2020 PROPOSED RATE*	(4) JANUARY 1, 2021 PROPOSED RATE	(5) TOTAL CHANGE IN RATE	(6) % CHANGE IN RATE
	LT-1	LED Lighting Pilot (continued)					
1		10	M	$30.90	$30.90	$0.00	0.0%
2		10	N	$31.10	$31.10	$0.00	0.0%
3		10	O	$31.30	$31.30	$0.00	0.0%
4		10	P	$31.50	$31.50	$0.00	0.0%
5		10	Q	$31.70	$31.70	$0.00	0.0%
6		10	R	$31.90	$31.90	$0.00	0.0%
7		10	S	$32.10	$32.10	$0.00	0.0%
8		10	T	$32.30	$32.30	$0.00	0.0%
9							
10							
11		Energy Tier Charges					
12			Energy Tier				
13			A	$0.00	$0.00	$0.00	0.0%
14			B	$0.20	$0.20	$0.00	0.0%
15			C	$0.40	$0.40	$0.00	0.0%
16			D	$0.60	$0.60	$0.00	0.0%
17			E	$0.80	$0.80	$0.00	0.0%
18			F	$1.00	$1.00	$0.00	0.0%
19			G	$1.20	$1.20	$0.00	0.0%
20			H	$1.40	$1.40	$0.00	0.0%
21			I	$1.60	$1.60	$0.00	0.0%
22			J	$1.80	$1.80	$0.00	0.0%
23			K	$2.00	$2.00	$0.00	0.0%
24			L	$2.20	$2.20	$0.00	0.0%
25			M	$2.40	$2.40	$0.00	0.0%
26			N	$2.60	$2.60	$0.00	0.0%
27			O	$2.80	$2.80	$0.00	0.0%
28			P	$3.00	$3.00	$0.00	0.0%
29			Q	$3.20	$3.20	$0.00	0.0%
30			R	$3.40	$3.40	$0.00	0.0%
31			S	$3.60	$3.60	$0.00	0.0%
32			T	$3.80	$3.80	$0.00	0.0%
33							
34		Non-Fuel Energy (¢ per kWh)		3.063	3.061	(0.002)	-0.1%
35							
36							
37		Charges for Maintenance and Conversion Recovery:					
38		Maintenance per Fixture (FPL Owned Fixture and Pole)		$1.29	$1.29	$0.00	0.0%
39		Maintenance per Fixture for FPL Fixtures on Customer Pole		$1.03	$1.03	$0.00	0.0%
40		LED Conversion Recovery		$1.87	$1.87	$0.00	0.0%
41							
42		Charges for Other FPL-Owned Facilities:					
43		Wood pole used only for the street lighting system		$5.24	$5.24	$0.00	0.0%
44		Standard Concrete pole used only for the street lighting system		$7.16	$7.16	$0.00	0.0%
45		Round Fiberglass pole used only for the street lighting system		$8.48	$8.47	($0.01)	-0.1%
46		Decorative Tall Fiberglass pole used only for the street lighting system		$17.89	$17.88	($0.01)	-0.1%
47		Decorative Concrete pole used only for the street lighting system		$14.53	$14.52	($0.01)	-0.1%
48		Underground conductors (¢ per foot)		4.053	4.051	(0.002)	0.0%

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20200001-EI EXHIBIT: 26
PARTY: FLORIDA POWER & LIGHT COMPANY – DIRECT
DESCRIPTION: E.J. Anderson EJA-5

Typical 1,000-kWh Residential Customer Bill Comparison

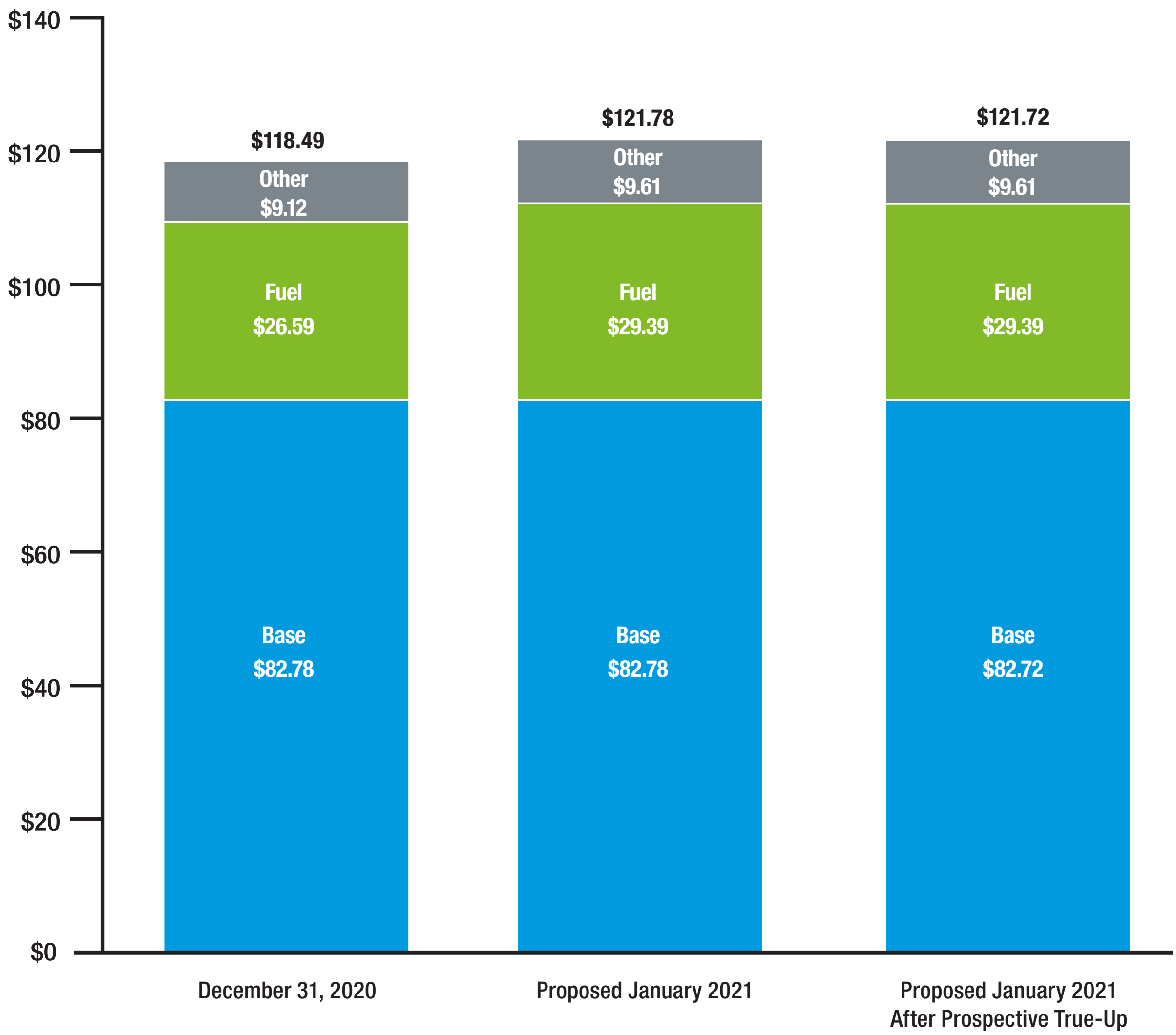
RS-1 Rate



The December 2020 bill reflects approved rates effective for December 2020. The 2021 bill estimates include projected 2021 rates for fuel, capacity, environmental, conservation, and storm protection plan; proposed Prospective True-Up rate adjustments; and the state gross receipts tax. Estimates do not include credits, local taxes or fees that may be applicable in some jurisdictions. All rates are subject to change and must be approved by the Florida Public Service Commission before implementation.

1,200-kWh Commercial Customer Bill Comparison (non-demand)

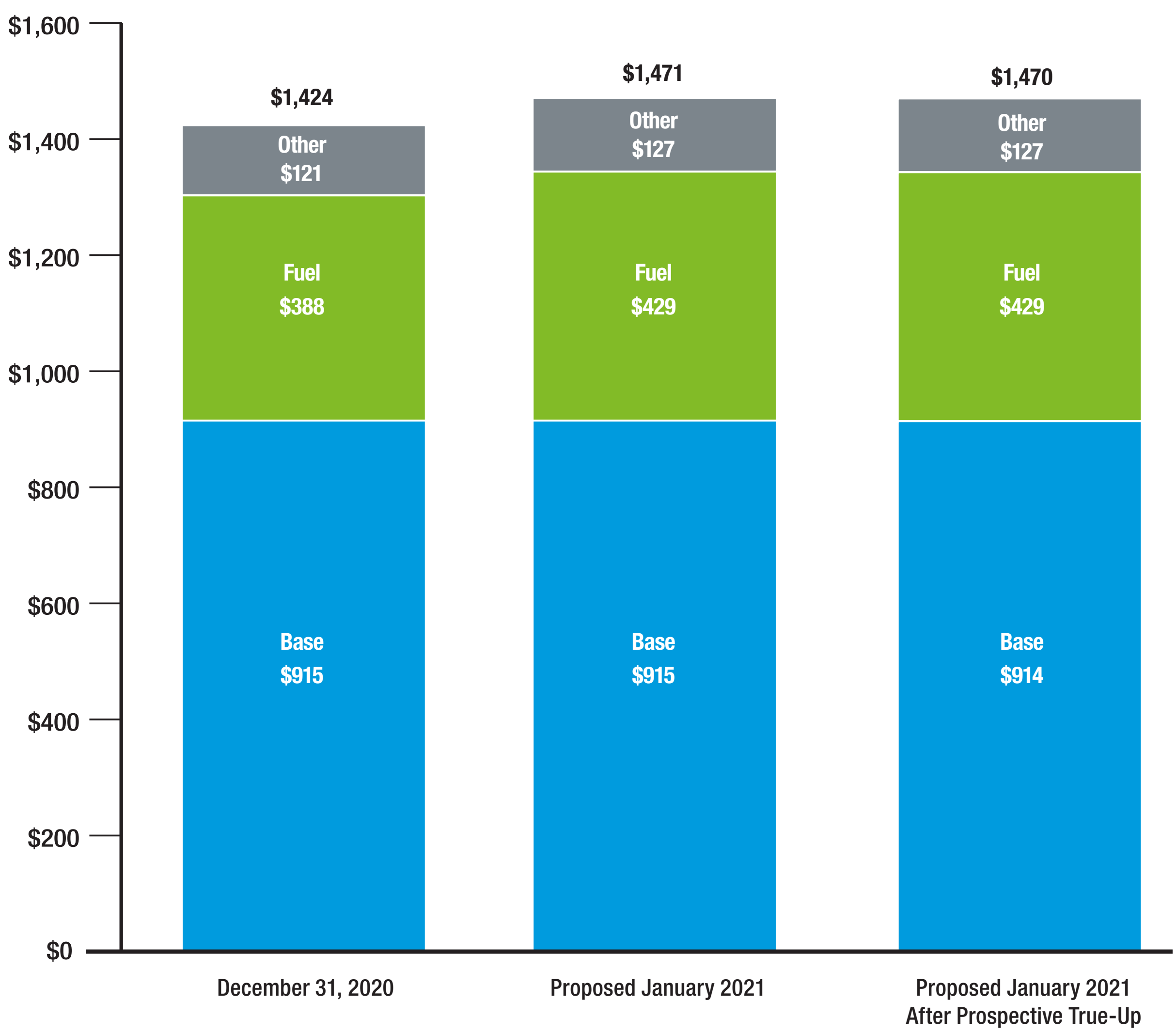
GS-1 Rate



The December 2020 bill reflects approved rates effective for December 2020. The 2021 bill estimates include projected 2021 rates for fuel, capacity, environmental, conservation, and storm protection plan; proposed Prospective True-Up rate adjustments; and the state gross receipts tax. Estimates do not include credits, local taxes or fees that may be applicable in some jurisdictions. All rates are subject to change and must be approved by the Florida Public Service Commission before implementation.

17,520-kWh Commercial Customer Bill Comparison

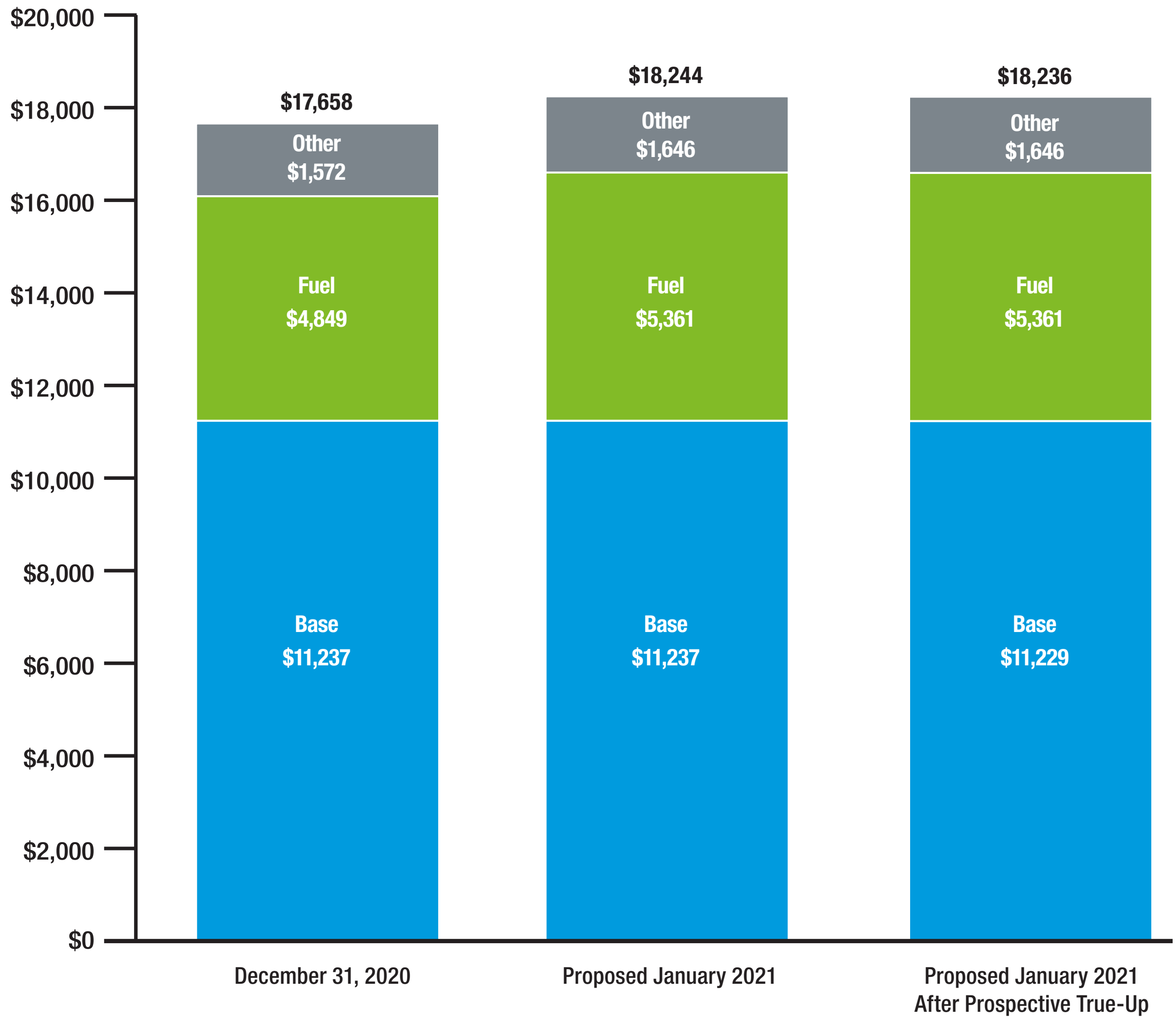
GSD-1 Rate 50 kW, 48% load factor



The December 2020 bill reflects approved rates effective for December 2020. The 2021 bill estimates include projected 2021 rates for fuel, capacity, environmental, conservation, and storm protection plan; proposed Prospective True-Up rate adjustments; and the state gross receipts tax. Estimates do not include credits, local taxes or fees that may be applicable in some jurisdictions. All rates are subject to change and must be approved by the Florida Public Service Commission before implementation.

219,000-kWh Commercial Customer Bill Comparison

GSLD-1 Rate 600 kW, 50% load factor



The December 2020 bill reflects approved rates effective for December 2020. The 2021 bill estimates include projected 2021 rates for fuel, capacity, environmental, conservation, and storm protection plan; proposed Prospective True-Up rate adjustments; and the state gross receipts tax. Estimates do not include credits, local taxes or fees that may be applicable in some jurisdictions. All rates are subject to change and must be approved by the Florida Public Service Commission before implementation.

1,124,200-kWh Commercial Customer Bill Comparison

GSLD-2 Rate 2,800 kW, 55% load factor

The December 2020 bill reflects approved rates effective for December 2020. The 2021 bill estimates include projected 2021 rates for fuel, capacity, environmental, conservation, and storm protection plan; proposed Prospective True-Up rate adjustments; and the state gross receipts tax. Estimates do not include credits, local taxes or fees that may be applicable in some jurisdictions. All rates are subject to change and must be approved by the Florida Public Service Commission before implementation.

Schedule A

FLORIDA PUBLIC UTILITIES
FINAL FUEL AND PURCHASED POWER OVER/(UNDER) RECOVERY
FOR THE PERIOD
JANUARY 2019 THROUGH DECEMBER 2019

CONSOLIDATED ELECTRIC DIVISION

1	JURISDICTIONAL FUEL COSTS (INCL. ALL ADJUSTMENTS)	$	55,932,828
2	JURISDICTIONAL FUEL REVENUES APPLICABLE TO THE PERIOD		57,165,517
3	ACTUAL OVER/(UNDER) RECOVERED FUEL COSTS FOR THE PERIOD		1,232,689
4	ADJUSTMENTS (INCL. REVENUE REFUND TRUE-UP ADJUSTMENT)*		(3,957,772)
5	INTEREST		(53,633)
6	TRUE-UP COLLECTED		3,957,772
7	PRIOR PERIOD TRUE-UP (ACTUAL ENDING 12/18)		(1,482,331)
8	ACTUAL OVER/(UNDER) RECOVERY FOR THE PERIOD (LINE 3 + LINE4 + LINE5 + LINE6 + LINE7)		(303,275)
9	PROJECTED UNDER-RECOVERY PER PROJECTION FILED 7/26/19		(1,934,452)
10	**FINAL FUEL OVER/(UNDER) RECOVERY (LINE 8 - LINE 9)**	**$**	**1,631,177**

Exhibit No.________________
DOCKET NO. 20200001-EI
Florida Public Utilities Company
(CDY - 1)
Page 1 of 3

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20200001-EI EXHIBIT: 27
PARTY: FLORIDA PUBLIC UTILITIES COMPANY – DIRECT
DESCRIPTION: Curtis D. Young CDY-1

FLORIDA PUBLIC UTILITIES COMPANY

Schedule E-1B

CALCULATION OF PURCHASED POWER COSTS AND CALCULATION OF TRUE-UP AND INTEREST PROVISION-EXCLUDING GSLD1

ACTUAL/ESTIMATED FOR THE PERIOD: JANUARY 2019 THROUGH DECEMBER 2019

BASED ON SIX MONTHS ACTUAL AND SIX MONTHS ESTIMATED

(EXCLUDES LINE LOSS , EXCLUDES TAXES)

CONSOLIDATED

	ACTUAL Jan 2019	ACTUAL Feb 2019	ACTUAL Mar 2019	ACTUAL Apr 2019	ACTUAL May 2019	ACTUAL Jun 2019	Estimated Jul 2019	Estimated Aug 2019	Estimated Sep 2019	Estimated Oct 2019	Estimated Nov 2019	Estimated Dec 2019	Total
Total System Sales - KWH	49,458,300	50,689,267	36,576,538	43,490,580	49,217,862	63,808,711	63,677,740	63,802,881	63,357,176	51,437,255	46,883,116	50,997,866	633,397,292
West-Rock Purchases - KWH	1,100,000	1,660,000	700,000	1,180,000	910,000	590,000	700,000	400,000	700,000	900,000	500,000	700,000	10,040,000
Rayonier Purchases - KWH - On Peak	257,138	17,375	405,716	503,036	325,908	140,022	310,500	310,500	310,500	310,500	310,500	310,500	3,512,195
Rayonier Purchases - KWH - Off Peak	314,524	46,414	738,955	1,096,759	781,238	259,760	589,500	589,500	589,500	589,500	589,500	589,500	6,774,650
Eight Flags Purchases - KWH - KWH	13,766,429	9,583,689	17,099,478	16,306,914	16,338,420	15,285,031	12,500,000	12,800,000	12,400,000	15,500,000	15,200,000	15,800,000	172,579,961
FPL Purchases - KWH	15,952,593	12,110,849	6,435,820	6,170,899	15,062,347	20,482,838	26,467,386	26,219,853	25,566,924	16,965,475	12,211,924	10,368,183	194,015,090
Gulf Purchases - KWH	24,797,417	18,315,462	20,326,293	19,981,205	27,436,089	29,167,339	31,306,575	31,361,913	31,523,953	27,134,816	23,151,348	23,385,966	307,888,377
Generation Demand - KW - FPL	53,591	47,104	38,957	35,824	51,457	74,600	65,500	68,900	56,400	49,500	47,300	46,700	635,833
Generation Demand - KW - Gulf	91,000	91,000	91,000	91,000	91,000	91,000	91,000	91,000	91,000	91,000	91,000	91,000	1,092,000
Transmission Demand - KW - FPL	-	33,272	39,339	53,184	60,712	81,794	69,000	72,400	59,900	53,000	50,800	50,200	623,601
Transmission Demand - KW - Southern	57,049	55,832	54,695	54,739	54,857	55,436	55,500	55,500	55,500	55,500	55,500	55,500	665,608
Purchased Power Rates:													
West Rock Fuel Costs - $/KWH	0.03612	0.03476	0.03189	0.03189	0.03259	0.03758	0.04221	0.04221	0.04221	0.04221	0.04221	0.04221	
Rayonier Energy Charge - On Peak - $/KWH	0.02914	0.02914	0.02914	0.05842	0.06717	0.03090	0.04964	0.04964	0.04964	0.04964	0.04964	0.04964	
Rayonier Energy Charge - Off Peak - $/KWH	0.02715	0.02715	0.02715	0.02550	0.02866	0.02866	0.04964	0.04964	0.04964	0.04964	0.04964	0.04964	
Eight Flags Charge - $/KWH	0.09196	0.08392	0.06745	0.07641	0.07494	0.07655	0.08382	0.08382	0.08382	0.08382	0.08382	0.08382	
Base Fuel Costs - $/KWH - FPL	0.03446	0.03057	0.02961	0.02674	0.03021	0.02936	0.03573	0.03569	0.03588	0.03554	0.03459	0.03006	
Base Fuel Costs - $/KWH GULF 0.974	0.04836	0.04836	0.04836	0.04836	0.04836	0.04836	0.04836	0.04836	0.04836	0.04836	0.04836	0.04836	
Energy Charge - $/KWH - FPL	0.00182	0.00186	0.00217	0.00222	0.00189	0.00173	0.00161	0.00161	0.00159	0.00163	0.00172	0.00215	
Demand and Non-Fuel:													
Demand Charge - $/KW - FPL	6.85	7.04	7.37	7.54	6.90	6.37	6.59	6.54	6.78	6.96	7.03	7.05	
Demand Charge - $/KW - Gulf	12.80	12.80	12.80	12.80	12.80	12.80	12.80	12.80	12.80	12.80	12.80	12.80	
Distribution Facility Charge	84,253	84,253	84,253	84,253	84,253	84,253	84,253	84,253	84,253	84,253	84,253	84,253	
Transmission Charge $/KW - FPL	1.85	1.85	1.72	1.68	1.85	1.94	1.85	1.85	1.85	1.85	1.85	1.85	
Transmission Charge $/KW - Southern	3.01633	2.98080	3.03851	3.01615	2.41913	3.01633	3.01632	3.01632	3.01632	3.01632	3.01632	3.01632	
Purchased Power Costs:													
RockTenn Fuel Costs	39,736	57,706	22,322	37,628	29,655	22,175	29,549	16,885	29,549	37,991	21,106	29,549	373,851
Rayonier Standby Costs	16,032	1,766	31,885	57,355	44,282	11,772	44,676	44,676	44,676	44,676	44,676	44,676	431,148
Eight Flags	1,265,905	804,229	1,153,311	1,246,011	1,224,348	1,170,121	1,047,750	1,072,896	1,039,368	1,299,210	1,274,064	1,324,356	13,921,569
Gulf Base Fuel Costs	1,231,215	909,380	1,009,219	992,085	1,362,227	1,448,185	1,554,400	1,557,148	1,565,193	1,347,269	1,149,486	1,161,135	15,286,942
FPL Base Fuel Costs	549,787	370,283	190,554	164,999	455,064	601,329	945,744	935,724	917,269	602,992	422,426	311,625	6,467,796
FPL Fuel Adjustment	29,067	22,544	13,941	13,675	28,421	35,471	42,547	42,262	40,742	27,583	20,974	22,340	339,567
Subtotal Fuel Costs	3,131,742	2,165,908	2,421,232	2,511,753	3,143,997	3,289,053	3,664,666	3,669,591	3,636,797	3,359,721	2,932,732	2,893,681	36,820,872
Demand and Non-Fuel Costs: Demand Capacity Charge	1,531,632	1,496,279	1,451,876	1,434,801	1,520,001	1,639,912	1,596,535	1,615,065	1,546,940	1,509,335	1,497,345	1,494,075	18,333,796
Distr. Fac. Charge	84,253	84,253	84,253	84,253	84,253	84,253	84,253	84,253	84,253	84,253	84,253	84,253	1,011,034
FERC & Meter Reading	4,759	4,922	4,361	4,535	4,505	5,151	5,301	5,486	5,491	5,505	5,125	4,780	59,921
Transmission Charge	172,079	228,113	233,918	254,463	244,856	326,077	295,338	301,642	278,466	265,672	261,593	260,481	3,122,698
Subtotal Demand & Non-Fuel Costs	1,792,723	1,813,567	1,774,408	1,778,052	1,853,615	2,055,393	1,981,427	2,006,446	1,915,150	1,864,765	1,848,316	1,843,589	22,527,449
Total System Purchased Power Costs	4,924,465	3,979,475	4,195,640	4,289,805	4,997,611	5,344,446	5,646,093	5,676,037	5,551,947	5,224,486	4,781,048	4,737,270	59,348,321
Less Direct Billing To GSLD1 Class: Demand	52,290	50,467	30,568	43,957	43,015	43,310	29,138	29,138	29,138	29,138	29,138	29,138	438,435
Commodity	144,384	71,673	46,116	18,783	38,412	72,334	37,760	109,747	105,508	146,031	184,460	136,273	1,111,482
Net Purchased Power Costs	4,727,791	3,857,335	4,118,955	4,227,065	4,916,185	5,228,802	5,579,195	5,537,152	5,417,300	5,049,317	4,567,450	4,571,859	57,798,404
	0	0	0	0	0	0	0	0	0	0	0	0	0
Special Costs*	64,554	6,129	41,721	42,872	(21,458)	26,992	17,850	17,850	19,300	17,850	17,850	20,300	271,810
Total Costs and Charges	4,792,344	3,863,464	4,160,676	4,269,936	4,894,727	5,255,794	5,597,045	5,555,002	5,436,600	5,067,167	4,585,300	4,592,159	58,070,214
Sales Revenues - Fuel Adjustment Revenues:													
RS< 0.09519	1,721,442	1,816,047	1,448,522	1,473,399	1,634,896	1,911,278	1,894,713	1,902,854	1,883,244	1,682,192	1,532,262	1,637,722	20,538,571
RS> 0.10768	690,876	519,744	272,802	283,241	584,259	1,250,725	1,372,118	1,275,915	1,212,310	719,689	381,418	558,229	9,121,326
GS 0.09557	369,597	375,162	324,303	350,150	418,030	546,639	538,885	561,497	547,987	439,185	416,165	456,730	5,344,330
GSD 0.09134	1,101,938	1,058,108	940,923	1,081,551	1,243,996	1,492,030	1,481,341	1,527,685	1,540,933	1,324,892	1,283,035	1,366,724	15,443,156
GSLD 0.08836	592,770	543,460	291,781	744,502	615,851	668,297	671,180	643,917	682,334	577,219	556,411	551,994	7,139,716
LS 0.06947	42,490	43,467	42,483	44,681	44,245	44,483	43,715	43,550	43,723	43,387	43,204	43,117	522,545
Unbilled Fuel Revenues	(2,250,523)	1,183,425	(1,189,949)	1,195,138	(600,560)	861,574	62,500	62,500	62,500	62,500	62,500	62,500	(425,895)
Total Fuel Revenues (Excl. GSLD1)	2,268,590	5,539,413	2,130,865	5,172,662	3,940,717	6,775,026	6,064,452	6,017,918	5,973,031	4,849,064	4,274,995	4,677,016	57,683,749
GSLD1 Fuel .17197	196,674	122,140	76,684	62,740	81,427	115,644	66,898	138,885	134,646	175,169	213,598	165,411	1,549,917
Non-Fuel Revenues	6,618,334	2,155,388	1,718,849	1,946,086	1,605,871	2,807,026	3,167,224	2,975,578	2,546,304	1,941,858	2,369,448	2,711,799	32,563,765
Total Sales Revenue	9,083,598	7,816,942	3,926,398	7,181,488	5,628,015	9,697,695	9,298,575	9,132,381	8,653,981	6,966,091	6,858,040	7,554,226	91,797,431
KWH Sales: RS<	17,664,507	17,628,817	15,210,704	15,450,076	17,143,105	20,078,126	19,904,234	19,989,756	19,783,747	17,671,667	16,096,633	17,204,508	213,825,879
RS>	6,414,274	6,059,209	2,533,093	2,630,335	5,441,828	11,614,936	12,742,260	11,848,861	11,258,197	6,683,439	3,542,065	5,184,033	85,952,530
GS	3,865,037	3,924,910	3,389,224	3,660,161	4,370,380	5,722,667	5,638,572	5,875,171	5,733,805	4,595,374	4,354,505	4,778,952	55,908,758
GSD	12,075,157	11,550,441	10,309,238	11,796,013	13,626,164	16,346,585	16,217,127	16,724,484	16,869,517	14,504,381	14,046,153	14,962,351	169,027,611
GSLD	6,708,857	7,150,768	3,302,316	8,107,502	6,970,084	7,563,654	7,596,285	7,287,725	7,722,525	6,532,847	6,297,347	6,247,361	81,487,271
GSLD1	2,100,000	3,750,000	1,210,000	1,210,000	1,030,000	1,840,000	950,000	1,450,000	1,360,000	825,000	1,924,500	2,000,000	19,649,500
LS	630,468	625,122	621,963	636,493	636,300	642,743	629,262	626,884	629,385	624,546	621,914	620,663	7,545,744
Total KWH Sales	49,458,300	50,689,267	36,576,538	43,490,580	49,217,862	63,808,711	63,677,740	63,802,881	63,357,176	51,437,255	46,883,116	50,997,866	633,397,292
True-up Calculation (Excl. GSLD1):													
Fuel Revenues	2,268,590	5,539,413	2,130,865	5,172,662	3,940,717	6,775,026	6,064,452	6,017,918	5,973,031	4,849,064	4,274,995	4,677,016	57,683,749
True-up Provision - collect/(refund)	329,814	329,814	329,814	329,814	329,814	329,814	329,814	329,814	329,814	329,814	329,814	329,818	3,957,772
Gross Receipts Tax Refund													0
Fuel Revenue	1,938,776	5,209,599	1,801,051	4,842,848	3,610,903	6,445,212	5,734,638	5,688,104	5,643,217	4,519,250	3,945,181	4,347,198	53,725,977
Net Purchased Power and Other Fuel Costs	4,792,344	3,863,464	4,160,676	4,269,936	4,894,727	5,255,794	5,597,045	5,555,002	5,436,600	5,067,167	4,585,300	4,592,159	58,070,214
True-up Provision for the Period	(2,853,569)	1,346,135	(2,359,625)	572,912	(1,283,824)	1,189,418	137,593	133,102	206,617	(547,917)	(640,119)	(244,961)	(4,344,236)
Interest Provision for the Period	(5,626)	(6,401)	(6,785)	(7,937)	(7,989)	(7,218)	(5,287)	(4,387)	(3,417)	(3,112)	(3,635)	(3,863)	(65,657)
Beginning of Period True-up and Interest Provision	(1,482,331)	(4,011,712)	(2,342,163)	(4,378,759)	(3,483,971)	(4,445,969)	(2,933,955)	(2,471,835)	(2,013,305)	(1,480,292)	(1,701,507)	(2,015,447)	(1,482,331)
True-up Collected or (Refunded)	329,814	329,814	329,814	329,814	329,814	329,814	329,814	329,814	329,814	329,814	329,814	329,818	3,957,772
Adjustment for Tax Settlement													0
End of Period, Net True-up and Int. Prov.	(4,011,712)	(2,342,163)	(4,378,759)	(3,483,971)	(4,445,969)	(2,933,955)	(2,471,835)	(2,013,305)	(1,480,292)	(1,701,507)	(2,015,447)	(1,934,452)	(1,934,452)
Beginning True-up Amount	(1,482,331)	(4,011,712)	(2,342,163)	(4,378,759)	(3,483,971)	(4,445,969)	(2,933,955)	(2,471,835)	(2,013,305)	(1,480,292)	(1,701,507)	(2,015,447)	
Ending True-up Amount Before Interest	(4,006,086)	(2,335,762)	(4,371,974)	(3,476,034)	(4,437,980)	(2,926,737)	(2,466,548)	(2,008,918)	(1,476,875)	(1,698,395)	(2,011,812)	(1,930,589)	Interest Provision: -3.26%
Total Beginning and Ending True-up	(5,488,417)	(6,347,474)	(6,714,138)	(7,854,793)	(7,921,951)	(7,372,707)	(5,400,503)	(4,480,753)	(3,490,180)	(3,178,686)	(3,713,318)	(3,946,036)	
Average True-up Amount	(2,744,208)	(3,173,737)	(3,357,069)	(3,927,397)	(3,960,975)	(3,686,353)	(2,700,252)	(2,240,377)	(1,745,090)	(1,589,343)	(1,856,659)	(1,973,018)	
Average Annual Interest Rate	2.4600%	2.4200%	2.4250%	2.4250%	2.4200%	2.3500%	2.3500%	2.3500%	2.3500%	2.3500%	2.3500%	2.3500%	
Interest Provision	(5,626)	(6,401)	(6,785)	(7,937)	(7,989)	(7,218)	(5,287)	(4,387)	(3,417)	(3,112)	(3,635)	(3,863)	

* Includes: Consulting fees, Legal fees and Taxes on Company Use.

Exhibit No.______

DOCKET NO. 20200001-EI

Florida Public Utilities Company

(CDY - 1)

FLORIDA PUBLIC UTILITIES COMPANY

Schedule C1

CALCULATION OF PURCHASED POWER COSTS AND CALCULATION OF TRUE-UP AND INTEREST PROVISION-EXCLUDING GSLD1

ACTUAL/ESTIMATED FOR THE PERIOD: JANUARY 2019 THROUGH DECEMBER 2019

BASED ON TWELVE MONTHS ACTUAL

(EXCLUDES LINE LOSS , EXCLUDES TAXES)

		2019												
		ACTUAL JANUARY	ACTUAL FEBRUARY	ACTUAL MARCH	ACTUAL APRIL	ACTUAL MAY	ACTUAL JUNE	ACTUAL JULY	ACTUAL AUGUST	ACTUAL SEPTEMBER	ACTUAL OCTOBER	ACTUAL NOVEMBER	ACTUAL DECEMBER	Total
Total System Sales - KWH		49,458,300	50,689,267	36,576,538	43,490,580	49,217,862	63,808,711	64,186,190	66,332,353	68,018,741	59,329,907	52,674,410	44,852,001	648,634,860
WEST-ROCK Purchases - KWH		1,100,000	1,660,000	700,000	1,180,000	910,000	590,000	250,000	640,000	490,000	200,000	470,000	160,000	8,350,000
Rayonier Purchases - KWH - On Peak		257,138	17,375	405,716	503,036	325,908	140,022	97,768	93,088	118,468	29,562	69,110	169,237	2,226,428
Rayonier Purchases - KWH - Off Peak		314,524	46,414	738,955	1,096,759	781,238	259,760	565,429	374,970	404,387	121,125	160,235	213,926	5,077,722
Eight Flags Purchases-KWH		13,766,429	9,583,689	17,099,478	16,306,914	16,338,420	15,285,031	15,679,438	14,562,658	14,129,633	16,008,664	15,872,542	16,007,818	180,640,714
FPL Purchases - KWH - BLOCK		9,214,593	7,377,849	5,488,820	5,262,601	8,879,291	9,575,032	10,288,262	10,350,198	9,812,952	7,812,000	6,063,275	7,190,664	97,315,537
FPL Purchases - KWH - LOAD		6,738,000	4,733,000	947,000	908,298	6,183,056	10,907,806	12,819,399	12,963,484	12,082,612	9,724,636	732,037	984,164	79,723,492
Gulf Purchases - KWH		24,797,417	18,315,462	20,326,293	19,981,205	27,436,089	29,167,339	29,873,744	30,998,485	30,184,127	25,472,261	21,089,819	22,542,758	300,184,999
FPL Billing Demand - KW - BLOCK		14,000	14,000	14,000	14,000	14,000	14,000	14,000	14,000	14,000	14,000	14,000	14,000	168,000
FPL Billing Demand - KW - LOAD		39,591	33,104	24,957	21,824	37,457	60,600	51,281	56,951	61,781	34,501	23,088	23,523	468,658
FPL BULK Transmission Demand - KW		0	33,272	39,339	53,184	60,712	81,794	78,850	64,269	70,950	48,501	49,355	37,897	618,123
System Billing Demand - Gulf KW		91,000	91,000	91,000	91,000	91,000	91,000	91,000	91,000	91,000	91,000	91,000	91,000	1,092,000
Peak Billing Demand- Southern KW		57,049	55,832	54,695	54,739	54,857	55,436	56,470	56,283	54,945	55,162	55,213	55,842	666,523
Purchased Power Rates:														
WestRock Fuel Costs - $/KWH		0.03612	0.03476	0.03189	0.03189	0.03259	0.03758	0.03176	0.03071	0.03386	0.03669	0.02676	0.02390	
Rayonier -Energy Charge- On Peak - $/KWH		0.02914	0.02914	0.02914	0.05842	0.06717	0.03090	0.03090	0.03592	0.03592	0.03287	0.03491	0.03491	
Rayonier- Energy Charge - Off Peak - $/KWH		0.02715	0.02715	0.02715	0.02550	0.02866	0.02866	0.03592	0.03309	0.03035	0.02937	0.03248	0.03248	
Eight Flags Purchases-$/KWH		0.09196	0.08392	0.06745	0.07641	0.07494	0.07655	0.07315	0.07924	0.07027	0.07369	0.07750	0.07458	
FPL Fuel - BLOCK	0.9815	0.02844	0.02569	0.02740	0.02503	0.02526	0.02348	0.02339	0.02260	0.02512	0.02730	0.02271	0.01992	
FPL VOM - BLOCK	0.9815	0.00235	0.00235	0.00235	0.00240	0.00240	0.00240	0.00240	0.00240	0.00240	0.00240	0.00240	0.00240	
FPL Fuel - LOAD	0.9815	0.04270	0.03818	0.04240	0.03664	0.03732	0.03452	0.03454	0.03328	0.03694	0.04017	0.03552	0.03134	
FPL VOM - LOAD	0.9815	0.00110	0.00110	0.00110	0.00115	0.00115	0.00115	0.00115	0.00115	0.00115	0.00115	0.00115	0.00115	
FPL Demand and Non-Fuel:														
Demand Charge - $/KW - BLOCK		10.79	10.79	10.79	10.79	10.79	10.79	10.79	10.79	10.79	10.79	10.70	10.70	
Demand Charge - $/KW - LOAD		5.45	5.45	5.45	5.45	5.45	5.45	5.45	5.45	5.45	5.45	5.25	5.25	
Bulk Transmission Charge $/KW		1.85408	1.85408	1.85408	1.85408	1.85408	1.85408	1.85408	1.85408	1.85408	1.85408	1.85408	1.85408	
Gulf Energy Environmental Line Loss Fctr	0.97400	0.04836	0.04836	0.04836	0.04836	0.04836	0.04836	0.04836	0.04836	0.04836	0.04836	0.04836	0.04836	
Gulf Fuel Demand and Non-Fuel:														
Capacity Charge-$/KW		12.80000	12.80000	12.80000	12.80000	12.80000	12.80000	12.80000	12.80000	12.80000	12.80000	12.80000	12.80000	
Transmission and Interconnection		3.01632	3.01632	3.01632	3.01632	3.01632	3.01632	3.01632	3.01632	3.01632	3.01632	3.01632	3.01632	
FERC and Attachment K Costs		0.0000866	0.0000866	0.0000866	0.0000866	0.0000866	0.0000866	0.0000866	0.0000866	0.0000866	0.0000866	0.0000813	0.0000813	
Purchased Power Costs: WestRock Fuel Costs		39,736	57,706	22,322	37,628	29,655	22,175	7,940	19,652	16,591	7,339	12,575	3,825	277,144
Rayonier Standby Costs		16,032	1,766	31,885	57,355	44,282	11,772	23,331	15,752	16,527	4,529	7,617	12,856	243,704
Eight Flags Fuel Costs		1,265,905	804,229	1,153,311	1,246,011	1,224,348	1,170,121	1,147,029	1,153,939	992,875	1,179,729	1,230,077	1,193,883	13,761,457
Gulf Base Fuel Costs		1,231,215	909,380	1,009,219	992,085	1,362,227	1,448,185	1,483,259	1,539,103	1,498,670	1,264,721	1,047,129	1,119,269	14,904,462
FPL Base Fuel Costs -Block		262,098	189,560	150,402	131,721	224,309	224,834	240,675	233,965	246,522	213,267	137,692	143,251	2,398,295
FPL Base Fuel Costs -Load		287,689	180,723	40,152	33,278	230,755	376,495	442,766	431,411	446,276	390,639	26,005	30,845	2,917,034
Subtotal Fuel Costs		3,102,675	2,143,364	2,407,291	2,498,078	3,115,575	3,253,582	3,345,000	3,393,822	3,217,461	3,060,224	2,461,095	2,503,929	34,502,096
Demand and Non-Fuel Costs: FPL Demand Charge-Block		151,060	151,060	151,060	151,060	151,060	148,415	151,060	151,060	151,060	151,060	149,800	149,800	1,807,555
FPL Demand Charge-Load		215,772	180,419	136,016	118,941	204,141	326,696	279,481	310,383	336,706	188,030	110,712	123,496	2,530,793
FPL Bulk Transmission Charg		0	61,689	67,727	89,363	112,150	158,864	152,145	135,925	131,420	89,925	90,651	69,407	1,159,266
FPL Customer Charge		2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	24,000
Gulf Capacity Charge		1,164,800	1,164,800	1,164,800	1,164,800	1,164,800	1,164,800	1,164,800	1,164,800	1,164,800	1,164,800	1,164,800	1,164,800	13,977,600
Gulf / FPL Transmission/Interc		172,079	166,424	166,191	165,101	132,706	167,213	170,330	135,056	165,481	166,386	166,540	168,437	1,941,944
Gulf / FPL Attch K &FERC		1,984	2,147	1,586	1,760	1,730	2,376	2,526	2,587	2,684	2,614	2,071	1,715	25,780
Souther Co. Distr Facility		84,253	84,253	84,253	84,253	84,253	84,253	84,253	84,253	84,253	84,253	84,253	84,253	1,011,034
Meter Reading and Processinc		775	775	775	775	775	775	775	775	775	775	775	775	9,300
FPL Intermediate Tier Costs		21,655	17,338	12,899	12,630	21,310	22,896	24,692	24,840	23,551	18,749	14,552	17,258	232,369
FPL Load Following Costs		7,412	5,206	1,042	1,045	7,111	12,575	14,742	14,908	13,895	11,183	842	1,132	91,093
														0
Subtotal Demand & Non-Fuel Costs		1,821,789	1,836,111	1,788,348	1,791,727	1,882,036	2,090,864	2,046,804	2,026,587	2,076,625	1,879,775	1,786,996	1,783,073	22,810,735
Total System Purchased Power Costs		4,924,464	3,979,474	4,195,640	4,289,805	4,997,611	5,344,446	5,391,804	5,420,409	5,294,086	4,940,000	4,248,091	4,287,002	57,312,832
Less Direct Billing To GSLD1 Class:	Demand	52,290	50,467	30,568	43,957	43,015	43,310	6,647	3,849	71,728	112,891	41,781	39,697	540,200
(these 2 amounts (Demand and comodity) should	Commodity	144,384	71,673	46,116	18,783	38,412	72,334	104,578	94,324	149,208	197,993	86,092	98,192	1,122,089
Net Purchased Power Costs		4,727,790	3,857,334	4,118,955	4,227,065	4,916,184	5,228,803	5,280,580	5,322,236	5,073,150	4,629,115	4,120,218	4,149,113	55,650,542
		0	0	0	0	0	0	0	0	0	0	0	0	0
Special Costs		64,554	6,129	41,721	42,872	(21,458)	26,992	24,625	125	24,143	1,230	21,200	50,152	282,285
Total Costs and Charges		4,792,343	3,863,464	4,160,676	4,269,937	4,894,726	5,255,795	5,305,206	5,322,361	5,097,293	4,630,345	4,141,418	4,199,265	55,932,828
Sales Revenues - Fuel Adjustment Revenues														
RS< 1,000 kwh	0.09519	1,721,442	1,816,047	1,448,522	1,473,399	1,634,896	1,911,278	1,931,630	1,932,583	1,935,579	1,827,521	1,616,490	1,597,607	20,846,994
RS> 1,000 kwh	0.10763	690,876	519,744	272,802	283,241	584,259	1,250,725	1,274,759	1,306,275	1,371,922	932,671	474,395	542,207	9,503,876
GS	0.09557	369,597	375,161	324,303	350,150	418,030	546,639	532,801	577,818	565,541	521,410	409,497	377,929	5,368,876
GSD	0.09134	1,101,938	1,058,108	940,923	1,081,551	1,243,996	1,492,030	1,434,146	1,538,634	1,586,594	1,344,907	1,224,229	1,056,437	15,103,493
GSLD	0.08836	592,770	543,460	291,781	744,502	615,851	668,297	645,009	679,159	737,176	591,481	741,457	549,681	7,400,624
LS	0.06947	42,490	43,467	42,483	44,681	44,245	44,483	44,099	43,967	35,884	43,951	43,275	43,072	516,097
Unbilled Fuel Revenues		(2,250,523)	1,183,425	(1,189,949)	1,195,138	(600,560)	861,574	36,925	(5,510)	(130,976)	(195,865)	(625,357)	147,234	(1,574,443)
Total Fuel Revenues (Excl. GSLD1)		2,268,590	5,539,412	2,130,865	5,172,662	3,940,717	6,775,026	5,899,369	6,072,927	6,101,720	5,066,076	3,883,986	4,314,167	57,165,517
GSLD1 Fuel Revenues		196,674	122,140	76,684	62,740	81,427	115,644	111,224	98,173	220,936	310,884	127,873	137,889	1,662,288
Non-Fuel Revenues		6,618,334	2,155,388	1,718,849	1,946,086	1,605,871	2,807,026	2,684,096	2,748,411	2,805,926	2,521,975	2,033,836	2,022,294	31,668,092
Total Sales Revenue		9,083,598	7,816,941	3,926,398	7,181,488	5,628,015	9,697,695	8,694,689	8,919,510	9,128,582	7,898,935	6,045,695	6,474,350	90,495,897
KWH Sales: RS< 1,000 kwh		17,664,507	17,628,817	15,210,704	15,450,076	17,143,105	20,078,126	20,215,232	20,291,774	20,320,498	19,189,768	16,964,505	16,783,923	216,941,034
RS> 1,000 kwh		6,414,274	6,059,209	2,533,093	2,630,335	5,441,828	11,614,936	11,838,132	12,130,807	12,740,440	8,661,306	4,405,493	5,035,234	89,505,087
GS		3,865,037	3,924,910	3,389,224	3,660,161	4,370,380	5,722,667	5,574,911	6,045,943	5,916,863	5,455,718	4,284,725	3,954,417	56,164,956
GSD		12,075,157	11,550,441	10,309,238	11,796,013	13,626,164	16,346,585	15,703,048	16,844,343	17,356,333	14,964,549	13,402,367	11,565,448	165,539,686
GSLD		6,708,857	7,150,768	3,302,316	8,107,502	6,970,084	7,563,654	7,300,084	7,686,590	8,343,216	6,694,269	8,391,667	6,223,564	84,442,571
GSLD1		2,100,000	3,750,000	1,210,000	1,210,000	1,030,000	1,840,000	2,920,000	2,700,000	2,700,000	3,730,000	4,598,000	662,000	28,450,000
LS		630,468	625,122	621,963	636,493	636,300	642,743	634,783	632,896	641,391	634,297	627,653	627,415	7,591,525
														0
Total KWH Sales		49,458,300	50,689,267	36,576,538	43,490,580	49,217,862	63,808,711	64,186,190	66,332,353	68,018,741	59,329,907	52,674,410	44,852,001	648,634,860
True-up Calculation (Excl. GSLD1):														
Fuel Revenues		2,268,590	5,539,412	2,130,865	5,172,662	3,940,717	6,775,026	5,899,369	6,072,927	6,101,720	5,066,076	3,883,986	4,314,167	57,165,517
True-up Provision - collect/(refund)		329,814	329,814	329,814	329,814	329,814	329,814	329,814	329,814	329,814	329,814	329,814	329,818	3,957,772
Gross Receipts Tax Refund		0	0	0	0	0	0	0						0
Fuel Revenue		1,938,776	5,209,598	1,801,051	4,842,848	3,610,903	6,445,212	5,569,555	5,743,113	5,771,906	4,736,262	3,554,172	3,984,349	53,207,745
Net Purchased Power and Other Fuel Costs		4,792,343	3,863,463.67	4,160,676	4,269,937	4,894,726	5,255,795	5,305,206	5,322,361	5,097,293	4,630,345	4,141,418	4,199,265	55,932,828
True-up Provision for the Period		(2,853,568)	1,346,135	(2,359,625)	572,911	(1,283,823)	1,189,418	264,349	420,752	674,613	105,917	(587,246)	(214,916)	(2,725,082)
Interest Provision for the Period		(5,626)	(6,401)	(6,785)	(7,937)	(7,989)	(7,218)	(4,934)	(3,472)	(1,826)	(572)	(393)	(480)	(53,633)
Beginning of Period True-up and Interest Provision		(1,482,331)	(4,011,711)	(2,342,163)	(4,378,759)	(3,483,971)	(4,445,969)	(2,933,955)	(2,344,726)	(1,597,632)	(595,031)	(159,871)	(417,696)	(1,482,331)
True-up Collected or (Refunded)		329,814	329,814	329,814	329,814	329,814	329,814	329,814	329,814	329,814	329,814	329,814	329,818	3,957,772
End of Period, Net True-up and Int Prov.		(4,011,711)	(2,342,163)	(4,378,759)	(3,483,971)	(4,445,969)	(2,933,955)	(2,344,726)	(1,597,632)	(595,031)	(159,871)	(417,696)	(303,274)	(303,275)
Beginning True-up Amount		(1,482,331)	(4,011,711)	(2,342,163)	(4,378,759)	(3,483,971)	(4,445,969)	(2,933,955)	(2,344,726)	(1,597,632)	(595,031)	(159,871)	(417,696)	
Ending True-up Amount Before Interest		(4,006,085)	(2,335,762)	(4,371,974)	(3,476,034)	(4,437,980)	(2,926,737)	(2,339,791)	(1,594,160)	(593,205)	(159,299)	(417,303)	(302,794)	
Total Beginning and Ending True-up		(5,488,416)	(6,347,473)	(6,714,137)	(7,854,793)	(7,921,950)	(7,372,705)	(5,273,746)	(3,938,886)	(2,190,837)	(754,331)	(577,175)	(720,491)	
Average True-up Amount		(2,744,208)	(3,173,737)	(3,357,069)	(3,927,396)	(3,960,975)	(3,686,353)	(2,636,873)	(1,969,443)	(1,095,418)	(377,165)	(288,587)	(360,245)	
Average Annual Interest Rate		2.4600%	2.4200%	2.4250%	2.4250%	2.4200%	2.3500%	2.2450%	2.1150%	2.0000%	1.8200%	1.6350%	1.6000%	
Interest Provision		(5,626)	(6,401)	(6,785)	(7,937)	(7,989)	(7,218)	(4,934)	(3,472)	(1,826)	(572)	(393)	(480)	

10% Rule Interest Provision. -0.53%

2152

FLORIDA PUBLIC UTILITIES COMPANY
CALCULATION OF TRUE-UP SURCHARGE
APPLICABLE TO LEVELIZED FUEL ADJUSTMENT PERIOD
JANUARY 2020 - DECEMBER 2020
BASED ON SIX MONTHS ACTUAL AND SIX MONTHS ESTIMATED OPERATIONS

Revised 10_22_2020

Florida Division -CONSOLIDATED

Over-recovery of purchased power costs for the period January 2020 - December 2020. (See Schedule E1-B, Calculation of Estimated Purchased Power Costs and Calculation of True-Up and Interest Provision for the Twelve Month Period ended December 2020.)(Estimated)	$	(297,168)

Exhibit No.________________
DOCKET NO. 20200001-EI
Florida Public Utilities Company
(Revised CDY-2)
Page 1 of 3

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20200001-EI EXHIBIT: 28
PARTY: FLORIDA PUBLIC UTILITIES COMPANY – DIRECT
DESCRIPTION: Curtis D. Young CDY-2

FLORIDA PUBLIC UTILITIES COMPANY

Schedule E-1b

CALCULATION OF PURCHASED POWER COSTS AND CALCULATION OF TRUE-UP AND INTEREST PROVISION-EXCLUDING GSLD1

ACTUAL/ESTIMATED FOR THE PERIOD: JANUARY 2020 THROUGH DECEMBER 2020

BASED ON SIX MONTHS ACTUAL AND SIX MONTHS ESTIMATED

(EXCLUDES LINE LOSS, EXCLUDES TAXES)

CONSOLIDATED

Revised 10_22_2020

		ACTUAL Jan 2020	ACTUAL Feb 2020	ACTUAL Mar 2020	ACTUAL Apr 2020	ACTUAL May 2020	ACTUAL Jun 2020	Estimated Jul 2020	Estimated Aug 2020	Estimated Sep 2020	Estimated Oct 2020	Estimated Nov 2020	Estimated Dec 2020	Total
Total System Sales - KWH		46,124,472	43,763,223	40,566,336	42,455,602	43,068,192	51,431,735	57,013,028	56,620,476	56,396,478	55,663,197	47,633,732	45,974,398	586,710,869
West-Rock Purchases - KWH		1,020,000	1,150,000	390,000	240,000	360,000	420,000	700,000	400,000	700,000	900,000	500,000	700,000	7,480,000
Rayonier Purchases - KWH - On Peak		40,088	68,692	96,733	55,617	2,478	22,915	310,500	310,500	310,500	310,500	310,500	310,500	2,149,523
Rayonier Purchases - KWH - Off Peak		244,082	162,561	140,260	139,799	144,161	127,811	589,500	589,500	589,500	589,500	589,500	589,500	4,495,674
Eight Flags Purchases - KWH - KWH		15,182,978	13,530,427	15,396,795	14,740,660	14,548,725	12,919,968	12,500,000	12,800,000	12,400,000	15,500,000	15,200,000	15,800,000	170,519,553
FPL Purchases - KWH		11,656,613	8,816,904	5,270,960	7,497,233	14,634,407	20,624,092	21,118,482	20,717,305	20,593,111	15,627,836	10,457,307	9,265,073	166,279,323
Gulf Purchases - KWH		23,471,161	21,007,047	21,513,838	19,820,726	23,913,356	28,150,827	24,645,198	24,634,194	24,623,191	25,518,521	22,958,112	21,608,045	281,864,216
Generation Demand - KW - FPL		59,604	52,531	33,091	51,849	54,052	89,465	66,735	70,199	57,463	50,433	48,192	47,580	681,193
Generation Demand - KW - Gulf		64,609	55,246	45,611	48,506	51,498	61,590	65,000	64,400	61,400	58,500	49,200	59,500	685,060
Transmission Demand - KW - FPL		59,978	63,067	42,962	48,146	49,997	92,146	55,000	58,400	45,900	39,000	36,800	36,200	627,596
Transmission Demand - KW - Southern		55,955	56,072	56,297	57,002	56,000	56,090	55,000	55,000	55,000	55,000	55,000	55,000	667,416
Purchased Power Rates:														
West Rock Fuel Costs - $/KWH		0.03224	0.02446	(0.00053)	0.01354	0.02761	0.02587	0.03648	0.03648	0.03648	0.03648	0.03648	0.03648	
Rayonier Energy Charge - On Peak - $/KWH		0.03491	0.03491	0.03491	0.02368	0.02754	0.02754	0.04826	0.04826	0.04826	0.04826	0.04826	0.04826	
Rayonier Energy Charge - Off Peak - $/KWH		0.03248	0.03248	0.03248	0.02078	0.02383	0.02383	0.03898	0.03898	0.03898	0.03898	0.03898	0.03898	
Eight Flags Charge - $/KWH		0.07438	0.07095	0.06959	0.06780	0.06886	0.07147	0.08473	0.08473	0.08473	0.08473	0.08473	0.08473	
Base Fuel Costs - $/KWH - FPL		0.02629	0.01918	0.01005	0.01517	0.02774	0.02624	0.03037	0.03026	0.03060	0.03095	0.02947	0.02481	
Base Fuel Costs - $/KWH GULF	0.974	0.01946	0.01814	0.01701	0.01649	0.01763	0.01800	0.02517	0.02517	0.02586	0.02909	0.02941	0.02538	
Energy Charge - $/KWH - FPL		0.00661	0.00794	0.01248	0.00869	0.00549	0.00465	0.00453	0.00459	0.00449	0.00491	0.00608	0.00776	
Demand and Non-Fuel:														
Demand Charge - $/KW - FPL		6.53	6.70	7.56	6.72	6.66	6.10	6.39	6.34	6.58	6.76	6.83	6.85	
Demand Charge - $/KW - Gulf		7.86	8.31	8.95	8.73	8.53	5.05	7.85	7.87	8.00	8.14	8.68	8.09	
Distribution Facility Charge		1.55234	1.54954	1.54117	1.52155	1.54639	1.54969	2.60415	2.60415	2.60415	2.60415	2.60415	2.60415	
Transmission Charge $/KW - FPL		3.13960	3.61204	4.91039	3.15276	3.49933	3.16289	2.43455	2.43454	2.43453	2.43454	2.43454	2.43453	
Transmission Charge $/KW - Southern		3.01632	3.01632	3.01631	3.01635	3.06438	3.31430	2.17647	2.13805	1.94602	1.76038	1.15505	1.82440	
Purchased Power Costs:														
West-Rock Fuel Costs		32,882	28,131	(207)	3,249	9,940	10,867	25,536	14,592	25,536	32,832	18,240	25,536	227,134
Rayonier Standby Costs		9,327	7,678	7,932	4,223	3,504	3,677	37,964	37,964	37,964	37,964	37,964	37,964	264,125
Eight Flags		1,129,372	959,932	1,071,505	999,485	1,001,850	923,410	1,059,125	1,084,544	1,050,652	1,313,315	1,287,896	1,338,734	13,219,820
Gulf Base Fuel Costs		456,822	380,975	365,867	326,777	421,601	506,835	620,408	620,010	636,813	742,325	675,284	548,436	6,302,153
FPL Base Fuel Costs		306,404	169,105	52,963	113,741	405,894	541,116	641,456	626,946	630,222	483,658	308,190	229,836	4,509,531
FPL Fuel Adjustment		77,060	70,011	65,787	65,124	80,301	95,976	95,605	95,102	92,419	76,742	63,549	71,858	949,534
Subtotal Fuel Costs		2,011,867	1,615,832	1,563,847	1,512,599	1,923,090	2,081,881	2,480,094	2,479,158	2,473,606	2,686,836	2,391,123	2,252,364	25,472,296
Demand and Non-Fuel Costs:	Demand Capacity Charge	897,368	811,080	658,436	772,114	799,388	856,900	936,857	951,893	869,281	817,148	756,556	807,421	9,934,442
	Distr. Fac. Charge	86,861	86,886	86,763	86,731	86,598	86,922	143,228	143,228	143,228	143,228	143,228	143,228	1,380,129
	Customer Charges	4,000	4,000	4,000	4,000	4,000	4,000	4,000	4,000	4,000	4,000	4,000	4,000	48,000
	Transmission Charge	357,085	396,932	380,769	323,731	346,561	477,347	253,606	259,770	218,776	191,768	153,669	188,472	3,548,485
Subtotal Demand & Non-Fuel Costs		1,345,314	1,298,898	1,129,968	1,186,576	1,236,547	1,425,169	1,337,691	1,358,891	1,235,285	1,156,144	1,057,453	1,143,121	14,911,056
Total System Purchased Power Costs		3,357,181	2,914,730	2,693,815	2,699,175	3,159,636	3,507,050	3,817,785	3,838,049	3,708,891	3,842,980	3,448,576	3,395,485	40,383,352
Less Direct Billing To GSLD1 Class:	Demand	105,944	81,729	(289,768)	17,029	28,724	(12,805)	30,407	30,407	30,407	30,407	30,407	30,407	113,294
	Commodity	(1,090)	3,471	10,762	3,175	12,695	23,426	68,200	51,186	50,976	55,101	60,536	77,043	415,481
Net Purchased Power Costs		3,252,327	2,829,530	2,972,821	2,678,970	3,118,217	3,496,429	3,719,178	3,756,456	3,627,508	3,757,472	3,357,633	3,288,035	39,854,577
		0	0	0	0	0	0	0	0	0	0	0	0	0
	Special Costs*	1,960	25,242	995	6,460	14,922	12,649	8,925	8,925	9,650	8,925	8,925	10,150	117,726
Total Costs and Charges		3,254,287	2,854,772	2,973,816	2,685,430	3,133,139	3,509,078	3,728,103	3,765,381	3,637,158	3,766,397	3,366,558	3,298,185	39,972,304
Sales Revenues - Fuel Adjustment Revenues:														
RS<	0.07454	1,300,141	1,292,120	1,223,294	1,224,127	1,244,061	1,400,952	1,386,978	1,388,170	1,388,692	1,400,137	1,224,059	1,271,922	15,744,653
RS>	0.08703	472,335	429,438	295,532	380,380	414,284	673,318	707,740	704,211	650,767	598,381	320,107	380,711	6,027,204
GS	0.07530	302,113	302,592	273,990	285,837	277,295	340,292	387,389	387,642	388,148	373,989	314,547	288,516	3,922,350
GSD	0.07223	860,359	817,751	792,294	807,527	799,455	953,693	1,129,333	1,151,622	1,142,375	1,104,500	1,067,138	899,163	11,525,210
GSLD	0.07004	429,065	381,274	381,145	405,635	428,719	432,819	530,930	506,688	541,795	575,011	491,924	451,451	5,556,456
LS	0.05617	35,167	35,082	34,985	34,829	34,794	34,789	35,583	35,369	35,546	34,606	34,781	34,855	420,386
Unbilled Fuel Revenues		(531,323)	206,031	(44,628)	(31,070)	23,255	361,616	0	0	0	0	0	0	(16,119)
Total Fuel Revenues (Excl. GSLD1)		2,867,857	3,464,288	2,956,612	3,107,265	3,221,863	4,197,479	4,177,953	4,173,702	4,147,323	4,086,624	3,452,556	3,326,618	43,180,139
GSLD1 Fuel Revenues	.17197	104,854	85,200	(279,006)	20,204	41,419	10,621	98,607	81,593	81,383	85,508	90,943	107,450	528,775
Non-Fuel Revenues		2,283,185	2,175,757	1,687,923	2,020,524	2,125,910	2,429,393	2,992,982	2,811,401	2,798,088	1,834,509	1,861,988	2,593,999	27,615,661
Total Sales Revenue		5,255,896	5,725,245	4,365,529	5,147,993	5,389,192	6,637,492	7,269,543	7,066,696	7,026,794	6,006,642	5,405,487	6,028,067	71,324,575
KWH Sales:	RS<	17,440,088	17,336,516	16,415,648	16,423,857	16,691,757	18,797,031	18,607,171	18,623,150	18,630,156	18,783,698	16,421,502	17,063,615	211,234,188
	RS>	5,426,957	4,934,587	3,393,219	4,370,806	4,760,390	7,736,857	8,132,138	8,091,588	7,477,501	6,875,568	3,678,128	4,374,478	69,252,218
	GS	4,016,057	4,018,710	3,638,850	3,796,191	3,682,743	4,519,400	5,144,612	5,147,972	5,154,691	4,966,650	4,177,253	3,831,552	52,094,681
	GSD	11,911,722	11,321,800	10,969,350	11,180,245	11,068,489	13,203,918	15,635,233	15,943,819	15,815,799	15,291,426	14,774,164	12,448,607	159,564,573
	GSLD	6,128,433	5,443,691	5,441,849	5,791,512	6,121,096	6,179,635	7,580,380	7,234,267	7,735,507	8,209,757	7,023,473	6,445,616	79,335,216
	GSLD1	574,000	82,000	82,000	272,000	124,000	374,000	1,280,000	950,000	950,000	920,000	940,000	1,190,000	7,738,000
	LS	627,215	625,919	625,420	620,991	619,717	620,894	633,494	629,680	632,823	616,097	619,212	620,531	7,491,993
	Total KWH Sales	46,124,472	43,763,223	40,566,336	42,455,602	43,068,192	51,431,735	57,013,028	56,620,476	56,396,478	55,663,197	47,633,732	45,974,398	586,710,869
True-up Calculation (Excl. GSLD1):														
Fuel Revenues		2,867,857	3,464,288	2,956,612	3,107,265	3,221,863	4,197,479	4,177,953	4,173,702	4,147,323	4,086,624	3,452,556	3,326,618	43,180,139
True-up Provision - collect/(refund)		161,204	161,204	161,204	161,204	161,204	161,204	161,204	161,204	161,204	161,204	161,204	161,204	1,934,452
Gross Receipts Tax Refund														0
Fuel Revenue		2,706,653	3,303,084	2,795,408	2,946,061	3,060,658	4,036,274	4,016,749	4,012,498	3,986,119	3,925,420	3,291,352	3,165,414	41,245,688
Net Purchased Power and Other Fuel Costs		3,254,287	2,854,772	2,973,816	2,685,430	3,133,139	3,509,078	3,728,103	3,765,381	3,637,158	3,766,397	3,366,558	3,298,185	39,972,304
True-up Provision for the Period		(547,634)	448,311	(178,408)	260,631	(72,480)	527,196	288,646	247,117	348,960	159,023	(75,206)	(132,772)	1,273,384
Interest Provision for the Period		(5,493)	(5,219)	(5,342)	(3,154)	(450)	(253)	(203)	(165)	(125)	2	20	25	(20,357)
Beginning of Period True-up and Interest Provision		(3,952,348)	(4,344,271)	(3,739,974)	(3,762,520)	(3,308,014)	(3,219,739)	(2,531,592)	(2,081,945)	(1,673,789)	(137,537)	182,692	268,710	(3,952,348)
True-up Collected or (Refunded)		161,204	161,204	161,204	161,204	161,204	161,204	161,204	161,204	161,204	161,204	161,204	161,204	1,934,452
Overcollected Interin Rates-Hurricane Michael					35,825					1,026,212				1,062,037
End of Period, Net True-up and Int. Prov.		(4,344,271)	(3,739,974)	(3,762,520)	(3,308,014)	(3,219,739)	(2,531,592)	(2,081,945)	(1,673,789)	(137,537)	182,692	268,710	297,168	297,168
Beginning True-up Amount		(3,952,348)	(4,344,271)	(3,739,974)	(3,762,520)	(3,308,014)	(3,219,739)	(2,531,592)	(2,081,945)	(1,673,789)	(137,537)	182,692	268,710	
Ending True-up Amount Before Interest		(4,338,778)	(3,734,755)	(3,757,178)	(3,340,685)	(3,219,289)	(2,531,339)	(2,081,742)	(1,673,624)	(1,163,624)	182,690	268,690	297,143	10% Rule Interest Provision: 0.74%
Total Beginning and Ending True-up		(8,291,126)	(8,079,026)	(7,497,152)	(7,103,204)	(6,527,303)	(5,751,079)	(4,613,334)	(3,755,569)	(2,837,413)	45,153	451,383	565,853	
Average True-up Amount		(4,145,563)	(4,039,513)	(3,748,576)	(3,551,602)	(3,263,651)	(2,875,539)	(2,306,667)	(1,877,784)	(1,418,707)	22,577	225,691	282,927	
Average Annual Interest Rate		1.5900%	1.5500%	1.7100%	1.0650%	0.1650%	0.1050%	0.1050%	0.1050%	0.1050%	0.1050%	0.1050%	0.1050%	
Interest Provision		(5,493)	(5,219)	(5,342)	(3,154)	(450)	(253)	(203)	(165)	(125)	2	20	25	

* Includes: Consulting fees, Legal fees and Taxes on Company Use.

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Florida Public Utilities Compar
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SCHEDULE E1-B1

FLORIDA PUBLIC UTILITIES COMPANY
CONSOLIDATED FLORIDA DIVISIONS
COMPARISON OF ESTIMATED/ACTUAL VERSUS ORIGINAL PROJECTIONS
OF THE FUEL AND PURCHASED POWER COST RECOVERY FACTOR
JANUARY 2020 - DECEMBER 2020

Revised 10_22_2020

	DOLLARS				MWH				CENTS/KWH			
	ESTIMATED/ ACTUAL	ESTIMATED/ ORIGINAL	DIFFERENCE AMOUNT	%	ESTIMATED/ ACTUAL	ESTIMATED/ ORIGINAL	DIFFERENCE AMOUNT	%	ESTIMATED/ ACTUAL	ESTIMATED/ ORIGINAL	DIFFERENCE AMOUNT	%
1 Fuel Cost of System Net Generation (A3)					0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
2 Nuclear Fuel Disposal Cost (A13)												
3 Coal Car Investment												
4 Adjustments to Fuel Cost (A2, Page 1)												
5 TOTAL COST OF GENERATED POWER	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
6 Fuel Cost of Purchased Power (Exclusive of Economy) (A8)	11,761,218	12,007,308	(246,091)	-2.1%	448,143	429,024	19,119	4.5%	2.62443	2.79875	(0.17432)	-6.2%
7 Energy Cost of Sched C & X Econ Purch (Broker)(A9)												
8 Energy Cost of Other Econ Purch (Non-Broker)(A9)												
9 Energy Cost of Sched E Economy Purch (A9)												
10 Demand and Non Fuel Cost of Purchased Power (A9)	14,911,056	15,020,005	(108,949)	-0.7%	448,143	429,024	19,119	4.5%	3.32730	3.50097	(0.17367)	-5.0%
11 Energy Payments to Qualifying Facilities (A8a)	13,711,079	15,601,107	(1,890,028)	-12.1%	184,646	193,850	(9,204)	-4.8%	7.42560	8.04803	(0.62243)	-7.7%
12 TOTAL COST OF PURCHASED POWER	40,383,352	42,628,420	(2,245,068)	-5.3%	632,789	622,874	9,915	1.6%	6.38180	6.84383	(0.46203)	-6.8%
13 TOTAL AVAILABLE MWH (LINE 5 + LINE 12)					632,789	622,874	9,915	1.6%				
14 Fuel Cost of Economy Sales (A7)												
15 Gain on Economy Sales (A7a)												
16 Fuel Cost of Unit Power Sales (SL2 Partpts)(A7)												
17 Fuel Cost of Other Power Sales (A7)	117,726	221,000	(103,274)	-46.7%								
18 TOTAL FUEL COST AND GAINS OF POWER SALES (LINE 14 + 15 + 16 + 17)	117,726	221,000	(103,274)	-46.7%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
19 NET INADVERTENT INTERCHANGE (A10)												
20 TOTAL FUEL AND NET POWER TRANSACTIONS (LINES 5 + 12 + 18 + 19)	40,501,079	42,849,420	(2,348,341)	-5.5%	632,789	622,874	9,915	1.6%	6.40041	6.87931	(0.47890)	-7.0%
21 Net Unbilled Sales (A4)	0 *	0 *	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
22 Company Use (A4)	31,426 *	31,714 *	(288)	-0.9%	491	461	30	6.5%	0.00536	0.00530	0.00006	1.1%
23 T & D Losses (A4)	2,917,755 *	1,629,502 *	1,288,253	79.1%	45,587	23,687	21,900	92.5%	0.49731	0.27216	0.22515	82.7%
24 SYSTEM KWH SALES	40,501,079	42,849,420	(2,348,341)	-5.5%	586,711	598,726	(12,015)	-2.0%	6.90308	7.15677	(0.25369)	-3.5%
25 Wholesale KWH Sales												
26 Jurisdictional KWH Sales	40,501,079	42,849,420	(2,348,341)	-5.5%	586,711	598,726	(12,015)	-2.0%	6.90308	7.15677	(0.25369)	-3.5%
26a Jurisdictional Loss Multiplier	1.000	1.000	0.000	0.0%	1.000	1.000	0.000	0.0%	1.000	1.000	0.00000	0.0%
27 Jurisdictional KWH Sales Adjusted for Line Losses	40,501,079	42,849,420	(2,348,341)	-5.5%	586,711	598,726	(12,015)	-2.0%	6.90308	7.15677	(0.25369)	-3.5%
28 GPIF**												
29 TRUE-UP**	1,934,452	1,934,452	0	0.0%	586,711	598,726	(12,015)	-2.0%	0.32971	0.32309	0.00662	2.1%
30 TOTAL JURISDICTIONAL FUEL COST	42,435,531	44,783,872	(2,348,341)	-5.2%	586,711	598,726	(12,015)	-2.0%	7.23278	7.47986	(0.24708)	-3.3%
31 Revenue Tax Factor									1.00072	1.00072	0.00000	0.0%
32 Fuel Factor Adjusted for Taxes									7.23799	7.48525	(0.24726)	-3.3%
33 FUEL FAC ROUNDED TO NEAREST .001 (CENTS/KWH)									7.238	7.485	(0.247)	-3.3%

*Included for Informational Purposes Only
**Calculation Based on Jurisdictional KWH Sales

EXHIBIT NO. ________
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FLORIDA PUBLIC UTILITIES COMPANY
(Revised CDY-2)
PAGE 3 OF 3

Company: FLORIDA PUBLIC UTILITIES COMPANY
CONSOLIDATED ELECTRIC DIVISIONS

COMPARISON OF ESTIMATED AND ACTUAL
FUEL AND PURCHASED POWER COST RECOVERY FACTOR
MONTH: JANUARY 2020 REVISED 7_27_2020

SCHEDULE A1
PAGE 1 OF 2

		DOLLARS				MWH				CENTS/KWH			
		ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%
1	Fuel Cost of System Net Generation (A3)					0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
2	Nuclear Fuel Disposal Cost (A13)												
3	FPL Interconnect	0	0	0	0.0%								
4	Adjustments to Fuel Cost (A2, Page 1)			0	0.0%								
5	TOTAL COST OF GENERATED POWER	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
6	Fuel Cost of Purchased Power (Exclusive of Economy) (A8)	763,225	678,819	84,406	12.4%	35,128	27,981	7,147	25.5%	2.17270	2.42604	(0.25334)	-10.4%
7	Energy Cost of Sched C & X Econ Purch (Broker)(A9)												
8	Energy Cost of Other Econ Purch (Non-Broker)(A9)												
9	Energy Cost of Sched E Economy Purch (A9)												
10	Demand and Non Fuel Cost of Purchased Power (A9)	1,422,373	1,485,147	(62,774)	-4.2%	35,128	27,981	7,147	25.5%	4.04911	5.30779	(1.25868)	-23.7%
11	Energy Payments to Qualifying Facilities (A8a)	1,171,582	1,392,584	(221,002)	-15.9%	16,487	17,400	(913)	-5.3%	7.10603	8.00336	(0.89733)	-11.2%
12	TOTAL COST OF PURCHASED POWER	3,357,180	3,556,550	(199,369)	-5.6%	51,615	45,381	6,235	13.7%	6.50425	7.83717	(1.33292)	-17.0%
13	TOTAL AVAILABLE MWH (LINE 5 + LINE 12)					51,615	45,381	6,235	13.7%				
14	Fuel Cost of Economy Sales (A7)												
15	Gain on Economy Sales (A7a)												
16	Fuel Cost of Unit Power Sales (SL2 Partpts)(A7)												
17	Fuel Cost of Other Power Sales (A7)												
18	TOTAL FUEL COST AND GAINS OF POWER SALES (LINE 14 + 15 + 16 + 17)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
19	NET INADVERTENT INTERCHANGE (A10)												
20	LESS GSLD APPORTIONMENT OF FUEL COST	104,854	121,924	(17,070)	-13.3%	0	0	0	0.0%				
20a	TOTAL FUEL AND NET POWER TRANSACTIONS (LINES 5 + 12 + 18 + 19)	3,252,326	3,434,626	(182,299)	-5.3%	51,615	45,381	6,235	13.7%	6.30111	7.56850	(1.26739)	-16.8%
21	Net Unbilled Sales (A4)	148,778 *	(44,933) *	193,711	-431.1%	2,361	(594)	2,955	-497.7%	0.32256	(0.10396)	0.42652	-410.3%
22	Company Use (A4)	2,080 *	2,361 *	(281)	-11.9%	33	31	2	5.8%	0.00451	0.00546	(0.00095)	-17.4%
23	T & D Losses (A4)	195,145 *	206,090 *	(10,945)	-5.3%	3,097	2,723	374	13.7%	0.42309	0.47684	(0.05375)	-11 3%
24	SYSTEM KWH SALES	3,252,326	3,434,626	(182,299)	-5.3%	46,124	43,220	2,904	6.7%	7.05127	7.94684	(0.89557)	-11.3%
25	Wholesale KWH Sales												
26	Jurisdictional KWH Sales	3,252,326	3,434,626	(182,299)	-5.3%	46,124	43,220	2,904	6.7%	7.05127	7.94684	(0.89557)	-11.3%
26a	Jurisdictional Loss Multiplier	1.000	1.000	0.000	0.0%	1.000	1.000	0.000	0.0%	1.000	1.000	0.00000	0.0%
27	Jurisdictional KWH Sales Adjusted for Line Losses	3,252,326	3,434,626	(182,300)	-5.3%	46,124	43,220	2,904	6.7%	7.05127	7.94684	(0.89557)	-11.3%
28	GPIF**												
29	TRUE-UP**	161,204	161,204	0	0.0%	46,124	43,220	2,904	6.7%	0.34950	0.37298	(0.02348)	-6.3%
30	TOTAL JURISDICTIONAL FUEL COST (Excluding GSLD Apportionment)	3,413,530	3,595,830	(182,300)	-5.1%	46,124	43,220	2,904	6.7%	7.40077	8.31983	(0.91906)	-11.1%
31	Revenue Tax Factor									1.01609	1.01609	0.00000	0.0%
32	Fuel Factor Adjusted for Taxes									7.51985	8.45370	(0.93385)	-11.1%
33	FUEL FAC ROUNDED TO NEAREST .001 (CENTS/KWH)									7.520	8.454	(0.934)	-11.1%

*Included for Informational Purposes Only
**Calculation Based on Jurisdictional KWH Sales

Exhibit No.__________
DOCKET NO. 20200001-EI
Florida Public Utilities Company
(CDY-3)
Page 1 of 60

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20200001-EI EXHIBIT: 29
PARTY: FLORIDA PUBLIC UTILITIES COMPANY – DIRECT
DESCRIPTION: Curtis D. Young CDY-3

Company: FLORIDA PUBLIC UTILITIES COMPANY

CONSOLIDATED ELECTRIC DIVISIONS

COMPARISON OF ESTIMATED AND ACTUAL
FUEL AND PURCHASED POWER COST RECOVERY FACTOR
MONTH: JANUARY 2020 REVISED 7_27_2020

		PERIOD TO DATE DOLLARS				PERIOD TO DATE MWH				CENTS/KWH			
		ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%
1	Fuel Cost of System Net Generation (A3)					0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
2	Nuclear Fuel Disposal Cost (A13)												
3	FPL Interconnect	0	0	0	0.0%								
4	Adjustments to Fuel Cost (A2, Page 1)	0	0	0	0.0%								
5	TOTAL COST OF GENERATED POWER	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
6	Fuel Cost of Purchased Power (Exclusive of Economy) (A8)	763,225	678,819	84,406	12.4%	35,128	27,981	7,147	25.5%	2.17270	2.42604	(0.25334)	-10.4%
7	Energy Cost of Sched C & X Econ Purch (Broker)(A9)												
8	Energy Cost of Other Econ Purch (Non-Broker)(A9)												
9	Energy Cost of Sched E Economy Purch (A9)												
10	Demand and Non Fuel Cost of Purchased Power (A9)	1,422,373	1,485,147	(62,774)	-4.2%	35,128	27,981	7,147	25.5%	4.04911	5.30779	(1.25868)	-23.7%
11	Energy Payments to Qualifying Facilities (A8a)	1,171,582	1,392,584	(221,002)	-15.9%	16,487	17,400	(913)	-5.3%	7.10603	8.00336	(0.89733)	-11.2%
12	TOTAL COST OF PURCHASED POWER	3,357,180	3,556,550	(199,369)	-5.6%	51,615	45,381	6,235	13.7%	6.50425	7.83717	(1.33292)	-17.0%
13	TOTAL AVAILABLE MWH (LINE 5 + LINE 12)					51,615	45,381	6,235	13.7%				
14	Fuel Cost of Economy Sales (A7)												
15	Gain on Economy Sales (A7a)												
16	Fuel Cost of Unit Power Sales (SL2 Partpts)(A7)												
17	Fuel Cost of Other Power Sales (A7)												
18	TOTAL FUEL COST AND GAINS OF POWER SALES (LINE 14 + 15 + 16 + 17)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
19	NET INADVERTENT INTERCHANGE (A10)												
20	LESS GSLD APPORTIONMENT OF FUEL COST	104,854	121,924	(17,070)	-14.0%	0	0	0	0.0%				
20a	TOTAL FUEL AND NET POWER TRANSACTIONS (LINES 5 + 12 + 18 + 19)	3,252,326	3,434,625	(182,299)	-5.3%	51,615	45,381	6,235	13.7%	6.30111	7.56850	(1.26739)	-16.8%
21	Net Unbilled Sales (A4)	148,778 *	(44,933) *	193,711	-431.1%	2,361	(594)	2,955	-497.7%	0.32256	(0.10396)	0.42652	-410.3%
22	Company Use (A4)	2,080 *	2,361 *	(281)	-11.9%	33	31	2	5.8%	0.00451	0.00546	(0.00095)	-17.4%
23	T & D Losses (A4)	195,145 *	206,090 *	(10,945)	-5.3%	3,097	2,723	374	13.7%	0.42309	0.47684	(0.05375)	-11.3%
24	SYSTEM KWH SALES	3,252,326	3,434,625	(182,299)	-5.3%	46,124	43,220	2,904	6.7%	7.05127	7.94684	(0.89557)	-11.3%
25	Wholesale KWH Sales												
26	Jurisdictional KWH Sales	3,252,326	3,434,625	(182,299)	-5.3%	46,124	43,220	2,904	6.7%	7.05127	7.94684	(0.89557)	-11.3%
26a	Jurisdictional Loss Multiplier	1.000	1.000	0.000	0.0%	1.000	1.000	0.000	0.0%	1.000	1.000	0.00000	0.0%
27	Jurisdictional KWH Sales Adjusted for Line Losses	3,252,326	3,434,625	(182,299)	-5.3%	46,124	43,220	2,904	6.7%	7.05127	7.94684	(0.89557)	-11.3%
28	GPIF**												
29	TRUE-UP**	161,204	161,204	(0)	0.0%	46,124	43,220	2,904	6.7%	0.34950	0.37299	(0.02349)	-6.3%
30	TOTAL JURISDICTIONAL FUEL COST	3,413,530	3,595,829	(182,299)	-5.1%	46,124	43,220	2,904	6.7%	7.40077	8.31983	(0.91906)	-11.1%
31	Revenue Tax Factor									1.01609	1.01609	0.00000	0.0%
32	Fuel Factor Adjusted for Taxes									7.51985	8.45370	(0.93385)	-11.1%
33	FUEL FAC ROUNDED TO NEAREST .001 (CENTS/KWH)									7.520	8.454	(0.934)	-11.1%

*Included for Informational Purposes Only
**Calculation Based on Jurisdictional KWH Sales

Exhibit No.________________
DOCKET NO. 20200001-EI
Florida Public Utilities Company
(CDY-3)
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CALCULATION OF TRUE-UP AND INTEREST PROVISION

Company: FLORIDA PUBLIC UTILITIES COMPANY

Division: CONSOLIDATED ELECTRIC DIVISIONS

Month of: JANUARY 2020 REVISED 7_27_2020

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%
A. Fuel Cost & Net Power Transactions								
1. Fuel Cost of System Net Generation	$ 0	$ 0	$ 0	0.0%	$ 0	$ 0	$ 0	0.0%
1a. Fuel Related Transactions (Nuclear Fuel Disposal)								
2. Fuel Cost of Power Sold								
3. Fuel Cost of Purchased Power	763,225	678,819	84,406	12.4%	763,225	678,819	84,406	12.4%
3a. Demand & Non Fuel Cost of Purchased Power	1,422,373	1,485,147	(62,774)	-4.2%	1,422,373	1,485,147	(62,774)	-4.2%
3b. Energy Payments to Qualifying Facilities	1,171,582	1,392,584	(221,002)	-15.9%	1,171,582	1,392,584	(221,002)	-15.9%
4. Energy Cost of Economy Purchases								
5. Total Fuel & Net Power Transactions	3,357,180	3,556,550	(199,369)	-5.6%	3,357,180	3,556,550	(199,369)	-5.6%
6. Adjustments to Fuel Cost (Describe Items)								
6a. Special Meetings - Fuel Market Issue	1,960	17,850	(15,890)	-89.0%	1,960	17,850	(15,890)	-89.0%
7. Adjusted Total Fuel & Net Power Transactions	3,359,141	3,574,400	(215,259)	-6.0%	3,359,141	3,574,400	(215,259)	-6.0%
8. Less Apportionment To GSLD Customers	104,854	121,924	(17,070)	-14.0%	104,854	121,924	(17,070)	-14.0%
9. Net Total Fuel & Power Transactions To Other Classes	$ 3,254,287	$ 3,452,476	$ (198,189)	-5.7%	$ 3,254,287	$ 3,452,476	$ (198,189)	-5.7%

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CALCULATION OF TRUE-UP AND INTEREST PROVISION

Company: FLORIDA PUBLIC UTILITIES COMPANY

Division: CONSOLIDATED ELECTRIC DIVISIONS

Month of: JANUARY 2020 REVISED 7_27_2020

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%
B. Sales Revenues (Exclude Revenue Taxes & Franchise Taxes)								
1. Jurisidictional Sales Revenue (Excluding GSLD)	$	$	$		$	$	$	
a. Base Fuel Revenue								
b. Fuel Recovery Revenue	2,867,857	3,220,128	(352,271)	-10.9%	2,867,857	3,220,128	(352,271)	-10.9%
c. Jurisidictional Fuel Revenue	2,867,857	3,220,128	(352,271)	-10.9%	2,867,857	3,220,128	(352,271)	-10.9%
d. Non Fuel Revenue	2,250,587	2,231,577	19,010	0.9%	2,250,587	2,231,577	19,010	0.9%
e. Total Jurisdictional Sales Revenue	5,118,444	5,451,705	(333,261)	-6.1%	5,118,444	5,451,705	(333,261)	-6.1%
2. Non Jurisdictional Sales Revenue	0	0	0	0.0%	0	0	0	0.0%
3. Total Sales Revenue (Excluding GSLD)	$ 5,118,444	$ 5,451,705	$ (333,261)	-6.1%	$ 5,118,444	$ 5,451,705	$ (333,261)	-6.1%
C. KWH Sales (Excluding GSLD)								
1. Jurisdictional Sales KWH	45,550,472	41,849,543	3,700,929	8.8%	45,550,472	41,849,543	3,700,929	8.8%
2. Non Jurisdictional Sales	0	0	0	0.0%	0	0	0	0.0%
3. Total Sales	45,550,472	41,849,543	3,700,929	8.8%	45,550,472	41,849,543	3,700,929	8.8%
4. Jurisdictional Sales % of Total KWH Sales	100.00%	100.00%	0.00%	0.0%	100.00%	100.00%	0.00%	0.0%

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Company: FLORIDA PUBLIC UTILITIES COMPANY

Division: CONSOLIDATED ELECTRIC DIVISIONS

Month of: JANUARY 2020 REVISED 7_27_2020

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%
D. True-up Calculation (Excluding GSLD)								
1. Jurisdictional Fuel Rev. (line B-1c)	$ 2,867,857	$ 3,220,128	$ (352,271)	-10.9%	$ 2,867,857	$ 3,220,128	$ (352,271)	-10.9%
2. Fuel Adjustment Not Applicable								
a. True-up Provision	161,204	161,204	(0)	0.0%	161,204	161,204	(0)	0.0%
b. Incentive Provision								
c. Transition Adjustment (Regulatory Tax Refund)							0	0.0%
3. Jurisdictional Fuel Revenue Applicable to Period	2,706,653	3,058,924	(352,271)	-11.5%	2,706,653	3,058,924	(352,271)	-11.5%
4. Adjusted Total Fuel & Net Power Transaction (Line A-7)	3,254,287	3,452,476	(198,189)	-5.7%	3,254,287	3,452,476	(198,189)	-5.7%
5. Jurisdictional Sales % of Total KWH Sales (Line C-4)	100%	100%	0.00%	0.0%	N/A	N/A		
6. Jurisdictional Total Fuel & Net Power Transactions (Line D-4 x Line D-5 x *)	3,254,287	3,452,476	(198,189)	-5.7%	3,254,287	3,452,476	(198,189)	-5.7%
7. True-up Provision for the Month Over/Under Collection (Line D-3 - Line D-6)	(547,634)	(393,552)	(154,082)	39.2%	(547,634)	(393,552)	(154,082)	39.2%
8. Interest Provision for the Month	(5,493)	(2,541)	(2,952)	116.2%	(5,493)	(2,541)	(2,952)	116.2%
9. True-up & Inst. Provision Beg. of Month	(3,952,348)	666,626	(4,618,974)	-692.9%	(3,952,348)	666,626	(4,618,974)	-692.9%
9a. Deferred True-up Beginning of Period								
10. True-up Collected (Refunded)	161,204	161,204	(0)	0.0%	161,204	161,204	(0)	0.0%
11. End of Period - Total Net True-up (Lines D7 through D10)	$ (4,344,271)	$ 431,737	$ (4,776,008)	-1106.2%	$ (4,344,271)	$ 431,737	$ (4,776,008)	-1106.2%

* Jurisdictional Loss Multiplier

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Company: FLORIDA PUBLIC UTILITIES COMPANY

Division: **CONSOLIDATED ELECTRIC DIVISIONS**

Month of: **JANUARY 2020** **REVISED 7_27_2020**

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%
E. Interest Provision (Excluding GSLD)							--	--
1. Beginning True-up Amount (lines D-9 + 9a)	$ (3,952,348)	$ 666,626	$ (4,618,974)	-692.9%	N/A	N/A	--	--
2. Ending True-up Amount Before Interest	(4,338,778)	434,278	(4,773,056)	-1099.1%	N/A	N/A	--	--
(line D-7 + Lines D-9 + 9a + D-10)					N/A	N/A	--	--
3. Total of Beginning & Ending True-up Amount	(8,291,126)	1,100,904	(9,392,030)	-853.1%	N/A	N/A	--	--
4. Average True-up Amount (50% of Line E-3)	$ (4,145,563)	$ 550,452	$ (4,696,015)	-853.1%	N/A	N/A	--	--
5. Interest Rate - First Day Reporting Business Month	1.5900%	N/A	--	--	N/A	N/A	--	--
6. Interest Rate - First Day Subsequent Business Month	1.5900%	N/A	--	--	N/A	N/A	--	--
7. Total (Line E-5 + Line E-6)	3.1800%	N/A	--	--	N/A	N/A	--	--
8. Average Interest Rate (50% of Line E-7)	1.5900%	N/A	--	--	N/A	N/A	--	--
9. Monthly Average Interest Rate (Line E-8 / 12)	0.1325%	N/A	--	--	N/A	N/A	--	--
10. Interest Provision (Line E-4 x Line E-9)	(5,493)	N/A	--	--	N/A	N/A	--	--

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Company: **FLORIDA PUBLIC UTILITIES COMPANY**
CONSOLIDATED ELECTRIC DIVISIONS

Schedule A4

ELECTRIC ENERGY ACCOUNT
Month of: JANUARY 2020 REVISED 7_27_2020

			CURRENT MONTH				PERIOD TO DATE			
					DIFFERENCE				DIFFERENCE	
			ACTUAL	ESTIMATED	AMOUNT	%	ACTUAL	ESTIMATED	AMOUNT	%
	(MWH)									
1	System Net Generation		0	0	0	0.00%	0	0	0	0.00%
2	Power Sold									
3	Inadvertent Interchange Delivered - NET									
4	Purchased Power		35,128	27,981	7,147	25.54%	35,128	27,981	7,147	25.54%
4a	Energy Purchased For Qualifying Facilities		16,487	17,400	(913)	-5.25%	16,487	17,400	(913)	-5.25%
5	Economy Purchases									
6	Inadvertent Interchange Received - NET									
7	Net Energy for Load		51,615	45,381	6,235	13.74%	51,615	45,381	6,235	13.74%
8	Sales (Billed)		46,124	43,220	2,904	6.72%	46,124	43,220	2,904	6.72%
8a	Unbilled Sales Prior Month (Period)									
8b	Unbilled Sales Current Month (Period)									
9	Company Use		33	31	2	5.80%	33	31	2	5.80%
10	T&D Losses Estimated @	0.06	3,097	2,723	374	13.73%	3,097	2,723	374	13.73%
11	Unaccounted for Energy (estimated)		2,361	(594)	2,955	-497.71%	2,361	(594)	2,955	-497.71%
12										
13	% Company Use to NEL		0.06%	0.07%	-0.01%	-14.29%	0.06%	0.07%	-0.01%	-14.29%
14	% T&D Losses to NEL		6.00%	6.00%	0.00%	0.00%	6.00%	6.00%	0.00%	0.00%
15	% Unaccounted for Energy to NEL		4.57%	-1.31%	5.88%	-448.85%	4.57%	-1.31%	5.88%	-448.85%
	($)									
16	Fuel Cost of Sys Net Gen		-	-	-	0	-	-	-	0
16a	Fuel Related Transactions									
16b	Adjustments to Fuel Cost									
17	Fuel Cost of Power Sold									
18	Fuel Cost of Purchased Power		763,225	678,819	84,406	12.43%	763,225	678,819	84,406	12.43%
18a	Demand & Non Fuel Cost of Pur Power		1,422,373	1,485,147	(62,774)	-4.23%	1,422,373	1,485,147	(62,774)	-4.23%
18b	Energy Payments To Qualifying Facilities		1,171,582	1,392,584	(221,002)	-15.87%	1,171,582	1,392,584	(221,002)	-15.87%
19	Energy Cost of Economy Purch.									
20	Total Fuel & Net Power Transactions		3,357,180	3,556,550	(199,369)	-5.61%	3,357,180	3,556,550	(199,369)	-5.61%
	(Cents/KWH)									
21	Fuel Cost of Sys Net Gen									
21a	Fuel Related Transactions									
22	Fuel Cost of Power Sold									
23	Fuel Cost of Purchased Power		2.173	2.426	(0.253)	-10.43%	2.173	2.426	(0.253)	-10.43%
23a	Demand & Non Fuel Cost of Pur Power		4.049	5.308	(1.259)	-23.72%	4.049	5.308	(1.259)	-23.72%
23b	Energy Payments To Qualifying Facilities		7.106	8.003	(0.897)	-11.21%	7.106	8.003	(0.897)	-11.21%
24	Energy Cost of Economy Purch.									
25	Total Fuel & Net Power Transactions		6.504	7.837	(1.333)	-17.01%	6.504	7.837	(1.333)	-17.01%

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