



Dianne M. Triplett
DEPUTY GENERAL COUNSEL

June 26, 2024

VIA ELECTRONIC MAIL

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

Re: Docket 20240025-EI, Petition for Rate Increase by Duke Energy Florida, LLC

Dear Mr. Teitzman,

On June 11, 2024, the Office of Public Counsel ("OPC") submitted its confidential testimony and exhibits for James Dauphinais to Duke Energy Florida, LLC ("DEF") for review. On June 11, 2024, DEF filed its Notice of Intent to Request Confidential Classification regarding same.

On June 21, 2024, DEF electronically filed its Request Confidential Classification concerning the confidential information contained in Exhibit No. JRD-17 to the Direct Testimony of James R. Dauphinais.

DEF's June 21, 2024 redacted filing of the Direct Testimony and Exhibits of James R. Dauphinais, inadvertently omitted the headers. Enclosed for filing is the amended redacted Direct Testimony and Exhibits of James R. Dauphinais with headers.

Thank you for your assistance in this matter. Please feel free to call me at (727) 820-4692 should you have any questions concerning this filing.

Respectfully,

/s/ Dianne M. Triplett

Dianne M. Triplett

DMT/mh
Attachments

CERTIFICATE OF SERVICE

Docket No. 20240025-EI

I HEREBY CERTIFY that a true and correct copy of the foregoing has been furnished by electronic mail this 26th day of June, 2024, to the following:

/s/ Dianne M. Triplett

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PAUL RENNER
Speaker of the House of Representatives

June 11, 2024

CONFIDENTIAL DOCUMENT ATTACHED

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

Re: Docket No. 20240025 - EI

Dear Mr. Teitzman,

Please find enclosed for filing in the above referenced docket the **confidential** Direct Testimony and Exhibits of James R. Dauphinais. This filing is being hand delivered to the Clerk's Office and delivered to counsel for Duke Energy Florida, LLC (DEF). Counsel for DEF has agreed to serve a copy of the confidential testimony to all parties who have executed a non-disclosure agreement with DEF.

The testimony and exhibits of Mr. Dauphinais contain information that DEF has asserted to be confidential, and DEF has informed OPC that DEF will file a Notice of Intent to Request Confidential Classification of Mr. Dauphinais' testimony and exhibits. DEF will redact the material it claims to be confidential and file a redacted version of the testimony and exhibits with the Commission. It is our understanding that DEF will provide its request for confidentiality, including the highlighted confidential material and the accompanying detailed justification, in a separate filing. OPC reserves its right to challenge DEF's claims of confidentiality at the appropriate time.

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

Sincerely,

Walter Trierweiler
Public Counsel

/s/ Mary A. Wessling
Mary A. Wessling
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CERTIFICATE OF SERVICE
DOCKET NO. 20240025-EI

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* Not served at this time. One (1) copy of the confidential testimony has been filed with the PSC Clerk's Office under seal, pending confidentiality determination. DEF will serve Staff with a public version as soon as it becomes available.

**Counsel for DEF will serve those parties who have executed a non-disclosure agreement with DEF.

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****Counsel for DEF will serve those parties who have executed a non-disclosure agreement with DEF.**

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In Re: Petition for increase in rates
By Duke Energy Florida, LLC

DOCKET NO. 20240025-EI

FILED: June 11, 2024

CONFIDENTIAL PER DESIGNATION OF THE COMPANY

DIRECT TESTIMONY

OF

JAMES R. DAUPHINAIS

ON BEHALF

OF

THE CITIZENS OF THE STATE OF FLORIDA

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Qualifications of James R. Dauphinais Appendix A

LIST OF EXHIBITS

<u>Exhibit</u>	<u>Title</u>
Exhibit JRD-1	DEF Firm Capacity Need Timing for Summer Peak – 2023 TYSP
Exhibit JRD-2	DEF Firm Capacity Need Timing for Winter Peak – 2023 TYSP
Exhibit JRD-3	DEF Firm Capacity Need Timing for Summer Peak – 2024 TYSP
Exhibit JRD-4	DEF Firm Capacity Need Timing for Winter Peak – 2024 TYSP
Exhibit JRD-5	DEF Firm Capacity Need Timing for Summer Peak – 2023 TYSP – Bayboro P1-P4 CT Retirement Sensitivity
Exhibit JRD-6	DEF Firm Capacity Need Timing for Winter Peak – 2023 TYSP – Bayboro P1-P4 CT Retirement Sensitivity
Exhibit JRD-7	DEF Firm Capacity Need Timing for Summer Peak – 2024 TYSP – Bayboro P1-P4 CT Retirement Sensitivity
Exhibit JRD-8	DEF Firm Capacity Need Timing for Winter Peak – 2024 TYSP – Bayboro P1-P4 CT Retirement Sensitivity
Exhibit JRD-9	CCE Projects – CPVRR Breakeven
Exhibit JRD-10	CCE Projects – CPVRR Breakeven – OPC Estimate with Updated Capital Costs + Hypothetical Retirement of All CC Units by the end of 2041
Exhibit JRD-11	2025-2027 Solar Projects – Cost Effectiveness – OPC Estimate for Last Nine Projects
Exhibit JRD-12	2025-2027 Solar Projects – All 14 Projects Pursued – CPVRR Breakeven
Exhibit JRD-13	2025-2027 Solar Projects – All 14 Projects Pursued – CPVRR Breakeven -- OPC Estimate with Updated Capital Costs
Exhibit JRD-14	2025-2027 Solar Projects – All 14 Projects Pursued – CPVRR Breakeven – OPC Estimate with Updated Capital Costs and 2023 TYSP Low Fuel Costs
Exhibit JRD-15	Powerline Battery Project (40% ITC) – CPVRR Breakeven

- Exhibit JRD-16 Public Non-Voluminous Discovery Responses Cited to by Mr. Dauphinais in his Direct Testimony
- Exhibit JRD-17 Confidential Non-Voluminous Discovery Responses Cited to by Mr. Dauphinais in his Direct Testimony
- Exhibit JRD-18 Confidential Deposition Transcript Excerpts Cited to by Mr. Dauphinais in his Direct Testimony
- Exhibit JRD-19 Deposition Late Filed Exhibits Cited to by Mr. Dauphinais in his Direct Testimony

DIRECT TESTIMONY

OF

JAMES R. DAUPHINAIS

On Behalf of the Office of Public Counsel

Before the

Florida Public Service Commission

Docket No. 20240025-EI

I. INTRODUCTION

1

2 **Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.**

3 A. James R. Dauphinais. My business address is 16690 Swingley Ridge Road,
4 Suite 140, Chesterfield, MO 63017.

5

6 **Q. WHAT IS YOUR OCCUPATION?**

7 A. I am a consultant in the field of public utility regulation and a Managing
8 Principal of Brubaker & Associates, Inc. (“BAI”), energy, economic and regulatory
9 consultants.

10

11 **Q. ON WHOSE BEHALF ARE YOU APPEARING IN THIS PROCEEDING?**

12 A. I am appearing on behalf of the Florida Office of Public Counsel (“OPC”).

1 **Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND.**

2 A. In 1983, I graduated from Hartford State Technical College with an Associate's
3 Degree in Electrical Engineering Technology. Subsequently, I completed
4 undergraduate studies at the University of Hartford and was awarded a Bachelor's
5 Degree in Electrical Engineering. I have also completed graduate level courses in the
6 study of power system analysis, power system transients and power system protection
7 through the Engineering Outreach Program of the University of Idaho.

8

9 **Q. PLEASE DESCRIBE YOUR EXPERIENCE.**

10 A. I have over 39 years of experience in the electric utility industry, which began
11 with the start of my employment as an Engineering Technician in the Transmission
12 Planning Department of the Northeast Utilities Service Company (“NU,” now
13 “Eversource Energy”) in 1984. In 1990, upon the completion of my undergraduate
14 studies in electrical engineering, I was promoted to the position of Associate Engineer
15 within the Transmission Planning Department. By 1996, I had been promoted to the
16 position of Senior Engineer within the Transmission Planning Department.

17 In the employment of NU, I was responsible for conducting thermal, voltage
18 and stability analyses of the NU’s electric transmission system to support planning and
19 operating decisions. This involved the use of load flow, power system stability and
20 production cost computer simulations. It also involved examination of potential
21 solutions to operational and planning problems including, but not limited to,
22 transmission line solutions and the routes that might be utilized by such transmission
23 line solutions.

1 In 1997, I joined the firm of BAI. The firm includes consultants with
2 backgrounds in accounting, engineering, economics, mathematics, computer science
3 and business. Since my employment with the firm, I have been involved with a wide
4 variety of electric power and electric utility issues including, but not limited, to:
5 ancillary service rates, avoided cost calculations, certification of public convenience
6 and necessity, class cost of service, cost allocation, fuel adjustment clauses, fuel costs,
7 generation interconnection, interruptible rates, market power, market structure, off
8 system sales, prudence, purchased power costs, resource planning, rate design, retail
9 open access, standby rates, transmission losses, transmission planning, transmission
10 rates, and transmission line routing. I have provided expert testimony on all of the
11 foregoing. This expert testimony has been provided to the Federal Energy Regulatory
12 Commission (“FERC”) and the utility regulatory bodies of 21 states or provinces,
13 including the Florida Public Service Commission (“Commission” or “FPSC”). I
14 provide further information on my education and background in Appendix A to my
15 testimony.

16

17 **Q. PLEASE ELABORATE ON YOUR EXPERIENCE WITH RESPECT TO**
18 **RESOURCE PLANNING ISSUES.**

19 A. During my employment with NU, prior to the implementation of FERC Order
20 Nos. 888 and 889, the transmission planning organization within whom I was
21 employed was integrated with, and part of, the same functional organization as NU’s
22 generation planning organization. This integration led to significant involvement by
23 transmission planning, including myself, in resource planning analyses (e.g., the

1 analysis of the potential net benefit of retirement of existing generation resources) and
2 resource planning in transmission planning analyses (e.g., whether to proceed with
3 economic transmission upgrades). In addition, while employed at NU, I made
4 significant usage of the General Electric Company Multi-Area Production Simulator
5 (“MAPS”) to analyze the generation production costs associated with various
6 transmission operating and planning alternatives on the NU system.

7 Subsequently, during my employment with BAI since 1997, I have become
8 further involved with resource planning issues, initially in support of my colleagues at
9 BAI and later in a lead position. This work has included the review of electric utility
10 resource plans, the review of proposed certificates of public convenience and necessity
11 for new electric utility generation resources, the forecasting of future market prices, the
12 forecasting of future utility rates and the evaluation of long-term power supply options.
13 I have conducted this work both for intervenors in regulatory proceedings and specific
14 retail end-use customer clients of BAI who were evaluating their future power supply
15 options. I have also been extensively involved in the development of Independent
16 System Operator (“ISO”) and Regional Transmission Organization (“RTO”) -
17 administered power markets including, but not limited to, issues related to markets for
18 energy, operating reserves and capacity.

19

20 **Q. PLEASE IDENTIFY SOME OF THE CASES IN WHICH YOU PROVIDED**
21 **TESTIMONY WITH RESPECT TO RESOURCE PLANNING ISSUES.**

22 A. In the past 19 years, I have provided testimony on resource planning and/or the
23 prudency issues related to resource planning in Indiana Utility Regulatory Commission

1 (“IURC”) Cause No. 42643, Louisiana Public Service Commission (“LPSC”) Docket
2 No. U-30192, IURC Cause No. 43393, IURC Cause No. 43396, Colorado Public
3 Utilities Commission (“CPUC”) Docket Nos. 09A-324E and 09A-325E, IURC Cause
4 No. 43956, IURC Cause No. 44012, New Mexico Public Regulatory Commission
5 (“NMPRC”) Case No. 13-00390-UT, NMPRC Case No. 15-00261-UT, NMPRC Case
6 No. 17-00174-UT, NMPRC Case No. 19-00018-UT, NMPRC Case No. 19-00195-UT,
7 NMPRC Case No. 21-00083-UT, NMPRC Case No. 23-00353-UT, Michigan Public
8 Service Commission (“MPSC”) Case No. U-21090, MPSC Case No. U-21193, FPSC
9 Docket Nos. 160186-EI and 160170-EI (with respect to Scherer Unit 3 in the 2016 Gulf
10 Power Company base rate case), and FPSC Docket No. 20190061-EI (with respect to
11 Florida Power & Light Company’s SolarTogether Program and Tariff).

12 In a number of these proceedings, I had extensive involvement in the review of
13 the utility’s Aurora XMP®, EnCompass® or Strategist® resource planning analysis.
14 In the case of EnCompass® and Strategist®, this has included either me personally
15 running the modeling tool or having modeling runs performed under my direction and
16 supervision by other members of the BAI team, based upon data provided by subject
17 utility.¹ As discussed in the Direct Testimony of Duke Energy Florida, LLC (“DEF”

¹ Strategist®, which includes a module called Proview®, is a computer software tool produced by Ventyx that allows resource planners to examine a very large number of alternative resource portfolios with the goal of identifying through an optimization algorithm the most cost effective resource portfolio for an electric utility. It can also be used in a probabilistic mode to test the robustness (i.e., risk) of specific resource portfolios over a wide range of assumption variations. Strategist® is currently utilized, and has been utilized in the past, by many electric utilities to conduct their resource planning. Other commercial software tools that have some or all of the functionality of Strategist® include software tools such as System Optimizer®, PLEXOS®, Aurora XMP® and EnCompass®. Of these, Aurora XMP®, PLEXOS® and EnCompass® have become more commonly used in recent years due to their greater functionality and more robust solution technique.

1 or “Company”) witness Borsch, DEF uses EnCompass® to support its Integrated
2 Resource Planning (“IRP”) process.²

3

4 **Q. PLEASE EXPAND ON YOUR PREVIOUS EXPERIENCE WITH THE**
5 **ENCOMPASS MODELING TOOL THAT DEF USES IN ITS IRP PROCESS?**

6 A. I have received past training for EnCompass® from its vendor, Anchor Power
7 Solutions, and have personally run EnCompass® for resource optimization and
8 production cost analysis for testimony I have presented before the NMPRC and MPSC.

9

10 **Q. DO YOU HAVE PREVIOUS EXPERIENCE WITH STOCHASTIC LOSS OF**
11 **LOAD PROBABILITY (“LOLP”) ANALYSIS THAT IS COMMONLY USED**
12 **TO EVALUATE THE RESOURCE ADEQUACY OF ELECTRIC UTILITIES?**

13 A. Yes. I have received past training with respect to SERVM® – a software
14 modeling tool that was developed by Astrapé Consulting to perform LOLP analysis.
15 SERVM® is used by many utilities for LOLP analysis. In addition, I have had
16 members of the BAI staff perform SERVM® runs under my direction and supervision
17 for testimony I have presented before the NMPRC. Also, SERVM® is the primary
18 modeling tool used by the Midcontinent Independent System Operator, Inc. (“MISO”)
19 for the capacity accreditation and Loss of Load Expectation (“LOLE”) analysis it
20 presents to the MISO Resource Adequacy Subcommittee and the MISO Loss of Load
21 Expectation Working Group, both of which I regularly attend as a representative of

² Borsch Direct at 17.

1 large end-use customer groups located in Illinois, Indiana, Louisiana, Michigan and
2 Texas.

3 **Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY IN THIS**
4 **DOCKET?**

5 A. I present testimony with respect to the prudence, reasonableness, and cost
6 effectiveness of DEF's already incurred and proposed investments for the following
7 supply-side resource projects:

- 8 • DEF's currently estimated \$154.9 million investment in Combined Cycle
9 Generation Efficiency Improvement Projects ("CCE Projects") that are currently
10 expected to be fully completed by the end of 2026.^{3,4}
- 11 • DEF's currently estimated \$1.663 billion investment in 14 proposed new
12 74.9 MW_{AC} solar photovoltaic generation facilities that are currently projected to
13 enter service between 2025 and 2027 ("2025-2027 Solar Projects").⁵
- 14 • DEF's currently estimated \$164.5 million investment in its proposed Powerline
15 100 MW, 2-hour Battery Storage facility that it projects to enter service in 2027
16 ("Powerline Battery Project").⁶

17 DEF's 2024 Ten-Year Site Plan ("TYSP") estimate of the total firm capacity
18 that would be provided by these projects is summarized below.

³ Anderson Exhibit RDA-3 and DEF Response to OPC ROG No. 118 (Amended on June 7, 2024).

⁴ When I use the words "current" and "currently" in this direct testimony, it means current or currently as of the filing date of this direct testimony based on the latest information provided by DEF through discovery and depositions.

⁵ DEF Response to OPC ROG No. 118 (Amended on June 7, 2024) and Confidential DEF Response to OPC ROG No. 186.

⁶ Jacob Direct at 5.

TABLE JRD-1		
<u>Estimated Total Firm Capacity</u>		
(MW)		
	<u>Summer</u>	<u>Winter</u>
CCE Projects	389	347
2025-2027 Solar Projects	262	0
Powerline Battery Project	90	90
Source: DEF 2024 TYSP, April 22, 2024 at Schedule 8		

1 Collectively, these projects represent the largest driver of the increase in DEF’s
 2 rate base in its three proposed projected test years for this base rate proceeding
 3 (calendar years 2025, 2026 and 2027).

4 Note that the scope of my direct testimony does not go toward the issue of
 5 whether DEF should be permitted to have multiple projected test years or to the proper
 6 level of projected capital expenditures for the CCE Projects, 2025-2027 Solar Projects
 7 or the Powerline Battery Project that should be utilized in each proposed projected test
 8 year for setting base rates for those projected test years. Those are extremely important
 9 questions in this proceeding as they present a serious risk of over-recovery particularly
 10 with respect to DEF potentially later delaying its projected investments, later delaying
 11 the projected in-service date of its projected investments, or ultimately not even making
 12 its projected investments. These issues are addressed by other OPC witnesses besides
 13 myself. My direct testimony instead concentrates on whether these investments once
 14 they enter service should be allowed to be reflected in projected test year revenue

1 requirements at all assuming the Commission grants DEF rates based on three projected
2 test years.

3 Finally, the fact that I do not address any other particular issues in my testimony
4 or am silent with respect to any portion of DEF's Petition or direct testimony in this
5 proceeding should not be interpreted as an approval of any position taken by DEF.

6

7 **Q. WHAT DID YOU REVIEW PRIOR TO PREPARING YOUR DIRECT**
8 **TESTIMONY?**

9 A. I reviewed DEF's petition in this proceeding along with the direct testimony in
10 this proceeding of DEF witnesses Olivier, Panizza, Goff, Jacob, Anderson, Borsch, and
11 Seixas. I have also reviewed DEF's responses to discovery in this proceeding regarding
12 the issues of resource planning, Investment Tax Credits ("ITCs"), Production Tax
13 Credits ("PTCs"), the CCE Projects, the 2025-2027 Solar Projects and the Powerline
14 Battery Project. I also listened to, or reviewed the transcription of, the May 2024
15 depositions in this proceeding of DEF witnesses Goff, Jacob, Anderson and Borsch.
16 Finally, I reviewed the 2023 TYSP and 2024 TYSP of DEF.

17

18 **Q. BEFORE YOU SUMMARIZE YOUR CONCLUSIONS AND**
19 **RECOMMENDATIONS, DO YOU HAVE ANY CAVEATS YOU WOULD**
20 **LIKE TO PUT ON THEM?**

21 A. Yes. The compressed procedural schedule in this proceeding for filing
22 Intervenor testimony has limited the time to complete OPC's investigation into the
23 issues and effects of those issues on the Company's petition. With respect to my

1 particular review of the Company’s petition, direct testimony and exhibits, and
2 responses to discovery, I have been left with two unresolved issues at the time of the
3 filing of this direct testimony.

4 The first relates to a discrepancy between the peak demand, coincident peak
5 demand and available capacity in DEF’s EnCompass® modeling runs versus what is
6 reported in DEF’s TYSPs. This discrepancy exists even though there appears to be no
7 similar discrepancy with respect to annual energy.

8 The second unresolved issue pertains to the lack of a cost-effectiveness
9 analysis, including Cumulative Present Value Revenue Requirement (“CPVRR”)
10 benefit to cost ratio and breakeven calculations, for the latest two of the fourteen solar
11 projects DEF has proposed in this proceeding.

12 Both of these unresolved issues are continuing to be pursued by OPC in
13 discovery of DEF. The results of that additional discovery may lead to one or more
14 changes to my conclusions and recommendations within this testimony.
15 Consequently, it is my understanding that OPC reserves the right to file supplemental
16 testimony to fully address these unresolved issues and the effects of those unresolved
17 issues, if necessary.

18

19 **Q. PLEASE SUMMARIZE YOUR CONCLUSIONS AND**
20 **RECOMMENDATIONS.**

21 A. With the caveats I have given, my conclusions and recommendations can be
22 summarized as follows:

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- DEF’s CCE Projects, 2025-2027 Solar Projects and Powerline Battery Project each provide firm capacity to DEF nearly three years earlier than necessary for resource adequacy and as such are not necessary for reliability at this time;
- Therefore, they are elective rather than mandatory for their projected in-service dates;
- In order for the pursuit of generation-related projects such as these that are elective to be prudent and reasonable, they need to be otherwise shown consistent with providing reliable electric service at lowest reasonable cost;
- This requires a demonstration that the projects are for the purpose of serving DEF’s customers – not off-system sales – and that there is a robust, essentially “no regrets,” economic case for them;
- The demonstration of a robust economic case is required because DEF’s customers do not take service from DEF in order to participate in speculative investments but rather to receive reliable electric service at lowest reasonable cost;
- The demonstration is also necessary to ensure the balance of risk for the subject investments is reasonably balanced between DEF and its customers;
- While the CCE Projects are not necessary for reliability at this time, my review of DEF’s cost effectiveness analysis shows these projects are for the purpose of serving DEF’s customers and are reasonably forecasted to provide a very robust net benefit such that DEF’s decision to pursue them with 2023 through 2026 in-service dates was prudent and reasonable;
- While the 2025-2027 Solar Projects are not necessary for reliability at this time, my review of DEF’s cost effectiveness analysis shows that 12 of these 14 projects are for purpose of serving DEF’s customers and are reasonably forecasted to provide a robust net benefit such that DEF’s decision to pursue these 12 projects with 2025 through 2026 in-service dates was prudent and reasonable;
- There is evidence to suggest the forecasted net benefit for the remaining two 2025-2027 Solar Projects is not robust such that DEF’s decision to pursue them may not be prudent and reasonable – additional cost-effectiveness analysis needs to be performed by DEF before it can be found that DEF’s decision to pursue them with a projected 2027 in-service date was just and reasonable;
- Until it can be found DEF’s decision to pursue the last two 2025-2027 Solar Projects with a 2027 in-service date was prudent and reasonable, DEF’s decision with respect to the two projects should be deemed not prudent or

1 reasonable and the projected costs for the two projects be entirely removed from
2 DEF's proposed projected test years in this proceeding;

- 3
- 4 • The Powerline Battery Project is not necessary for reliability at this time and
5 DEF's cost effectiveness analysis shows that it is not forecasted to provide a
6 robust economic benefit such that there is a significant risk it could result in a
7 net cost rather than a net benefit;
 - 8
 - 9 • As a result, DEF's decision to pursue the Powerline Battery Project with a
10 projected 2027 in-service date was not prudent or reasonable;
 - 11
 - 12 • Therefore, the projected costs for the Powerline Battery Project should be
13 entirely removed from DEF's proposed projected test years in this proceeding.
14

15 **II. TIMING OF DEF'S FIRM CAPACITY NEED**

16 **Q. PLEASE EXPLAIN HOW YOU REVIEWED THE PRUDENCE,**
17 **REASONABLENESS AND COST-EFFECTIVENESS OF DEF'S ALREADY**
18 **INCURRED AND PROJECTED INVESTMENTS FOR ITS CCE PROJECTS,**
19 **2025-2027 SOLAR PROJECTS, AND POWERLINE BATTERY PROJECT.**

20 A. I started by examining the timing of DEF's forecasted need for additional firm
21 generation capacity and then examined DEF's forecasted economic performance for
22 each of the investments.

23

24 **Q. PLEASE EXPLAIN HOW THE TIMING OF DEF'S NEED FOR ADDITIONAL**
25 **FIRM GENERATION CAPACITY AFFECTS THE PRUDENCE,**
26 **REASONABLENESS, AND COST-EFFECTIVENESS OF DEF'S PROPOSED**
27 **INVESTMENTS IN THESE PROJECTS.**

28 A. To the extent the firm generation capacity that would be provided by these
29 projects is actually substantially needed immediately, or nearly immediately, following
30 their entrance to service, there is a demonstrated reliability need for the firm capacity

1 provided by them by the end of DEF's projected test years in this proceeding. Under
2 that scenario, the pursuit of them would be consistent with providing reliable electric
3 service at the lowest reasonable cost to DEF's customers provided the projects have a
4 lower Cumulative Present Value Revenue Requirement ("CPVRR") than other
5 alternatives available to DEF that would provide a similar amount of firm generation
6 capacity at a comparable level of risk.

7 However, if the firm generation capacity that would be provided by the projects
8 is not substantially immediately needed, or nearly immediately needed, the pursuit of
9 the projects in question by DEF with the timing that DEF has proposed would not
10 necessarily be consistent with providing reliable electric service at lowest reasonable
11 cost even if the investments are projected to provide a lower CPVRR for DEF. This is
12 because there is not a reliability justification for the projects that makes them
13 mandatory. Instead, they are elective. As elective projects, it would need to be
14 demonstrated the projects are in fact for the purpose of serving DEF's customers (i.e.,
15 not for the purpose of DEF making off-system sales at wholesale). Furthermore, since
16 projected cost savings would be the principal driver of pursuing these elective projects,
17 it also needs to be demonstrated the projected CPVRR net benefit of the proposed
18 projects, over alternatives to them that have an in-service date consistent with the
19 timing of DEF's firm capacity need, is robust enough such that the investments are not
20 speculative in nature and the balance of risk between DEF and its customers for the
21 investments is reasonable.

22 Specifically, the economic analysis should exclude off-system sales margins
23 (including any Production Tax Credits ("PTC") enabled by off-system sales), the

1 benefit to cost ratio for the investment should be robust (ideally 1.25 or higher, but at
2 least 1.15), and a net CPVRR benefit from the investment be projected to be provided
3 to customers no later than half-way through the life of the investment in question and
4 no longer than 10 years after the investment enters service. The first criterion ensures
5 the projects are being cost justified based on serving the load of DEF's customers rather
6 than speculative off-system sales. The latter two criterion ensure the projects are
7 essentially "no regrets" investments for DEF's customers.

8

9 **Q. WHY IS IT IMPORTANT THAT DEF'S GENERATION OR RESOURCE**
10 **INVESTMENTS THAT ARE ELECTIVE, BE "NO REGRETS"**
11 **INVESTMENTS FOR DEF'S CUSTOMERS?**

12 A. It goes to the issues of the purpose of regulated electric service and the balance
13 of risk between a utility and its customers. DEF's customers are not customers of DEF
14 for the purpose of making speculative investments. They are customers of DEF for the
15 purpose of receiving reliable electric service at the lowest reasonable cost. Hence, any
16 elective investments DEF makes to provide that service need to have a low risk and
17 thus have "no regrets" associated with them. With respect to balancing risk, DEF
18 afforded an opportunity to earn its authorized return on the investments through its base
19 rates whether or not the investments actually provide net savings for DEF's customers.
20 Thus, to keep the balance of risk between DEF and its customers reasonable, the
21 investments made by DEF once again must be of the "no regrets" nature.

1 **Q. WHAT IS THE BASIS OF YOUR 1.25 AND 1.15 BENEFIT TO COST RATIO**
2 **THRESHOLD?**

3 A. MISO requires a 20-year CPVRR Benefit to Cost Ratio of at least 1.25 for
4 transmission projects pursued as Market Efficiency Projects (“MEP”). These are
5 transmission projects that are solely being pursued for economic reasons.⁷ PJM
6 Interconnection, LLC (“PJM”) uses the same threshold for economic-based
7 transmission enhancements.⁸ ERCOT uses a threshold benefit to cost ratio of 1.15 for
8 such projects.

9
10 **Q. WHY IS IT IMPORTANT FOR AN EARLY CPVRR BREAKEVEN YEAR TO**
11 **BE MET IN ADDITION TO MEETING A MINIMUM BENEFIT TO COST**
12 **RATIO?**

13 A. It complements the minimum benefit to cost ratio by addressing the issue of
14 there being less certainty about the future as you go out in time. There is much more
15 risk with a net benefit actually being realized from a project that is not forecasted to
16 provide a net benefit until many years from now versus one that has a forecast net
17 benefit in just a few years.

18
19 **Q. PLEASE EXPLAIN HOW DEF CURRENTLY DETERMINES ITS FIRM**
20 **CAPACITY NEED.**

21 A. DEF applies deterministic and probabilistic criteria to ensure it has sufficient
22 firm capacity, and, thus, resource adequacy, to meet its forecasted load under its

⁷ MISO Tariff Attachment FF-Transmission Expansion Planning Protocol Section II (B)(e).

⁸ PJM Manual 14B: PJM Region Transmission Planning Process.

1 TYSPs. The *deterministic* criterion that DEF uses is to carry extra summer and winter
2 firm capacity known as Planning Reserve Margin (“PRM”) in an amount equal or
3 greater than 20% of the forecasted firm summer and winter demand of its customers.
4 The *probabilistic* criterion that DEF uses is to carry sufficient extra firm summer and
5 winter capacity to ensure the forecasted LOLP for its firm load is no greater than one
6 loss of load event day in 10 years. DEF’s reports its approach is to meet both of these
7 criteria and that it has used this dual reliability criteria approach in its annual TYSPs
8 since the early 1990s. However, it also reports that typically the 20% PRM criterion
9 has triggered resource additions for DEF before the LOLP criterion has become a factor
10 and that a probabilistic analysis is periodically performed to ensure the LOLP criterion
11 is satisfied.⁹

12
13 **Q. HAS DEF PROVIDED ANY INFORMATION WITH RESPECT TO THE**
14 **MOST RECENT PROBABILISTIC ANALYSIS THAT HAS BEEN**
15 **PERFORMED?**

16 A. Yes. DEF indicates it has not prepared a utility of Balancing Authority Area
17 (“BAA”) specific LOLP study in the last several years. Instead, DEF indicates that
18 because of the high level of integration of the DEF system into the overall Florida
19 Reliability Coordinating Council, Inc. (“FRCC”) system, the extensive use of reserve
20 sharing and the existence of a single reliability coordinator for the state, it is more
21 relevant to evaluate LOLP on a state-wide basis and the FRCC does such an analysis
22 every other year in even numbered years.¹⁰ DEF also reports the most recent FRCC

⁹ Borsch Direct at 8-9.

¹⁰ DEF Response to LULAC/FR ROG No. 9.

1 LOLP study from 2022 reported the following forecasted results for the FRCC region
 2 as a whole for 2022 through 2026.¹¹

TABLE JRD-2
2022 FRCC LOLP Results

<u>Year</u>	<u>Base Case</u>	<u>No Availability of Firm Imports</u>	<u>No Availability of Demand Response</u>	<u>High Case</u>
	LOLP (Days/Year)	LOLP (Days/Year)	LOLP (Days/Year)	LOLP (Days/Year)
2022	0.000003	0.000957	0.015117	0.000008
2023	0.000003	0.000441	0.015003	0.000008
2024	0.000002	0.000652	0.014572	0.000009
2025	0.000004	0.000688	0.010994	0.000011
2026	0.000002	0.000597	0.008826	0.000009

Source: DEF Response to LULAC/FR ROG No. 9

3
 4 **Q. THE RESULTS IN YOUR TABLE JRD-2 ABOVE ARE IN TERMS OF DAYS**
 5 **PER YEAR. WHAT DOES THIS TRANSLATE INTO ON A DAYS IN TEN**
 6 **YEARS BASIS?**

7 A. One event day in ten years translates into a LOLP of 0.1 days per year. Thus,
 8 the results in Table JRD-2 indicate the FRCC in its 2022 LOLP Study forecasted
 9 LOLPs that range from one event day in 500,000 years (for the Base Case for 2026) to
 10 one event day in 66.2 years (for No Availability of Demand Response for 2022). These
 11 LOLP values are well, well below the one day in ten years target that is the industry

¹¹ DEF Response to LULAC/FR ROG No. 9.

1 standard. This suggests the overall FRCC region has large amounts of excess firm
2 capacity, the 20% PRM criterion used by individual Florida utilities such as DEF is
3 more conservative than necessary, or some combination of the two.

4

5 **Q. WHAT DOES IT MEAN WITH RESPECT TO THIS PROCEEDING?**

6 A. Given DEF's long history of its 20% PRM criterion driving its firm capacity
7 need rather than LOLP study results, the very low forecasted LOLP values being
8 reported for the FRCC region as a whole by FRCC, and DEF's own statements with
9 respect to the tightly integrated nature of the overall FRCC system that DEF is part of,
10 DEF has no need to carry very much, if any, firm capacity in excess of its 20% PRM
11 to maintain a LOLP less than or equal to one day in ten years. The 20% PRM already
12 provides a very large insurance policy to ensure the industry standard one day in ten
13 years LOLP target is met by DEF.

14

15 **Q. DOES DEF CALCULATE THE FIRM CAPACITY FOR SOLAR**
16 **GENERATION FACILITIES AND BATTERY STORAGE FACILITIES IN**
17 **THE SAME MANNER AS IT DOES FOR ITS CONVENTIONAL**
18 **GENERATION FACILITIES?**

19 A. No. Since they are always available to provide their summer and winter rated
20 capacity in all hours within the bounds startup, shutdown and ramp rate constraints
21 except when on outage, DEF determines the summer and winter firm capacity of its
22 conventional generation facilities based on the summer and winter rated capability of
23 those facilities. However, since solar generation output depends on the presence, level

1 and angle of sunshine and battery storage facilities have limited energy available for
 2 discharge, DEF derates the summer and winter firm capacity for these resources from
 3 the rated capability of these resources. For solar generation, it has performed an
 4 analysis that accounts for the shifting of the time of its net peak in summer as it has
 5 higher levels of solar generation penetration.¹² Specifically, DEF arrived at the
 6 following estimate of summer firm capacity as a percentage of nameplate capacity for
 7 new solar resources as a function of total installed solar generation on its system.

TABLE JRD-3	
<u>Solar Firmness</u>	<u>Solar Up to MWs</u>
57.0%	1,500
25.0%	2,400
12.5%	3,250
10.0%	5,500

Source: DEF's response to
LULAC/FR ROG No. 12

8

9 **Q. CAN YOU EXPLAIN HOW THIS TABLE WORKS?**

10 A. Yes. The first 1,500 MW of solar generation receives a summer firm capacity
 11 of 57% of nameplate. The next 900 MW of solar generation receives a summer firm
 12 capacity of 25% of nameplate. Then, the next 850 MW of solar generation receives a
 13 summer firm capacity of 12.5% of nameplate, and so on.

¹² The net peak is the peak demand placed on DEF's non-solar resources after accounting for solar generation including retail customer rooftop solar facilities.

1 **Q. HOW MUCH WINTER FIRM CAPACITY IS ASSUMED BY DEF TO BE**
2 **PROVIDED FROM THE SOLAR GENERATION FACILITIES?**

3 A. None. This is because DEF's forecasted winter peak occurs in darkness.¹³
4

5 **Q. BASED ON YOUR EXPERIENCE, IS DEF'S APPROACH FOR SOLAR**
6 **GENERATION UNREASONABLE?**

7 A. Given there is currently very little battery storage capacity or wind generation
8 on the DEF system and the period of interest for this proceeding only involves through
9 2027 and very shortly thereafter, firm capacity diversity benefits do not need to be
10 considered. Therefore, I cannot say that DEF's approach is an unreasonable approach
11 to properly account for the diminishing value of solar generation toward reducing
12 LOLP during summer periods as the total penetration of solar generation increases.
13

14 **Q. WHAT APPROACH DOES DEF USE FOR BATTERY STORAGE?**

15 A. Based on a study performed by one of its sister companies in the Carolinas,
16 DEF assumes 90% of nameplate capacity for both summer and winter firm capacity
17 and does so for both two-hour and four-hour storage.
18

19 **Q. IS THIS A REASONABLE APPROACH?**

20 A. No. A two-hour battery can only provide 50% of its nameplate capacity when
21 discharged over four hours. Given this, DEF should have used a lower percentage of
22 nameplate capacity for two-hour battery facilities, such as its proposed Powerline

¹³ DEF Response to OPC ROG No. 75.

1 Battery Facility, potentially as low as 45% (half of 90%), given its much lesser ability
2 to sustain a discharge at its nameplate capacity versus four-hour battery facilities. I
3 will address this further when I address the forecasted economics of the Powerline
4 Battery Project later in my testimony.

5

6 **Q. PLEASE EXPLAIN HOW YOU SPECIFICALLY EXAMINED THE TIMING**
7 **OF DEF'S NEED FOR ADDITIONAL FIRM CAPACITY.**

8 A. I performed an analysis for both DEF's 2023 and 2024 TYSPs. Specifically, I
9 created a modified version of Schedules 7.1 and 7.2 of DEF's TYSP that backs out the
10 summer and winter firm capacity indicated in Schedule 8 of DEF's TYSP that is
11 associated with the CCE Projects, the 2025-2027 Solar Projects, the Powerline Battery
12 Project and the planned resource placeholders that would later enter service that DEF
13 included in its TYSP but is not seeking approval of in this proceeding. I then delayed
14 DEF's planned 2026-2027 retirement in its TYSP of certain combustion turbine
15 generation facilities by three years. With that baseline established, I identified the year
16 when DEF's need for additional firm capacity to meet its 20% PRM first reaches the
17 amount expected in the TYSP from the CCE Projects, then in the amount expected
18 from the TYSP from the 2025-2027 Solar Projects and then finally the amount expected
19 in the TYSP from the Powerline Battery Project. This order reflects the order of the
20 expected in-service dates of these projects.

21 The results of this analysis, which is summarized in Exhibits JRD-1 through
22 JRD-4 indicates that the summer drives the need for additional firm capacity. In
23 addition, it shows the firm capacity expected from the CCE Projects is not needed until

1 2029 and the firm capacity expected from the 2025-2027 Solar Projects and Powerline
2 Battery Project is not needed until 2030. Hence, the results of my analysis is as follows:

- 3 • The firm capacity expected from the CCE Projects would not be needed until 2029,
4 nearly three years after the last of them is expected to enter service in 2026;
- 5 • The firm capacity expected from the years 2025-2027 Solar projects would not be
6 needed until 2030, nearly three years after the last of the projects is expected to
7 enter service in 2027; and
- 8 • The firm capacity expected from the Powerline Battery Project would not be needed
9 until 2030, nearly three years after it is proposed to enter service in 2027.

10 Given these results, the firm capacity that would be provided from these
11 projects would not be needed for reliability shortly after the projects enter service.
12 They would not be needed for reliability until nearly three years past the respective
13 expected in-service dates of the projects. As such, completion of these projects by their
14 projected in-service dates is not necessary for reliability. Hence, the projects at this
15 time are elective rather than mandatory. Therefore, they must be solely justified on the
16 basis of economics, and, as I have discussed, to ensure the projects are consistent with
17 providing reliable electric service at lowest reasonable cost, their economics need to be
18 based on serving DEF's customers, not on off-system sales, and those economics need
19 to be robust.

20

21 **Q. PLEASE EXPLAIN WHY YOU PERFORMED YOUR DEF FIRM CAPACITY**
22 **NEED TIMING ANALYSIS FOR BOTH DEF'S 2023 AND 2024 TYSPs AND**
23 **NOT JUST DEF'S 2024 TYSP.**

24 A. While DEF's direct testimony and exhibits in this proceeding were dated April
25 2, 2024, the day after DEF initially filed its 2024 TYSP with the Commission, as

1 evidenced by the economic analysis DEF produced in discovery for the CCE Projects,
2 2025-2027 Solar Projects, Powerline Battery Project, DEF's 2023 TYSP, and DEF
3 witness Borsch's direct testimony, DEF made its initial decision to pursue the CCE
4 Projects, 2025-2027 Solar Projects, and the Powerline Battery Project prior to the
5 development of DEF's 2024 TYSP. Based on my many years of regulatory experience,
6 my understanding is, under the prudence standard, the reasonableness of actions taken,
7 or not taken, by a utility is reviewed based on information known, or knowable, at the
8 time the decision was made. The reasonableness of a utility's actions, or lack of
9 actions, should be judged in light of the circumstances and facts known, or knowable,
10 at the time that the decision was made. Prudence does not permit "hindsight" review
11 of the actions taken. Thus, for that portion of the Company's costs for the projects that
12 were committed prior to its 2024 TYSP, we need to examine DEF's 2023 TYSP since
13 that was available to DEF's decision makers at that time. This said, the 2024 TYSP is
14 relevant with respect to the costs for the projects DEF has not yet committed to
15 incurring.

16

17 **Q. PLEASE EXPLAIN WHY YOU INCLUDED A THREE-YEAR DELAY OF**
18 **DEF'S PLANNED 2026-2027 COMBUSTION TURBINE RETIREMENTS IN**
19 **YOUR FIRM CAPACITY NEED TIMING ANALYSIS.**

20 A. DEF has indicated it has performed no cost effectiveness analysis for those
21 planned retirements, which total to 524 MW of summer firm capacity in the DEF 2023
22 TYSP and 460 MW of summer firm capacity in the DEF 2024 TYSP.¹⁴ In addition,

¹⁴ DEF 2023 TYSP at Schedule 8 and Confidential Video-Conference Deposition of Borsch, May 30, 2024, Transcript Volume II at 74:9 through 76:21.

1 while DEF has indicated there is a significant environmental risk need for the Bayboro
2 portion of these facilities, for the rest of these combustion turbines, DEF indicated the
3 trigger mechanism for their planned retirement is DEF being in a period of relatively
4 high reserve margins.¹⁵ Thus, the planned 2026-2027 retirement of the combustion
5 turbine generation in question is predominantly driven by DEF having excess firm
6 capacity – excess firm capacity contributed to by the proposed CCE Projects, 2025-
7 2027 Solar Projects, and the Powerline Battery Project. Therefore, I conservatively
8 assumed DEF would be able to delay the planned retirement of these combustion
9 turbine generation facilities by at least three years if it needed the firm capacity
10 provided by them.

11
12 **Q. WHAT IF THE BAYBORO PORTION OF THE PLANNED 2026-2027**
13 **COMBUSTION TURBINE RETIREMENTS CANNOT BE DELAYED BY AT**
14 **LEAST THREE YEARS DUE TO THE ENVIRONMENTAL RISK**
15 **ASSOCIATED WITH THEM IDENTIFIED BY DEF?**

16 A. At the outset, it is important to note that between its 2023 and 2024 TYSPs,
17 DEF has already shown a willingness to delay the retirement of the Bayboro
18 combustion turbines in question by some amount of time as the planned retirement date
19 for them in the 2023 TYSP was December 2025, while in the 2024 TYSP it is now
20 October 2026.¹⁶ Given this, I believe my three-year retirement delay assumption is
21 reasonably applied to the Bayboro combustion turbine units in question.

¹⁵ Confidential Video-Conference Deposition of Borsch, May 30, 2024, Transcript Volume II at 74:9 through 76:21.

¹⁶ DEF 2023 TYSP and 2024 TYSP at Schedule 8.

1 This said, I have performed a sensitivity analysis with respect to the timing of
2 DEF's capacity need where the planned retirement of the Bayboro combustion turbine
3 units in question is not delayed by three years. The results of this sensitivity analysis,
4 which are summarized in Exhibits JRD-5 through JRD-8, indicate that, if the planned
5 retirement date of the Bayboro combustion turbines in question cannot be delayed by
6 at least three years, the firm capacity provided by the CCE Projects could be needed by
7 DEF as soon as 2027, the year following the last of them entering service in 2026.
8 However, the firm capacity from the 2025-2027 Solar Projects and Powerline Battery
9 Project would continue to not be needed until 2030 – nearly three years after the last of
10 these projects enter service.

11 Note the changed result with respect to the timing of the need for the firm
12 capacity that would be provided by the CCE Projects would not change my ultimate
13 conclusion in this direct testimony that DEF's decision to pursue the CCE Projects with
14 2023 through 2026 in-service dates was prudent and reasonable. It would just
15 strengthen my ultimate conclusion for the CCE Projects since the CCE Projects, in
16 addition to being for the purpose of serving DEF's customers and having a very robust
17 economic case for them as I have found, would now also be needed for reliability
18 purposes very shortly after the last of them enters service.

1 **Q. IS THERE ANY ADDITIONAL EVIDENCE SUPPORTING YOUR**
2 **CONCLUSION THAT THE FIRM CAPACITY THAT WOULD BE**
3 **PROVIDED BY THE CCE PROJECTS WILL NOT BE NEEDED UNTIL 2029,**
4 **THAT THE FIRM CAPACITY THAT WOULD NOT BE NEEDED FROM THE**
5 **2025-2027 SOLAR PROJECTS WOULD NOT BE NEEDED UNTIL 2030, AND**
6 **THAT THE FIRM CAPACITY THAT WOULD BE PROVIDED BY THE**
7 **POWERLINE BATTERY PROJECT WOULD NOT BE NEED UNTIL 2030?**

8 A. Yes. The alternative projects DEF used in its economic analysis of the CCE
9 Projects would not enter service until 2029 and 2033. The alternative projects DEF
10 used in its economic analysis of the 2025-2027 Solar Projects would not enter service
11 until 2030 and 2032. Finally, the alternative projects DEF used in its economic analysis
12 of the Powerline Battery Project would not enter service until 2030 and 2031.¹⁷

13 This further substantiates the conclusion of my analysis above that DEF will
14 not need the firm capacity from the CCE Projects, 2025-2027 Solar Projects and
15 Powerline Battery Project until nearly three years after their respective expected project
16 in-service dates given the alternatives DEF utilized would not enter service until nearly
17 three years after the projects DEF was studying.

¹⁷ DEF Response to LULAC/FR POD No. 2 at Projects tab of '2024 Rate Case CC HR Upgrade Study CPVRR Results.xlsx', '2024 Rate Case Solar Study CPVRR Results.xlsx' and '2024 Rate Case Battery Study CPVRR Results.xlsx'.

1 **Q. PLEASE SUMMARIZE YOUR CONCLUSION WITH RESPECT TO THE**
2 **ISSUE OF THE TIMING OF DEF'S CAPACITY NEED.**

3 A. The evidence shows that, while DEF uses a combination of deterministic and
4 probabilistic criteria to ensure resource adequacy, in practice its 20% PRM
5 deterministic criterion has alone driven firm capacity additions for DEF. In addition,
6 the FRCC region as a whole has a LOLP of well below the industry standard one event
7 day in 10 years target. As a result, DEF needs very little, if any, firm capacity beyond
8 that necessary to provide it a 20% PRM.

9 DEF's derate of the rated capability of solar generation when determining the
10 summer and winter firm capacity provided by the same is not unreasonable.

11 DEF's derate of the rated capability of two-hour battery storage, such as the
12 proposed Powerline Battery project, should be lower than that for four-hour battery
13 storage given only half the rated capability of two-hour battery storage over a four-hour
14 discharge period.

15 My analysis of DEF's 2023 TYSP and 2024 TYSP shows that DEF does not
16 need the firm capacity that would be provided by its CCE Projects, 2025-2027 Solar
17 Projects and Powerline Battery Projects to meet its 20% PRM criterion for resource
18 adequacy until three years after the respective projected in-service dates of these
19 projects. Given this, they are not required for reliability at the time of their respective
20 in-service dates and thus pursuit of them under their projected in-service dates makes
21 them elective rather than mandatory projects.

22 For the pursuit of these elective projects to be consistent with providing reliable
23 electric service at lowest reasonable cost, it needs to be shown they will for the purpose

1 of serving DEF's customers (i.e., not to make off-system sales) and that the economic
2 case for them is robust. A robust economic case needs to be demonstrated because
3 DEF's customers are not customers of DEF for the purpose of participating in
4 speculative investments but rather to obtain reliable electric service at lowest
5 reasonable cost. It also needs to be demonstrated to ensure a reasonable balance of risk
6 between DEF and its customers.

7 To demonstrate a robust economic case, the projects should ideally have a
8 CPVRR benefit to cost ratio of 1.25 or more, but at least no less than 1.15, versus
9 alternatives (with a comparable level of risk that would not enter service until the year
10 DEF needs firm capacity from them) to help ensure the project will in fact ultimately
11 provide a net benefit to DEF customers. In addition, to further ensure this, the projects
12 should break even on a CPVRR basis versus other alternatives (with a comparable level
13 of risk that would not enter service until the year DEF needs firm capacity from them)
14 within half the design life of the projects and in no case less than 10 years after they
15 enter service. All of this will ensure the projects are "no regrets" projects for the
16 purpose of serving DEF's customers such that they are consistent with providing
17 reliable electric service at the lowest reasonable cost.

1 **III. FORECASTED ECONOMIC PERFORMANCE OF THE CCE PROJECTS**

2 **Q. YOU HAVE CONCLUDED THE CCE PROJECTS WITH THEIR**
3 **PROJECTED IN-SERVICE DATES ARE NOT NECESSARY FOR**
4 **RELIABILITY AT THIS TIME AND THEREFORE MUST BE SHOWN TO BE**
5 **FOR THE PURPOSE SERVING DEF'S CUSTOMERS, RATHER THAN FOR**
6 **OFF-SYSTEM SALES, AND HAVE A ROBUST ECONOMIC CASE. HAS DEF**
7 **PERFORMED AN ECONOMIC ANALYSIS OF THE CCE PROJECTS?**

8 A. Yes. DEF performed a cost-effectiveness analysis for the CCE Projects. The
9 results of it is presented in DEF witness Borsch's Exhibit BMHB-5. The analysis was
10 conducted in 2022 and utilized EnCompass® along with spreadsheet analysis with
11 respect to estimated capital costs. DEF provided copies of the EnCompass® input and
12 output files in response to OPC POD No. 37 and provided the spreadsheets in response
13 to LULAC/FR POD No. 2. I have reviewed these files.

14 DEF used a 20-year study period ending in 2041 and compared a case with the
15 CCE Projects added to one that instead principally added a 190 MW combustion
16 turbine generation facility in 2029 and a 100 MW battery storage facility in 2033.¹⁸ In
17 the analysis, DEF forecasts a 20-year CPVRR net benefit of \$392.827 million, which
18 consists of forecasted gross CPVRR savings of \$505.570 million less a forecasted gross
19 CPVRR cost of \$112.743 million.¹⁹ This yields a forecasted 20-year benefit to cost
20 ratio of 4.48, which is very robust. The net benefit is derived approximately 58% from
21 avoided fixed generation costs, approximately 30% from reduced fuel and purchased

¹⁸ DEF Response to LULAC/FR POD No. 2 at Projects tab of '2024 Rate Case CC HR Upgrade Study CPVRR Results.xlsx'.

¹⁹ Borsch Exhibit BMHB-5.

1 power costs, and approximately 12% from other avoided variable generation costs.²⁰
2 Note that while DEF assumed a carbon emission cost in its EnCompass® runs and
3 forecasted a significant carbon emission savings from the CCE Projects based on that
4 cost, DEF has excluded that forecasted amount of savings from its reported forecasted
5 gross savings of \$505.570 million and reported a forecasted net benefit of \$392.827
6 million. This is appropriate given there is currently no existing or pending carbon
7 emission tax or cap and trade legislation in Florida or at the federal level. Finally, it
8 should be noted that DEF had negligible off-system sales in both its CCE Projects case
9 and its alternative case. So, the forecasted savings DEF's analysis shows comes from
10 providing service to DEF's customers, not off-system sales.

11

12 **Q. DID DEF PROVIDE A CPVRR BREAKEVEN CALCULATION IN ITS**
13 **ANALYSIS?**

14 A. It did not. However, from DEF's spreadsheet files, which included its detailed
15 EnCompass® production cost results, I was able to perform those calculations, which
16 are presented in Exhibit JRD-9. Specifically, the results of DEF's cost effectiveness
17 analysis forecast that the CCE Projects will break even on a CPVRR basis in the second
18 year of the 20-year study period, which is not surprising given the very high forecasted
19 20-year CPVRR benefit to cost ratio of 4.48.

²⁰ Borsch Exhibit BMHB-5.

1 **Q. DID DEF PERFORM ANY SENSITIVITY CASES?**

2 A. It did with respect to different possible variations of the CCE Projects it
3 ultimately pursued, but it did not perform any fuel cost or project cost sensitivities.

4

5 **Q. IN YOUR OPINION, WOULD A FUEL COST SENSITIVITY CASE BE**
6 **WARRANTED FOR THE CCE PROJECT ANALYSIS?**

7 A. No. The 2022 vintage natural gas and coal prices used by DEF for its CCE
8 Projects cost effectiveness analysis are lower than those for its 2023 TYSP and using
9 higher fuel prices that the one used by DEF would simply yield a greater forecasted net
10 benefit from the proposed CCE Projects.

11

12 **Q. HAVE THERE BEEN CHANGES TO THE CCE PROJECTS SINCE THEY**
13 **WERE STUDIED IN 2022?**

14 A. Yes. There have been modifications to the Hines PB 4 Project such that it is
15 now expected to increase the output of Hines PB4 by 80 MW rather than 52 MW.²¹ In
16 addition, the projected heat rate reductions have increased for the Citrus PB 1, Citrus
17 PB 2 and Hines PB 4 CCE Projects.²² Finally, the estimated capital cost of the CCE
18 projects has increased from \$124.9 million to \$154.9 million.²³

²¹ Comparing Anderson Exhibit RDA-3 to DEF Response to LULAC/FR POD No. 2 at Assumptions tab of '2024 Rate Case CC Heat Rate Upgrade Study CPVRR analysis.xlsx' and Confidential Deposition of Anderson, May 24, 2024 at response to Late-Filed Deposition Exhibit No. 3.

²² Comparing Anderson Exhibit RDA-3 to DEF Response to LULAC/FR POD No. 2 at Assumptions tab of '2024 Rate Case CC Heat Rate Upgrade Study CPVRR analysis.xlsx'.

²³ Comparing Anderson Exhibit RDA-3 to DEF Response to LULAC/FR POD No. 2 at CC_Capital_RR tab of '2024 Rate Case CC Heat Rate Upgrade Study CPVRR analysis.xlsx'.

1 **Q. WHAT WOULD BE THE IMPLICATION OF THE GREATER OUTPUT**
2 **INCREASE FOR HINES PB 4 AND THE INCREASED HEAT RATE**
3 **REDUCTIONS?**

4 A. Both of these would increase the forecasted gross savings from the CCE
5 Projects versus that forecast by DEF.

6
7 **Q. ARE ALL OF DEF'S COMBINED CYCLE GENERATION FACILITIES**
8 **CURRENTLY EXPECTED TO RETIRE BY THE END OF THE 20-YEAR**
9 **STUDY PERIOD IN 2041?**

10 A. No. For example, the Citrus combined cycle units are assumed to be operational
11 through at least 2058 in DEF's cost effectiveness analysis.

12
13 **Q. HAVE YOU EXAMINED THE IMPACT IT WOULD HAVE ON THE**
14 **ECONOMICS OF THE CCE PROJECTS IF THE LATEST CAPITAL COST**
15 **ESTIMATE FOR THE PROJECTS WAS USED AND THE COMBINED**
16 **CYCLE UNITS WERE CONSERVATIVELY ASSUMED TO ALL RETIRE BY**
17 **THE END OF 2041?**

18 A. Yes, I have roughly estimated that impact as a conservative stress test and
19 present it in Exhibit JRD-10. To roughly estimate the impact, I scaled the annual
20 revenue requirement for the original capital cost for the CCE Projects by the ratio of
21 \$154.9 million to \$124.9 million. Then I added an end effect in 2041 to recover in
22 2041 the remaining capital cost of CCE Projects that would have been collected from
23 2042 through 2058. Even under this conservative stress test, the economics for the

1 CCE Projects are still very robust with a 20-year CPVRR benefit to cost ratio of 3.27
2 and a CPVRR breakeven in the 3rd year of the 20-year study period.

3

4 **Q. WHAT IS YOUR CONCLUSION WITH RESPECT TO THE CCE PROJECTS?**

5 A. While the CCE Projects are elective rather than mandatory in nature, they are
6 consistent with providing reliable electric service at lowest reasonable cost because
7 their economic justification is based on serving DEF's customers and the projected net
8 economic benefit from the CCE projects is very robust. Therefore, based on my
9 analysis and what I am aware of as the filing date of this testimony, I cannot say that
10 DEF's decision to pursue to CCE Projects was imprudent or unreasonable.

11

12 **IV. FORECASTED ECONOMIC**

13

14 **PERFORMANCE OF 2025-2027 SOLAR PROJECTS**

15 **Q.**

16 **LIKE WITH THE CCE PROJECTS, YOU HAVE CONCLUDED THE 2025-**
17 **2027 SOLAR PROJECTS WITH THEIR PROJECTED IN-SERVICE DATES**
18 **ARE NOT NECESSARY FOR RELIABILITY AT THIS TIME AND**
19 **THEREFORE MUST BE SHOWN TO BE FOR THE PURPOSE OF SERVING**
20 **DEF'S CUSTOMERS, RATHER THAN OFF-SYSTEM SALES, AND HAVE A**
21 **ROBUST ECONOMIC CASE. HAS DEF PERFORMED AN ECONOMIC**
22 **ANALYSIS OF THE 2025-2027 SOLAR PROJECTS?**

23 A.

24 Yes. As with the CCE Projects, DEF performed a cost-effectiveness analysis
for the 2025-2027 Solar Projects. The results of this analysis with all 14 of the 2025-
2027 Solar Projects pursued, is presented in DEF witness Borsch's Exhibit BMHB-3-
Amended. In addition, the results of the analysis with only the first five of the fourteen

1 2025-2027 Solar Projects being pursued is presented in DEF witness Borsch's Exhibit
2 BMHB-4-Amended.

3

4 **Q. WHY DID DEF PERFORM A VERSION OF THE ANALYSIS WITH ONLY**
5 **FIVE OF THE PROJECTS PURSUED?**

6 A. DEF is proposing to pursue the first five of the fourteen 2025-2027 Solar
7 Projects as an expansion of its Clean Energy Connection ("CEC") voluntary
8 community solar program rather than as normal DEF generation projects. DEF witness
9 Borsch in his direct testimony presents the analysis of the five projects alone to show
10 they are cost-effective.²⁴ However, DEF has indicated, and I have confirmed from my
11 review of DEF's Encompass® input and output files provided in response to OPC's
12 Fourth Request for Production, No. 37 and the relevant spreadsheet files provided in
13 response to LULAC/FR First Request for Production, No. 2, that there is no difference
14 in how the five projects proposed to be an expansion of the DEF CEC program are
15 modeled in the cost-effectiveness analysis versus the other nine of the fourteen 2025-
16 2027 Solar Projects.²⁵ As a result, the analysis presented by DEF in DEF witness
17 Borsch's Exhibit BMHB-4-Amended does not present any information with respect to
18 the benefit of expanding DEF's CEC program. Rather, it indicates DEF's forecasted
19 cost-effectiveness of pursuing the five projects alone as normal DEF generation
20 projects.

²⁴ Borsch Direct at 18-20.

²⁵ Confidential Video-Teleconference Deposition of Borsch, May 30, 2024, Transcript Volume II at 106:24 through 108:12.

1 **Q. HAVE YOU MADE ANY EVALUATION OF THE REASONABLENESS OF**
2 **DEF’S PROPOSAL TO EXPAND ITS CEC PROGRAM?**

3 A. No, that goes beyond the scope of my analysis and direct testimony in this
4 proceeding. I have not examined the issue and as a result have not developed an
5 opinion on that question for this testimony.

6

7 **Q. WAS THE COST EFFECTIVENESS ANALYSIS THAT DEF PERFORMED**
8 **FOR THE 2025-2027 SOLAR PROJECTS PERFORMED IN THE SAME**
9 **MANNER AS DEF’S COST EFFECTIVENESS ANALYSIS FOR ITS CCE**
10 **PROJECTS?**

11 A. It was generally performed in the same manner, but there are some important
12 differences. Specifically, it was different in the following respects:

- 13 • The analysis was performed in 2023 using DEF’s 2023 TYSP assumption including
14 its 2023 TYSP base case fuel price assumptions.²⁶
- 15 • DEF used a study period that ends in 2057, rather than 2041, based on the last of
16 2025-2027 Solar Projects entering service in 2027 and an assumed design life for
17 the projects of 30 years.²⁷
- 18 • The principal assumed alternative resources for the 2025-2027 Solar projects
19 consisted of a 190 MW combustion turbine generation facility added in 2030 and a
20 four-hour 50 MW battery added in 2032.²⁸
- 21 • DEF included PTCs for the projects under the Inflation Reduction Act (“IRA”)
22 assuming it could fully realize 90% of their value in 2025, 2026, and 2027 and
23 100% of their value thereafter.²⁹

²⁶ Borsch Direct at 10 and 18 and DEF’s response to OPC ROG No. 74.

²⁷ Borsch Direct at 17; DEF 2023 and 2024 TYSPs at Schedule 9; Confidential Deposition of Goff, May 29, 2024, p. 91, lines 4-5; DEF Response to LULAC/FR DOD No. 2 at Solar14_RR tab of ‘2024 Rate Case Solar Study_14_Solar.xlsx’.

²⁸ DEF Response to LULAC/FR POD No. 2 at Projects tab of ‘2024 Rate Case Solar Study CPVRR Results.xlsx’.

²⁹ Panizza Direct at 9 and DEF Response to LULAC/FR POD No. 2 at PTC tab of ‘2024 Rate Case Solar Study_14_Solar.xlsx’.

- 1 • DEF assumed no cost for carbon emissions.

2

3 **Q. WHAT WERE THE RESULTS OF DEF'S COST EFFECTIVENESS**
4 **ANALYSIS?**

5 A. As detailed in DEF witness Borsch's Exhibit BMHB-3-Amended, if all 14 of
6 the 2025-2027 Solar Projects are pursued as proposed by DEF, DEF forecasts a
7 CPVRR net benefit of approximately \$552 million, which consists of gross CPVRR
8 savings of approximately \$2.478 billion less gross CPVRR costs of approximately
9 \$1.925 billion. This amounts to a forecasted 35-year CPVRR benefit-to-cost ratio of
10 approximately 1.29. The gross CPVRR savings is driven approximately 20.1% by
11 avoided fixed generation and transmission costs, approximately 25% by forecasted
12 realized PTCs from the projects, approximately 48.0% by reduced fuel cost and
13 approximately 6.7% by other reduced variable generation costs.³⁰

14 If only the first five of the fourteen 2025-2027 Solar Projects are pursued, as
15 detailed in DEF witness Borsch's Exhibit BMHB-4-Amended, DEF forecasts a
16 CPVRR net benefit of approximately \$313 million, which consists of gross CPVRR
17 savings of approximately \$1.029 billion less gross CPVRR costs of approximately
18 \$716 million. This amounts to a forecasted CPVRR benefit to cost ratio of
19 approximately 1.44. The gross CPVRR savings is driven approximately 28.0% by
20 avoided fixed generation and transmission costs, approximately 21.9% by forecasted
21 realized PTCs from the projects, approximately 44.3% by reduced fuel costs and
22 approximately 5.8% by reductions in other variable generation costs.³¹

³⁰ Borsch Exhibit BMHB-3-Amended.

³¹ Borsch's Exhibit BMHB-3-Amended.

1 **Q. DID DEF IN ITS COST-EFFECTIVENESS ANALYSIS REVIEW OTHER**
2 **COMBINATIONS OF SOLAR PROJECTS FOR 2025-2027 BESIDES PURSUIT**
3 **OF ALL 14 PROJECTS OR JUST THE FIRST FIVE?**

4 A. No. However, it is possible to estimate the incremental economic benefit of the
5 last nine projects from the difference between the DEF results for pursuing all 14 of
6 the projects versus the DEF results for just pursuing the first five projects.

7
8 **Q. HAVE YOU DONE SO?**

9 A. Yes, I have done so in Exhibit JRD-11. As can be seen from Exhibit JRD-11,
10 the last nine projects incrementally only have a forecasted CPVRR net benefit of
11 approximately \$240 million, which consists of gross CPVRR savings of approximately
12 \$1.449 billion less gross CPVRR costs of approximately \$1.209 billion. This amounts
13 to a forecasted benefit to cost ratio of approximately 1.20, significantly less than the
14 1.44 for the first five of the 14 projects. The gross CPVRR savings are driven
15 approximately 14.6% by avoided fixed generation and transmission costs,
16 approximately 27.3% by forecasted realized PTCs from the projects, approximately
17 50.6% by reduced fuel costs and by approximately 7.4% by reductions in other variable
18 generation costs. What is noteworthy is that the contribution from avoided fixed
19 generation and transmission costs is only 14.6% for the last nine projects versus 28.0%
20 for the first five projects. This may be driven by a lower summer firm capacity
21 percentage for the latest of the 2025-2027 Solar Projects versus the earliest of the 2025-
22 2027 Solar Projects.

1 **Q. DOES THIS DECLINING BENEFIT-TO-COST RATIO PERFORMANCE**
2 **GIVE YOU A CONCERN?**

3 A. Yes. These results suggest the last two to three of the 2025-2027 Solar Projects
4 may not have a robust economic case for them. For example, in the table below, I apply
5 the average results for the first five projects and last nine projects linearly to provide a
6 rough ballpark estimate of how the benefit-to-cost ratio for the individual projects may
7 decline for new projects as they are added.

TABLE JRD-4

Rough Ballpark Estimate of Potential B to C Ratio Decline 2025-2027 Solar Projects

<u>Project #</u>	<u>Potential B to C Ratio</u>
1	1.51
2	1.47
3	1.44
4	1.41
5	1.37
6	1.34
7	1.30
8	1.27
9	1.23
10	1.20
11	1.17
12	1.13
13	1.10
14	1.06

8 While the actual behavior may not be linear as shown above, the above table is
9 illustrative with respect to showing that the last couple of 2025-2027 solar projects may
10 not have robust economics particularly since they may have the lowest summer firm
11 capacity percentage.

1 **Q. HOW CAN THIS ISSUE BE RESOLVED?**

2 A. It can be resolved by performing a cost-effectiveness analysis for the last two
3 of the fourteen 2025-2027 Solar Projects with the previous twelve already added. OPC
4 has in discovery requested DEF to perform that analysis.

5
6 **Q. DID DEF PERFORM A CPVRR BREAKEVEN CALCULATION FOR THE**
7 **2025-2027 SOLAR PROJECTS?**

8 A. No. However, from the spreadsheets for DEF's cost-effectiveness analysis
9 provided in response to LULAC/FR POD No. 2, I was able to perform the calculations
10 for pursuit of all 14 of the projects. This is presented in my Exhibit JRD-12. I found
11 that DEF's cost-effectiveness analysis forecasts a CPVRR breakeven for pursuit of all
12 14 of the 2025-2027 Solar Project by the tenth year of 35-year study period. This is
13 less than halfway through the assumed 30-year design life of the projects and within
14 ten years of the last of the projects entering service.

15
16 **Q. HAVE THERE BEEN CHANGES TO THE PROJECTS SINCE THEY WERE**
17 **STUDIED IN 2023 THAT WOULD MATERIALLY AFFECT THE RESULTS**
18 **OF DEF'S COST EFFECTIVENESS ANALYSIS?**

19 A. Yes. The estimated total projected cost of the 2025-2027 Solar Projects has
20 increased from approximately \$1.604 billion to approximately \$1.663 billion.³²

³² Confidential DEF Response to OPC ROG No. 186 at 20240025-OPCROG7-00018141.

1 **Q. CAN THE IMPACT OF THE ABOVE ON DEF'S COST EFFECTIVENESS**
2 **ANALYSIS BE ROUGHLY ESTIMATED?**

3 A. Yes. I have done so in Exhibit JRD-9 for the pursuit of all 14 projects by scaling
4 the annual revenue requirement for the generation and transmission capital
5 expenditures for the projects by the ratio of 1.663 to 1.604 (1.037:1). The results of
6 Exhibit JRD-13 forecast, under DEF's cost estimate for the projects at the time of the
7 filing of this testimony, a CPVRR net benefit of \$487 million consisting of gross
8 CPVRR savings of \$2.477 billion less gross CPVRR costs of \$1,991 billion. This
9 provides a forecasted benefit to cost ratio of 1.24 for the projects over the 35-year study
10 period. The results also show a forecasted CPVRR breakeven in the 11th year of the
11 35-year study period, which is within 10 years of the last of the projects entering
12 service.

13
14 **Q. DID DEF PERFORM ANY FUEL COST SENSITIVITIES IN ITS COST**
15 **EFFECTIVENESS ANALYSIS FOR THE 2025-2027 SOLAR PROJECTS?**

16 A. It did not. It indicates it did not because, based on its examination its of its 2023
17 TYSP base, high and low fuel scenarios, it would not produce materially different
18 results.³³

19
20 **Q. DO YOU AGREE?**

21 A. Yes. I performed a very rough estimate of the potential impact of using DEF's
22 low fuel forecast scenario and found it only slightly affected the forecasted benefit to

³³ DEF Response to OPC ROG No. 74.

1 cost ratio of 2025-2027 Solar Projects, by dropping it from 1.24 to 1.23. I performed
2 the very rough estimate by scaling total annual coal and natural gas costs from DEF's
3 EnCompass® production cost runs for the cost effectiveness analysis by the ratio the
4 low case to base case 2023 TYSP coal and natural gas prices. This rough estimate,
5 which included the now higher estimated capital cost of the projects, is provided in
6 Exhibit JRD-14.

7

8 **Q. WHAT IS YOUR CONCLUSION WITH RESPECT TO THE 2025-2027 SOLAR**
9 **PROJECTS?**

10 A. At the time of the filing of this direct testimony, I am concerned there is not a
11 robust economic case for the last two of the fourteen 2025-2027 Solar Projects, and this
12 weakness is dragging the overall economics of the fourteen 2025-2027 Solar Projects
13 down near below robust economic territory especially when updated capital cost
14 estimates are applied. Given this, I cannot at this time conclude DEF's decision to
15 pursue the last two of the fourteen 2025-2027 Solar Projects was prudent and
16 reasonable. I reserve the right to file supplemental testimony if DEF completes the
17 additional cost effectiveness analysis, including CPVRR benefit to cost ratio and break
18 even calculations, that OPC has requested once I have reviewed those results with
19 respect to the question of whether DEF's decision to pursue the last two projects was
20 not imprudent or unreasonable.

21 With respect to the first twelve of the fourteen 2025-2027 Solar Projects, while
22 they are elective rather than mandatory, they are consistent with providing reliable
23 electric service at lowest reasonable cost because their economic justification is based

1 on serving DEF's customers and the projected net economic benefit from them is
2 robust. Therefore, based on my analysis, and what I am aware of at the time of filing
3 this testimony, I cannot say that DEF's decision to pursue the first twelve of the
4 fourteen 2025-2027 Solar Projects was imprudent or unreasonable.

5

6

7

**V. FORECASTED ECONOMIC
PERFORMANCE OF POWERLINE BATTERY PROJECT**

8 **Q. LIKE WITH THE CCE PROJECTS AND THE 2025-2027 SOLAR PROJECTS,**
9 **YOU HAVE CONCLUDED THE POWERLINE BATTERY PROJECT WITH**
10 **ITS PROJECTED IN-SERVICE DATE IS NOT NECESSARY FOR**
11 **RELIABILITY AT THIS TIME AND THEREFORE MUST BE SHOWN TO BE**
12 **FOR THE PURPOSE OF SERVING DEF'S CUSTOMERS, RATHER THAN**
13 **OFF-SYSTEM SALES, AND HAVE A ROBUST ECONOMIC CASE. HAS DEF**
14 **PERFORMED ON ECONOMIC ANALYSIS OF THE POWERLINE**
15 **BATTERY PROJECT?**

16 **A.** Yes. As with the CCE Projects and the 2025-2027 Solar Projects, DEF
17 performed a cost-effectiveness analysis of the proposed Powerline Battery Project. The
18 results of this analysis are presented in DEF witness Borsch's Exhibit BMHB-6-
19 Amended. The analysis was performed with and without an extra 10% ITC for the
20 project being located in an Energy Community as defined under the IRA.

1 **Q. WAS THE COST-EFFECTIVENESS ANALYSIS THAT DEF PERFORMED**
2 **FOR THE POWERLINE BATTERY PROJECT PERFORMED IN THE SAME**
3 **MANNER AS THAT FOR THE 2025-2027 SOLAR PROJECTS?**

4 A. In general it was, but there are a few differences. First, the Powerline Battery
5 Project only has an assumed design life of 15 years such that the total study period is
6 only 19 years. Second, ITCs under the IRA are modeled rather than PTCs since
7 batteries are not eligible for PTCs. Third, the alternative DEF analyzed was a 50 MW
8 four-hour battery added in 2030 and another 50 MW four-hour battery added in 2031.³⁴
9 Finally, DEF in Exhibit BMHB-6-Amended lumped the capital cost of the Powerline
10 Battery Project into the change of other generation and transmission capital costs.
11 While the Powerline Battery Project cost is still separately derivable from Exhibit
12 BMHB-6-Amended, it is inconsistent with DEF's presentation in Exhibit BMHB-3-
13 Amended, Exhibit BMHB-4-Amended and Exhibit BMHB-5.

14
15 **Q. WHAT DOES DEF'S POWERLINE BATTERY PROJECT COST-**
16 **EFFECTIVENESS ANALYSIS INDICATE?**

17 A. As detailed in DEF witness Borsch's Exhibit BMHB-6-Amended, it indicates
18 that without the extra 10% ITC, the Powerline Battery Project would have a forecasted
19 CPVRR net cost of \$5.04 million rather than a forecast CPVRR benefit. With the
20 additional 10% ITC, Exhibit BMHB-6-Amended forecasts a CPVRR net benefit of
21 approximately \$3.88 million, which consists of gross CPVRR saving of approximately
22 \$143.93 million less gross CPVRR costs of \$140.06 million. This amounts to a

³⁴ DEF Response to LULAC/FR POD No. 2 at Projects tab of '2024 Rate Case Battery Study CPVRR Results.xlsx'.

1 CPVRR benefit to cost ratio of only 1.03. Note there is no forecasted fuel cost savings.
2 The gross CPVRR savings is being driven approximately 95.6% by avoided fixed
3 generation at transmission costs and 4.3% by variable generation costs unrelated to
4 fuel.

5
6 **Q. DID DEF PERFORM A CPVRR BREAKEVEN CALCULATION FOR THE**
7 **POWERLINE BATTERY PROJECT?**

8 A. No. However, from the spreadsheets for DEF's cost-effectiveness analysis
9 provided in response to LULAC/FR POD No. 2, I was able to perform the calculations
10 for Powerline Battery Project. This is presented in my Exhibit JRD-15. I found that
11 even with the additional 10% ITC, DEF's cost effectiveness analysis does not forecast
12 a CPVRR breakeven for the Powerline Battery Project until the 18th year of the 19 year
13 study period – the second to last year of the assumed design life of the battery and well
14 after ten years from when the battery would enter service.

15
16 **Q. GIVEN THESE RESULTS, WHAT DO YOU CONCLUDE WITH RESPECT**
17 **TO THE POWERLINE BATTERY PROJECT?**

18 A. The Powerline Battery Project is not needed for reliability at this time and it
19 does not have a robust forecasted CPVRR net benefit. Also, even the forecasted 1.03
20 CPVRR benefit to cost ratio with the additional 10% ITC is likely overstated as DEF
21 has problematically assumed the same firm capacity percentage from nameplate for
22 two-hour battery as it has for four-hour batteries. Given all this, pursuit of the
23 Powerline Battery Project at this time is not prudent or reasonable because its pursuit

1 at this time is not consistent with providing reliable electric service at lowest reasonable
2 cost. Its costs should be entirely removed from DEF's projected test years in this
3 proceeding.

4

5 **Q. DEF WITNESS BORSCH IN HIS DIRECT TESTIMONY SUGGESTS THE**
6 **ECONOMIC SHORTFALL FOR THE POWERLINE BATTERY PROJECT**
7 **MIGHT BE OVERCOME BY THE PROJECT ALLOWING THE**
8 **AVOIDANCE OF SOLAR GENERATION OUTPUT CURTAILMENT FOR**
9 **SOME HOURS NOT WELL-REPRESENTED IN THE ENCOMPASS®**
10 **MODELING. HE INDICATES THIS AVOIDED SOLAR GENERATION**
11 **OUTPUT CURTAILMENT MIGHT AMOUNT TO AS MUCH AS 30 HOURS**
12 **PER YEAR AT THE RATED CAPABILITY OF THE BATTERY OVER THE**
13 **LIFE OF THE BATTERY.³⁵ HOW DO YOU RESPOND?**

14 **A.** It is a highly speculative argument and should be rejected by the Commission.
15 The EnCompass® model already captures the dollar benefit of avoided solar generation
16 output curtailments at the hourly level of granularity. While it is possible for there to
17 be some solar generation output curtailment avoidance that is not captured by the
18 EnCompass® model particularly at the sub-hourly level, there is no evidence it would
19 amount to anything near 30 hours per year at the rated capability of the battery over the
20 life of the battery.

³⁵ Borsch Direct at 23-24.

1 **Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?**

2 A. Yes, it does.

Qualifications of James R. Dauphinais

1 **Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.**

2 A. James R. Dauphinais. My business address is 16690 Swingley Ridge Road,
3 Suite 140, Chesterfield, MO 63017, USA.

4
5 **Q. PLEASE STATE YOUR OCCUPATION.**

6 A. I am a consultant in the field of public utility regulation and a Managing
7 Principal with the firm of Brubaker & Associates, Inc. (“BAI”), energy, economic and
8 regulatory consultants.

9
10 **Q. PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND**
11 **EXPERIENCE.**

12 A. I graduated from Hartford State Technical College in 1983 with an Associate's
13 Degree in Electrical Engineering Technology. Subsequent to graduation, I was
14 employed by the Transmission Planning Department of the Northeast Utilities Service
15 Company¹ as an Engineering Technician.

16 While employed as an Engineering Technician, I completed undergraduate
17 studies at the University of Hartford. I graduated in 1990 with a Bachelor's Degree in
18 Electrical Engineering. Subsequent to graduation, I was promoted to the position of
19 Associate Engineer. Between 1993 and 1994, I completed graduate level courses in the
20 study of power system analysis, power system transients and power system protection

¹ In 2015, Northeast Utilities changed its name to Eversource Energy.

1 through the Engineering Outreach Program of the University of Idaho. By 1996 I had
2 been promoted to the position of Senior Engineer.

3 In the employment of the Northeast Utilities Service Company, I was
4 responsible for conducting thermal, voltage and stability analyses of the Northeast
5 Utilities' transmission system to support planning and operating decisions. This
6 involved the use of load flow, power system stability and production cost computer
7 simulations. It also involved examination of potential solutions to operational and
8 planning problems including, but not limited to, transmission line solutions and the
9 routes that might be utilized by such transmission line solutions. Among the most
10 notable achievements I had in this area include the solution of a transient stability
11 problem near Millstone Nuclear Power Station, and the solution of a small signal (or
12 dynamic) stability problem near Seabrook Nuclear Power Station. In 1993 I was
13 awarded the Chairman's Award, Northeast Utilities' highest employee award, for my
14 work involving stability analysis in the vicinity of Millstone Nuclear Power Station.

15 From 1990 to 1996, I represented Northeast Utilities on the New England Power
16 Pool Stability Task Force. I also represented Northeast Utilities on several other
17 technical working groups within the New England Power Pool ("NEPOOL") and the
18 Northeast Power Coordinating Council ("NPCC"), including the 1992-1996 New York-
19 New England Transmission Working Group, the Southeastern Massachusetts/Rhode
20 Island Transmission Working Group, the NPCC CPSS-2 Working Group on Extreme
21 Disturbances and the NPCC SS-38 Working Group on Interarea Dynamic Analysis.
22 This latter working group also included participation from a number of ECAR, PJM and
23 VACAR utilities.

1 From 1990 to 1995, I also acted as an internal consultant to the Nuclear
2 Electrical Engineering Department of Northeast Utilities. This included interactions
3 with the electrical engineering personnel of the Connecticut Yankee, Millstone and
4 Seabrook nuclear generation stations and inspectors from the Nuclear Regulatory
5 Commission (“NRC”).

6 In addition to my technical responsibilities, from 1995 to 1997, I was also
7 responsible for oversight of the day-to-day administration of Northeast Utilities' Open
8 Access Transmission Tariff. This included the creation of Northeast Utilities' pre-FERC
9 Order No. 889 transmission electronic bulletin board and the coordination of Northeast
10 Utilities' transmission tariff filings prior to and after the issuance of Federal Energy
11 Regulatory Commission (“FERC” or “Commission”) FERC Order No. 888. I was also
12 responsible for spearheading the implementation of Northeast Utilities' Open Access
13 Same-Time Information System and Northeast Utilities’ Standard of Conduct under
14 FERC Order No. 889. During this time, I represented Northeast Utilities on the Federal
15 Energy Regulatory Commission's "What" Working Group on Real-Time Information
16 Networks. Later I served as Vice Chairman of the NEPOOL OASIS Working Group
17 and Co-Chair of the Joint Transmission Services Information Network Functional
18 Process Committee. I also served for a brief time on the Electric Power Research
19 Institute facilitated "How" Working Group on OASIS and the North American Electric
20 Reliability Council facilitated Commercial Practices Working Group.

21 In 1997 I joined the firm of Brubaker & Associates, Inc. The firm includes
22 consultants with backgrounds in accounting, engineering, economics, mathematics,
23 computer science and business. Since my employment with the firm, I have filed or

1 presented testimony before the Federal Energy Regulatory Commission in Consumers
2 Energy Company, Docket No. OA96-77-000; Midwest Independent Transmission
3 System Operator, Inc., Docket No. ER98-1438-000; Montana Power Company, Docket
4 No. ER98-2382-000; Inquiry Concerning the Commission's Policy on Independent
5 System Operators, Docket No. PL98-5-003; SkyGen Energy LLC v. Southern Company
6 Services, Inc., Docket No. EL00-77-000; Alliance Companies, et al., Docket
7 No. EL02-65-000, et al.; Entergy Services, Inc., Docket No. ER01-2201-000;
8 Remediating Undue Discrimination through Open Access Transmission Service,
9 Standard Electricity Market Design, Docket No. RM01-12-000; Midwest Independent
10 Transmission System Operator, Inc., Docket No. ER10-1791-000; NorthWestern
11 Corporation, Docket No. ER10-1138-001, et al.; Illinois Industrial Energy Consumers
12 v. Midcontinent Independent System Operator, Inc., Docket No. EL15-82-000;
13 Midcontinent Independent System Operator, Inc., Docket No. ER16-833-000;
14 Midcontinent Independent System Operator, Inc., Docket No. ER17-284-000; and
15 Midcontinent Independent System Operator, Inc. and Ameren Services Company
16 Docket No. ER18-463-000. I have also filed or presented testimony before the Alberta
17 Utilities Commission, the California Public Utilities Commission, the Colorado Public
18 Utilities Commission, the Connecticut Department of Public Utility Control, the Florida
19 Public Service Commission, the Idaho Public Service Commission, the Illinois
20 Commerce Commission, the Indiana Utility Regulatory Commission, the Iowa Utilities
21 Board, the Kentucky Public Service Commission, the Louisiana Public Service
22 Commission, the Michigan Public Service Commission, the Missouri Public Service
23 Commission, the Montana Public Service Commission, the Nevada Public Utilities

1 Commission, the New Mexico Public Regulation Commission, the Council of the City
2 of New Orleans, the Oklahoma Corporation Commission, the Public Utility
3 Commission of Texas, the Virginia State Corporation Commission, the Wisconsin
4 Public Service Commission, the Wyoming Public Service Commission, Federal District
5 Court and various committees of the Illinois, Missouri and South Carolina state
6 legislatures. This testimony has been given regarding a wide variety of issues including,
7 but not limited to, ancillary service rates, avoided cost calculations, certification of
8 public convenience and necessity, class cost of service, cost allocation, fuel adjustment
9 clauses, fuel costs, generation interconnection, interruptible rates, market power, market
10 structure, off-system sales, prudence, purchased power costs, resource adequacy,
11 resource planning, rate design, retail open access, standby rates, transmission losses,
12 transmission planning, transmission rates and transmission line routing.

13 I have also participated on behalf of clients in the Southwest Power Pool
14 Congestion Management System Working Group, the Alliance Market Development
15 Advisory Group and several committees and working groups of the Midcontinent
16 Independent System Operator, Inc. (“MISO”), including the Congestion Management
17 Working Group; Economic Planning Users Group; Loss of Load Expectation Working
18 Group; Market Subcommittee; Michigan Transmission Studies Task Force; Planning
19 Subcommittee; Regional Expansion, Criteria and Benefits Working Group; Resource
20 Adequacy Subcommittee (formerly the Supply Adequacy Working Group); and
21 Reliability Subcommittee. I am currently a member of the MISO Advisory Committee
22 in the end-use customer sector on behalf of industrial customer groups in Illinois,

1 Louisiana, Michigan and Texas. I am also the past Chairman of the Issues/Solutions
2 Subgroup of the MISO Revenue Sufficiency Guarantee (“RSG”) Task Force.

3 In 2009, I completed the University of Wisconsin-Madison High Voltage Direct
4 Current (“HVDC”) Transmission course for Planners that was sponsored by MISO. I
5 am a member of the Power and Energy Society (“PES”) of the Institute of Electrical and
6 Electronics Engineers (“IEEE”).

7 In addition to our main office in St. Louis, the firm also has branch offices in
8 Corpus Christi, Texas; Louisville, Kentucky; and Phoenix, Arizona.

DUKE ENERGY FLORIDA
DOCKET NO. 20240025-EI
6/8/2024
 2023 TYSP FORECAST OF CAPACITY AND DEMAND
 AT TIME OF SUMMER PEAK
 EXAMINATION OF TIMING OF NEED FOR FIRM CAPACITY ADDITIONS

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
YEAR	SYSTEM FIRM SUMMER PEAK DEMAND MW	RESERVE MARGIN BEFORE REMOVING RESOURCES ADDITIONS MW	% OF PEAK	PROPOSED ^a CCE PROJECTS MW	PROPOSED ^b 2025-2027 SOLAR MW	PROPOSED ^c POWERLINE BATTERY MW	LATER PLANNED ADDITIONS MW	RESERVE MARGIN AFTER REMOVING ADDITIONS MW	% OF PEAK	20% RESERVE MARGIN SHORTFALL MW	PLANNED CT RETIREMENTS MW	SHORTFALL W/ 3-YEAR RET. DELAY MW	SHORTFALL WITH RD + CCE ADDED MW	SHORTFALL WITH RD + CCE + SOLAR ADDED MW
2023	8,270	3,574	43%	0	0	0	0	3,574	43%	0	0	0	0	0
2024	8,899	2,473	28%	0	0	0	0	2,473	28%	0	0	0	0	0
2025	8,728	3,139	36%	187	37	0	0	2,915	33%	0	0	0	0	0
2026	8,814	2,883	33%	296	112	0	0	2,475	28%	0	-171	0	0	0
2027	8,868	2,024	23%	348	187	90	0	1,399	16%	375	-480	0	0	0
2028	8,932	2,000	22%	348	239	90	0	1,323	15%	464	-524	0	0	0
2029	9,019	1,946	22%	348	239	90	37	1,231	14%	573	-524	220	0	0
2030	9,128	1,879	21%	348	239	90	84	1,117	12%	708	-524	664	316	77
2031	9,205	1,852	20%	348	239	90	140	1,034	11%	807	-524	807	459	219
2032	9,366	1,886	20%	348	239	90	206	1,002	11%	871	-524	871	523	284

Notes:

- a. Without deductions for DEF's alternative of a 190 MW CT in 2029 and two 4-Hour 50 MW Batteries in 2033.
- b. Without deductions for DEF's alternative of a 190 MW CT in 2030 and a 4-hour 50 MW Battery in 2032.
- c. Without deductions for DEF's alternative of 50 MW 4-Hour Battery in 2030 and 50 MW 4-Hour Battery in 2031.

Sources: Duke Energy Florida 2023 Ten Year Site Plan, April 3, 2023, Schedules 7.1 and 8
 Duke Energy Florida Response to LULAC/FR POD No. 2 at Projects tab of 2024 Rate Case CC HR Upgrade Study CPVRR Results.xlsx, 2024 Rate Case Solar Study CPVRR Results.xlsx and 2024 Rate Case Battery Study CPVRR Results.xlsx

PLEASE NOTE THE INFORMATION IN THIS FILING IS NON-CONFIDENTIAL OR REDACTED

DUKE ENERGY FLORIDA
DOCKET NO. 20240025-EI
6/8/2024
 2023 TYSP FORECAST OF CAPACITY AND DEMAND
 AT TIME OF WINTER PEAK
 EXAMINATION OF TIMING OF NEED FOR FIRM CAPACITY ADDITIONS

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
YEAR	SYSTEM FIRM WINTER PEAK DEMAND	RESERVE MARGIN BEFORE REMOVING RESOURCES ADDITIONS	RESERVE MARGIN BEFORE REMOVING RESOURCES ADDITIONS	PROPOSED ^a CCE PROJECTS	PROPOSED ^b 2025-2027 SOLAR	PROPOSED ^c POWERLINE BATTERY	LATER PLANNED ADDITIONS	RESERVE MARGIN AFTER REMOVING ADDITIONS	RESERVE MARGIN AFTER REMOVING ADDITIONS	RESERVE MARGIN 20% SHORTFALL	PLANNED CT RETIREMENTS	SHORTFALL W/ 3-YEAR RET. DELAY	SHORTFALL WITH RD + CCE ADDED	SHORTFALL WITH RD + CCE + SOLAR ADDED
	MW	MW	% OF PEAK	MW	MW	MW	MW	MW	% OF PEAK	MW	MW	MW	MW	MW
2022/23	8,204	4,155	51%	0	0	0	0	4,155	51%	0	0	0	0	0
2023/24	9,163	3,081	34%	0	0	0	0	3,081	34%	0	0	0	0	0
2024/25	8,954	3,074	34%	100	0	0	0	2,974	33%	0	0	0	0	0
2025/26	8,979	2,828	31%	187	0	0	0	2,641	29%	0	-226	0	0	0
2026/27	9,004	2,980	33%	296	0	0	0	2,684	30%	0	-226	0	0	0
2027/28	8,427	2,465	29%	348	0	90	0	2,027	24%	0	-669	0	0	0
2028/29	8,494	2,398	28%	348	0	90	0	1,960	23%	0	-669	0	0	0
2029/30	8,583	2,376	28%	348	0	90	0	1,938	23%	0	-669	0	0	0
2030/31	8,639	2,388	28%	348	0	90	67	1,883	22%	0	-669	0	0	0
2031/32	8,766	2,327	27%	348	0	90	135	1,754	20%	0	-669	0	0	0

Notes:

- a. Without deductions for DEF's alternative of a 190 MW CT in 2029 and two 4-Hour 50 MW Batteries in 2033.
- b. Without deductions for DEF's alternative of a 190 MW CT in 2030 and a 4-hour 50 MW Battery in 2032.
- c. Without deductions for DEF's alternative of 50 MW 4-Hour Battery in 2030 and 50 MW 4-Hour Battery in 2031.

Sources: Duke Energy Florida 2023 Ten Year Site Plan, April 3, 2023, Schedules 7.2 and 8
 Duke Energy Florida Response to LULAC/FR POD No. 2 at Projects tab of 2024 Rate Case CC HR Upgrade Study CPVRR Results.xlsx, 2024 Rate Case Solar Study CPVRR Results.xlsx and 2024 Rate Case Battery Study CPVRR Results.xlsx

DUKE ENERGY FLORIDA
DOCKET NO. 20240025-EI
6/8/2024
 2024 TYSP FORECAST OF CAPACITY AND DEMAND
 AT TIME OF SUMMER PEAK
 EXAMINATION OF TIMING OF NEED FOR FIRM CAPACITY ADDITIONS

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
YEAR	SYSTEM FIRM SUMMER PEAK DEMAND MW	RESERVE MARGIN BEFORE REMOVING RESOURCES MW	RESERVE MARGIN ADDITIONS % OF PEAK	PROPOSED ^a CCE PROJECTS MW	PROPOSED ^b 2025-2027 SOLAR MW	PROPOSED ^c POWERLINE BATTERY MW	LATER PLANNED ADDITIONS MW	RESERVE MARGIN AFTER REMOVING ADDITIONS MW	% OF PEAK	RESERVE MARGIN SHORTFALL MW	PLANNED CT RETIREMENTS MW	SHORTFALL W/ 3-YEAR RET. DELAY MW	SHORTFALL WITH RD + CCE ADDED MW	SHORTFALL WITH RD + CCE + SOLAR ADDED MW
2024	9,000	2,369	26%	0	0	0	0	2,369	26%	0	0	0	0	0
2025	8,836	2,603	29%	206	19	0	0	2,379	27%	0	0	0	0	0
2026	8,790	3,184	36%	389	75	0	0	2,720	31%	0	0	0	0	0
2027	8,781	2,257	26%	389	169	90	0	1,609	18%	147	-460	0	0	0
2028	8,908	2,247	25%	389	262	90	0	1,506	17%	276	-460	0	0	0
2029	9,093	2,149	24%	389	262	90	85	1,323	15%	496	-460	36	0	0
2030	9,260	2,076	22%	389	262	90	177	1,158	12%	695	-460	695	306	43
2031	9,374	2,016	22%	389	262	90	277	998	11%	877	-460	877	488	226
2032	9,595	2,279	24%	389	262	90	337	1,200	13%	719	-460	719	330	67
2033	9,811	2,545	26%	389	262	90	397	1,407	14%	556	-460	556	167	0

Notes:

- a. Without deductions for DEF's alternative of a 190 MW CT in 2029 and two 4-Hour 50 MW Batteries in 2033.
- b. Without deductions for DEF's alternative of a 190 MW CT in 2030 and a 4-hour 50 MW Battery in 2032.
- c. Without deductions for DEF's alternative of 50 MW 4-Hour Battery in 2030 and 50 MW 4-Hour Battery in 2031.

Sources: Duke Energy Florida 2024 Ten Year Site Plan, Revised April 22, 2024, Schedules 7.1 and 8
 Duke Energy Florida Response to LULAC/FR POD No. 2 at Projects tab of 2024 Rate Case CC HR Upgrade Study CPVRR Results.xlsx, 2024 Rate Case Solar Study CPVRR Results.xlsx and 2024 Rate Case Battery Study CPVRR Results.xlsx

DUKE ENERGY FLORIDA
DOCKET NO. 20240025-EI
6/8/2024
 2024 TYSP FORECAST OF CAPACITY AND DEMAND
 AT TIME OF WINTER PEAK
 EXAMINATION OF TIMING OF NEED FOR FIRM CAPACITY ADDITIONS

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
YEAR	SYSTEM FIRM WINTER PEAK DEMAND MW	RESERVE MARGIN BEFORE REMOVING RESOURCES MW	RESERVE MARGIN ADDITIONS % OF PEAK	PROPOSED ^a CCE PROJECTS MW	PROPOSED ^b 2025-2027 SOLAR MW	PROPOSED ^c POWERLINE BATTERY MW	LATER PLANNED ADDITIONS MW	RESERVE MARGIN AFTER REMOVING ADDITIONS MW	% OF PEAK	RESERVE MARGIN SHORTFALL MW	PLANNED CT RETIREMENTS MW	SHORTFALL W/ 3-YEAR RET. DELAY MW	SHORTFALL WITH RD + CCE ADDED MW	SHORTFALL WITH RD + CCE + SOLAR ADDED MW
2023/24	8,872	3,323	37%	0	0	0	0	3,323	37%	0	0	0	0	0
2024/25	9,112	2,465	27%	99	0	0	0	2,366	26%	0	0	0	0	0
2025/26	9,124	2,847	31%	216	0	0	0	2,631	29%	0	0	0	0	0
2026/27	9,165	2,739	30%	347	0	0	0	2,392	26%	0	-198	0	0	0
2027/28	8,682	2,220	26%	347	0	90	0	1,783	21%	0	-591	0	0	0
2028/29	8,795	2,179	25%	347	0	90	72	1,670	19%	89	-591	0	0	0
2029/30	8,957	2,089	23%	347	0	90	144	1,508	17%	284	-591	0	0	0
2030/31	9,017	2,100	23%	347	0	90	216	1,447	16%	356	-591	356	9	9
2031/32	9,125	1,993	22%	347	0	90	216	1,340	15%	485	-591	485	138	138
2032/33	9,210	2,377	26%	347	0	90	682	1,258	14%	584	-591	584	237	237

Notes:

- a. Without deductions for DEF's alternative of a 190 MW CT in 2029 and two 4-Hour 50 MW Batteries in 2033.
- b. Without deductions for DEF's alternative of a 190 MW CT in 2030 and a 4-hour 50 MW Battery in 2032.
- c. Without deductions for DEF's alternative of 50 MW 4-Hour Battery in 2030 and 50 MW 4-Hour Battery in 2031.

Sources: Duke Energy Florida 2024 Ten Year Site Plan, Revised April 22, 2024, Schedules 7.2 and 8
 Duke Energy Florida Response to LULAC/FR POD No. 2 at Projects tab of 2024 Rate Case CC HR Upgrade Study CPVRR Results.xlsx, 2024 Rate Case Solar Study CPVRR Results.xlsx and 2024 Rate Case Battery Study CPVRR Results.xlsx

DEF Firm Capacity Need Timing for Summer Peak - 2023 TYSP -

Bayboro P1-P4 CT Retirement Sensitivity

DUKE ENERGY FLORIDA
DOCKET NO. 20240025-EI
6/8/2024

2023 TYSP FORECAST OF CAPACITY AND DEMAND
AT TIME OF SUMMER PEAK
EXAMINATION OF TIMING OF NEED FOR FIRM CAPACITY ADDITIONS
BAYBORO P1-P4 CT RETIREMENT SENSITIVITY

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	SYSTEM FIRM SUMMER PEAK DEMAND	RESERVE MARGIN BEFORE REMOVING RESOURCES ADDITIONS	% OF PEAK	PROPOSED ^a CCE PROJECTS	PROPOSED ^b 2025-2027 SOLAR	PROPOSED ^c POWERLINE BATTERY	LATER PLANNED ADDITIONS	RESERVE MARGIN AFTER REMOVING ADDITIONS	% OF PEAK	20% RESERVE MARGIN SHORTFALL	PLANNED NON-BB CT RETIREMENTS	SHORTFALL W/ 3-YEAR RET. DELAY	SHORTFALL WITH RD + CCE ADDED	SHORTFALL WITH RD + CCE + SOLAR ADDED
YEAR	MW	MW		MW	MW	MW	MW	MW		MW	MW	MW	MW	MW
2023	8,270	3,574	43%	0	0	0	0	3,574	43%	0	0	0	0	0
2024	8,899	2,473	28%	0	0	0	0	2,473	28%	0	0	0	0	0
2025	8,728	3,139	36%	187	37	0	0	2,915	33%	0	0	0	0	0
2026	8,814	2,883	33%	296	112	0	0	2,475	28%	0	0	0	0	0
2027	8,868	2,024	23%	348	187	90	0	1,399	16%	375	-309	66	0	0
2028	8,932	2,000	22%	348	239	90	0	1,323	15%	464	-353	111	0	0
2029	9,019	1,946	22%	348	239	90	37	1,231	14%	573	-353	220	0	0
2030	9,128	1,879	21%	348	239	90	84	1,117	12%	708	-353	664	316	77
2031	9,205	1,852	20%	348	239	90	140	1,034	11%	807	-353	807	459	219
2032	9,366	1,886	20%	348	239	90	206	1,002	11%	871	-353	871	523	284

Notes:

- a. Without deductions for DEF's alternative of a 190 MW CT in 2029 and two 4-Hour 50 MW Batteries in 2033.
- b. Without deductions for DEF's alternative of a 190 MW CT in 2030 and a 4-hour 50 MW Battery in 2032.
- c. Without deductions for DEF's alternative of 50 MW 4-Hour Battery in 2030 and 50 MW 4-Hour Battery in 2031.

Sources: Duke Energy Florida 2023 Ten Year Site Plan, April 3, 2023, Schedules 7.1 and 8
Duke Energy Florida Response to LULAC/FR POD No. 2 at Projects tab of 2024 Rate Case CC HR Upgrade Study CPVRR Results.xlsx, 2024 Rate Case Solar Study CPVRR Results.xlsx and 2024 Rate Case Battery Study CPVRR Results.xlsx

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Docket No. 20240025-EI
 DEF Firm Capacity Need Timing for Winter Peak - 2023 TYSP -
 Bayboro P1-P4 CT Retirement Sensitivity
 Exhibit JRD-6, Page 1 of 1

DUKE ENERGY FLORIDA
DOCKET NO. 20240025-EI
6/8/2024
 2023 TYSP FORECAST OF CAPACITY AND DEMAND
 AT TIME OF WINTER PEAK
 EXAMINATION OF TIMING OF NEED FOR FIRM CAPACITY ADDITIONS
 BAYBORO P1-P4 CT RETIREMENT SENSITIVITY

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	SYSTEM FIRM WINTER PEAK DEMAND	RESERVE MARGIN BEFORE REMOVING RESOURCES ADDITIONS	RESERVE MARGIN BEFORE REMOVING RESOURCES ADDITIONS	PROPOSED ^a CCE PROJECTS	PROPOSED ^b 2025-2027 SOLAR	PROPOSED ^c POWERLINE BATTERY	LATER PLANNED ADDITIONS	RESERVE MARGIN AFTER REMOVING ADDITIONS	RESERVE MARGIN AFTER REMOVING ADDITIONS	RESERVE MARGIN 20% SHORTFALL	PLANNED NON-BB CT RETIREMENTS	SHORTFALL W/ 3-YEAR RET. DELAY	SHORTFALL WITH RD + CCE ADDED	SHORTFALL WITH RD + CCE + SOLAR ADDED
YEAR	MW	MW	% OF PEAK	MW	MW	MW	MW	MW	% OF PEAK	MW	MW	MW	MW	MW
2022/23	8,204	4,155	51%	0	0	0	0	4,155	51%	0	0	0	0	0
2023/24	9,163	3,081	34%	0	0	0	0	3,081	34%	0	0	0	0	0
2024/25	8,954	3,074	34%	100	0	0	0	2,974	33%	0	0	0	0	0
2025/26	8,979	2,828	31%	187	0	0	0	2,641	29%	0	0	0	0	0
2026/27	9,004	2,980	33%	296	0	0	0	2,684	30%	0	0	0	0	0
2027/28	8,427	2,465	29%	348	0	90	0	2,027	24%	0	-443	0	0	0
2028/29	8,494	2,398	28%	348	0	90	0	1,960	23%	0	-443	0	0	0
2029/30	8,583	2,376	28%	348	0	90	0	1,938	23%	0	-443	0	0	0
2030/31	8,639	2,388	28%	348	0	90	67	1,883	22%	0	-443	0	0	0
2031/32	8,766	2,327	27%	348	0	90	135	1,754	20%	0	-443	0	0	0

Notes:

- a. Without deductions for DEF's alternative of a 190 MW CT in 2029 and two 4-Hour 50 MW Batteries in 2033.
- b. Without deductions for DEF's alternative of a 190 MW CT in 2030 and a 4-hour 50 MW Battery in 2032.
- c. Without deductions for DEF's alternative of 50 MW 4-Hour Battery in 2030 and 50 MW 4-Hour Battery in 2031.

Sources: Duke Energy Florida 2023 Ten Year Site Plan, April 3, 2023, Schedules 7.2 and 8
 Duke Energy Florida Response to LULAC/FR POD No. 2 at Projects tab of 2024 Rate Case CC HR Upgrade Study CPVRR Results.xlsx, 2024 Rate Case Solar Study CPVRR Results.xlsx and 2024 Rate Case Battery Study CPVRR Results.xlsx

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DEF Firm Capacity Need Timing for Summer Peak - 2024 TYSP -

Bayboro P1-P4 CT Retirement Sensitivity

Exhibit JRD-7, Page 1 of 1

DUKE ENERGY FLORIDA
DOCKET NO. 20240025-EI
6/8/2024

2024 TYSP FORECAST OF CAPACITY AND DEMAND
AT TIME OF SUMMER PEAK
EXAMINATION OF TIMING OF NEED FOR FIRM CAPACITY ADDITIONS
BAYBORO P1-P4 CT RETIREMENT SENSITIVITY

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
YEAR	SYSTEM FIRM SUMMER PEAK DEMAND MW	RESERVE MARGIN BEFORE REMOVING RESOURCES ADDITIONS MW	% OF PEAK	PROPOSED ^a CCE PROJECTS MW	PROPOSED ^b 2025-2027 SOLAR MW	PROPOSED ^c POWERLINE BATTERY MW	LATER PLANNED ADDITIONS MW	RESERVE MARGIN AFTER REMOVING ADDITIONS MW	% OF PEAK	20% RESERVE MARGIN SHORTFALL MW	PLANNED NON-BB CT RETIREMENTS MW	SHORTFALL W/ 3-YEAR RET. DELAY MW	SHORTFALL WITH RD + CCE ADDED MW	SHORTFALL WITH RD + CCE + SOLAR ADDED MW
2024	9,000	2,369	26%	0	0	0	0	2,369	26%	0	0	0	0	0
2025	8,836	2,603	29%	206	19	0	0	2,379	27%	0	0	0	0	0
2026	8,790	3,184	36%	389	75	0	0	2,720	31%	0	0	0	0	0
2027	8,781	2,257	26%	389	169	90	0	1,609	18%	147	-309	0	0	0
2028	8,908	2,247	25%	389	262	90	0	1,506	17%	276	-309	0	0	0
2029	9,093	2,149	24%	389	262	90	85	1,323	15%	496	-309	187	0	0
2030	9,260	2,076	22%	389	262	90	177	1,158	12%	695	-309	695	306	43
2031	9,374	2,016	22%	389	262	90	277	998	11%	877	-309	877	488	226
2032	9,595	2,279	24%	389	262	90	337	1,200	13%	719	-309	719	330	67
2033	9,811	2,545	26%	389	262	90	397	1,407	14%	556	-309	556	167	0

Notes:

- a. Without deductions for DEF's alternative of a 190 MW CT in 2029 and two 4-Hour 50 MW Batteries in 2033.
- b. Without deductions for DEF's alternative of a 190 MW CT in 2030 and a 4-hour 50 MW Battery in 2032.
- c. Without deductions for DEF's alternative of 50 MW 4-Hour Battery in 2030 and 50 MW 4-Hour Battery in 2031.

Sources: Duke Energy Florida 2024 Ten Year Site Plan, Revised April 22, 2024, Schedules 7.1 and 8
Duke Energy Florida Response to LULAC/FR POD No. 2 at Projects tab of 2024 Rate Case CC HR Upgrade Study CPVRR Results.xlsx, 2024 Rate Case Solar Study CPVRR Results.xlsx and 2024 Rate Case Battery Study CPVRR Results.xlsx

PLEASE NOTE THE INFORMATION IN THIS FILING IS NON-CONFIDENTIAL OR REDACTED

Docket No. 20240025-EI
 DEF Firm Capacity Need Timing for Winter Peak - 2024 TYSP -
 Bayboro P1-P4 CT Retirement Sensitivity
 Exhibit JRD-8, Page 1 of 1

DUKE ENERGY FLORIDA
DOCKET NO. 20240025-EI
6/8/2024
 2024 TYSP FORECAST OF CAPACITY AND DEMAND
 AT TIME OF WINTER PEAK
 EXAMINATION OF TIMING OF NEED FOR FIRM CAPACITY ADDITIONS
 BAYBORO P1-P4 CT RETIREMENT SENSITIVITY

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	
YEAR	SYSTEM FIRM WINTER PEAK DEMAND	RESERVE MARGIN BEFORE REMOVING RESOURCES ADDITIONS	RESERVE MARGIN BEFORE REMOVING RESOURCES ADDITIONS	PROPOSED ^a CCE PROJECTS	PROPOSED ^b 2025-2027 SOLAR	PROPOSED ^c POWERLINE BATTERY	LATER PLANNED ADDITIONS	RESERVE MARGIN AFTER REMOVING ADDITIONS	RESERVE MARGIN AFTER REMOVING ADDITIONS	RESERVE MARGIN AFTER REMOVING ADDITIONS	20% RESERVE MARGIN SHORTFALL	PLANNED NON-BB CT RETIREMENTS	SHORTFALL W/ 3-YEAR RET. DELAY	SHORTFALL WITH RD + CCE ADDED	SHORTFALL WITH RD + CCE + SOLAR ADDED
	MW	MW	% OF PEAK	MW	MW	MW	MW	MW	% OF PEAK	MW	MW	MW	MW	MW	MW
2023/24	8,872	3,323	37%	0	0	0	0	3,323	37%	0	0	0	0	0	0
2024/25	9,112	2,465	27%	99	0	0	0	2,366	26%	0	0	0	0	0	0
2025/26	9,124	2,847	31%	216	0	0	0	2,631	29%	0	0	0	0	0	0
2026/27	9,165	2,739	30%	347	0	0	0	2,392	26%	0	0	0	0	0	0
2027/28	8,682	2,220	26%	347	0	90	0	1,783	21%	0	-393	0	0	0	0
2028/29	8,795	2,179	25%	347	0	90	72	1,670	19%	89	-393	0	0	0	0
2029/30	8,957	2,089	23%	347	0	90	144	1,508	17%	284	-393	0	0	0	0
2030/31	9,017	2,100	23%	347	0	90	216	1,447	16%	356	-393	356	9	9	0
2031/32	9,125	1,993	22%	347	0	90	216	1,340	15%	485	-393	485	138	138	138
2032/33	9,210	2,377	26%	347	0	90	682	1,258	14%	584	-393	584	237	237	237

Notes:

- a. Without deductions for DEF's alternative of a 190 MW CT in 2029 and two 4-Hour 50 MW Batteries in 2033.
- b. Without deductions for DEF's alternative of a 190 MW CT in 2030 and a 4-hour 50 MW Battery in 2032.
- c. Without deductions for DEF's alternative of 50 MW 4-Hour Battery in 2030 and 50 MW 4-Hour Battery in 2031.

Sources: Duke Energy Florida 2024 Ten Year Site Plan, Revised April 22, 2024, Schedules 7.2 and 8
 Duke Energy Florida Response to LULAC/FR POD No. 2 at Projects tab of 2024 Rate Case CC HR Upgrade Study CPVRR Results.xlsx, 2024 Rate Case Solar Study CPVRR Results.xlsx and 2024 Rate Case Battery Study CPVRR Results.xlsx

PLEASE NOTE THE INFORMATION IN THIS FILING IS NON-CONFIDENTIAL OR REDACTED

DUKE ENERGY FLORIDA
DOCKET NO. 20240025-EI
6/8/2024

DEF Cost Effectiveness Analysis
CCE Projects
Breakeven
(\$2022 Millions)

<u>Year</u> (1)	<u>Study</u> <u>Year</u> (2)	<u>CPVRR</u> <u>Gross</u> <u>Benefit</u> (3)	<u>CPVRR</u> <u>Gross</u> <u>Cost</u> (4)	<u>CPVRR</u> <u>Net</u> <u>Benefit</u> (5)	<u>CPVRR</u> <u>Benefit</u> <u>to</u> <u>Cost</u> <u>Ratio</u> (6)
2022	1	\$0.000	\$0.000	\$0.000	N/A
2023	2	\$0.575	\$0.548	\$0.027	1.05
2024	3	\$3.214	\$1.406	\$1.808	2.29
2025	4	\$13.998	\$6.942	\$7.056	2.02
2026	5	\$30.071	\$15.926	\$14.144	1.89
2027	6	\$48.907	\$25.807	\$23.101	1.90
2028	7	\$67.034	\$36.216	\$30.818	1.85
2029	8	\$91.507	\$46.602	\$44.904	1.96
2030	9	\$118.901	\$56.001	\$62.900	2.12
2031	10	\$143.702	\$64.501	\$79.201	2.23
2032	11	\$167.548	\$72.183	\$95.365	2.32
2033	12	\$202.736	\$79.120	\$123.616	2.56
2034	13	\$252.083	\$85.377	\$166.706	2.95
2035	14	\$296.133	\$90.789	\$205.344	3.26
2036	15	\$337.120	\$95.510	\$241.610	3.53
2037	16	\$369.893	\$99.756	\$270.137	3.71
2038	17	\$409.715	\$103.566	\$306.149	3.96
2039	18	\$437.777	\$106.978	\$330.799	4.09
2040	19	\$469.853	\$110.026	\$359.827	4.27
2041	20	\$505.571	\$112.743	\$392.827	4.48

Source: DEF response to LULAC/FR POD No. 2 at '2024 Rate Case - CC Heat Rate Upgrade Study CPVRR analysis.xlsx' and '2024 Rate Case CC HR Upgrade Study CPVRR Results'.

DUKE ENERGY FLORIDA
DOCKET NO. 20240025-EI
6/8/2024

DEF Cost Effectiveness Analysis

CCE Projects

Breakeven

OPC Estimate

Updated Capital Costs + Hypothetical Retirement of All CC Units at End of 2041
(\$2022 Millions)

<u>Year</u> (1)	<u>Study Year</u> (2)	<u>CPVRR Gross Benefit</u> (3)	<u>CPVRR Gross Cost</u> (4)	<u>CPVRR Net Benefit</u> (5)	<u>CPVRR Benefit to Cost Ratio</u> (6)
2022	1	\$0.000	\$0.000	\$0.000	N/A
2023	2	\$0.575	\$0.680	(\$0.105)	0.85
2024	3	\$3.214	\$1.744	\$1.470	1.84
2025	4	\$13.998	\$8.609	\$5.388	1.63
2026	5	\$30.071	\$19.752	\$10.319	1.52
2027	6	\$48.907	\$32.005	\$16.902	1.53
2028	7	\$67.034	\$44.915	\$22.119	1.49
2029	8	\$91.507	\$57.796	\$33.711	1.58
2030	9	\$118.901	\$69.452	\$49.449	1.71
2031	10	\$143.702	\$79.993	\$63.708	1.80
2032	11	\$167.548	\$89.521	\$78.027	1.87
2033	12	\$202.736	\$98.124	\$104.612	2.07
2034	13	\$252.083	\$105.884	\$146.200	2.38
2035	14	\$296.133	\$112.596	\$183.537	2.63
2036	15	\$337.120	\$118.451	\$218.669	2.85
2037	16	\$369.893	\$123.716	\$246.176	2.99
2038	17	\$409.715	\$128.441	\$281.274	3.19
2039	18	\$437.777	\$132.673	\$305.104	3.30
2040	19	\$469.853	\$136.454	\$333.400	3.44
2041	20	\$505.571	\$154.430	\$351.141	3.27

Source: DEF response to LULAC/FR POD No. 2 at '2024 Rate Case - CC Heat Rate Upgrade Study CPVRR analysis.xlsx' and '2024 Rate Case CC HR Upgrade Study CPVRR Results'.

DUKE ENERGY FLORIDA
DOCKET NO. 20240025-EI
6/8/2024

DEF Cost Effectiveness Analysis
2025-2027 Solar Projects
OPC Estimate for Last Nine Projects
CPVRR
(\$2023 Millions)

	First <u>5 Projects</u> (1)	All <u>14 Projects</u> (2)	Estimate Last <u>9 Projects</u> (3)
Fuel Cost	456	1,189	733
Environmental Costs	1	1	0
Variable Costs	59	166	107
PTC	(1)	0	1
Inc Transmission and FOM Cost	61	110	49
Inc Gen Capital	227	390	163
	<hr/> 803	<hr/> 1,856	<hr/> 1,053
Transm and FOM Add Solar	(97)	(265)	(168)
Gen Capital Add Solar	(619)	(1,660)	(1,041)
	<hr/> (716)	<hr/> (1,925)	<hr/> (1,209)
PTC Add Solar	<hr/> 225	<hr/> 621	<hr/> 396
Add Solar Savings	312	552	240
B to C Ratio	1.44	1.29	1.20

Source:

DEF Exhibits BMHB-3-Amended and
BHMB-4-Amended

DUKE ENERGY FLORIDA
DOCKET NO. 20240025-EI
6/8/2024

DEF Cost Effectiveness Analysis
2025-2027 Solar Projects (All 14 Pursued)
Breakeven
(\$2023 Millions)

<u>Year</u> (1)	<u>Study</u> <u>Year</u> (2)	<u>CPVRR</u> <u>Gross</u> <u>Benefit</u> (3)	<u>CPVRR</u> <u>Gross</u> <u>Cost</u> (4)	<u>CPVRR</u> <u>Net</u> <u>Benefit</u> (5)	<u>CPVRR</u> <u>Benefit</u> <u>to</u> <u>Cost</u> <u>Ratio</u> (6)
2023	1	\$ (0)	\$ 2	\$ (2)	N/A
2024	2	\$ (0)	\$ 16	\$ (16)	0.00
2025	3	\$ 21	\$ 80	\$ (59)	0.26
2026	4	\$ 110	\$ 206	\$ (97)	0.53
2027	5	\$ 235	\$ 362	\$ (127)	0.65
2028	6	\$ 397	\$ 514	\$ (117)	0.77
2029	7	\$ 538	\$ 649	\$ (111)	0.83
2030	8	\$ 678	\$ 770	\$ (92)	0.88
2031	9	\$ 812	\$ 880	\$ (68)	0.92
2032	10	\$ 980	\$ 980	\$ 0	1.00
2033	11	\$1,136	\$ 1,071	\$ 65	1.06
2034	12	\$1,274	\$ 1,154	\$ 120	1.10
2035	13	\$1,400	\$ 1,230	\$ 170	1.14
2036	14	\$1,497	\$ 1,300	\$ 197	1.15
2037	15	\$1,576	\$ 1,363	\$ 213	1.16
2038	16	\$1,640	\$ 1,425	\$ 215	1.15
2039	17	\$1,703	\$ 1,482	\$ 222	1.15
2040	18	\$1,762	\$ 1,533	\$ 229	1.15
2041	19	\$1,818	\$ 1,579	\$ 238	1.15
2042	20	\$1,867	\$ 1,622	\$ 246	1.15
2043	21	\$1,925	\$ 1,660	\$ 265	1.16
2044	22	\$1,980	\$ 1,695	\$ 285	1.17
2045	23	\$2,024	\$ 1,726	\$ 298	1.17
2046	24	\$2,065	\$ 1,755	\$ 310	1.18
2047	25	\$2,098	\$ 1,780	\$ 318	1.18
2048	26	\$2,122	\$ 1,804	\$ 318	1.18
2049	27	\$2,160	\$ 1,825	\$ 334	1.18
2050	28	\$2,232	\$ 1,845	\$ 388	1.21
2051	29	\$2,281	\$ 1,862	\$ 419	1.22
2052	30	\$2,337	\$ 1,878	\$ 459	1.24
2053	31	\$2,383	\$ 1,893	\$ 490	1.26
2054	32	\$2,425	\$ 1,906	\$ 519	1.27
2055	33	\$2,457	\$ 1,918	\$ 539	1.28
2056	34	\$2,476	\$ 1,923	\$ 553	1.29
2057	35	\$2,477	\$ 1,925	\$ 552	1.29

Sources: DEF response to LULAC/FR POD No. 2 at '2024 Rate Case Solar Study_14_Solar.xlsx' and '2024 Rate Case Solar Study CPVRR Results.xlsx'.

DUKE ENERGY FLORIDA
DOCKET NO. 20240025-EI
6/8/2024

DEF Cost Effectiveness Analysis
2025-2027 Solar Projects (All 14 Pursued)
Breakeven
OPC Estimate
Updated Capital Costs
(\$2023 Millions)

<u>Year</u>	<u>Study</u>	<u>CPVRR</u>	<u>CPVRR</u>	<u>CPVRR</u>	<u>CPVRR</u>
<u>(1)</u>	<u>(2)</u>	<u>Gross</u>	<u>Gross</u>	<u>Net</u>	<u>to</u>
		<u>Benefit</u>	<u>Cost</u>	<u>Benefit</u>	<u>Cost</u>
		<u>(3)</u>	<u>(4)</u>	<u>(5)</u>	<u>Ratio</u>
					<u>(6)</u>
2023	1	\$ (0)	\$ 2	\$ (2)	N/A
2024	2	\$ (0)	\$ 16	\$ (16)	0.00
2025	3	\$ 21	\$ 83	\$ (62)	0.25
2026	4	\$ 110	\$ 214	\$ (104)	0.51
2027	5	\$ 235	\$ 375	\$ (140)	0.63
2028	6	\$ 397	\$ 532	\$ (135)	0.75
2029	7	\$ 538	\$ 672	\$ (134)	0.80
2030	8	\$ 678	\$ 797	\$ (119)	0.85
2031	9	\$ 812	\$ 911	\$ (99)	0.89
2032	10	\$ 980	\$ 1,014	\$ (34)	0.97
2033	11	\$ 1,136	\$ 1,108	\$ 27	1.02
2034	12	\$ 1,274	\$ 1,194	\$ 80	1.07
2035	13	\$ 1,400	\$ 1,273	\$ 127	1.10
2036	14	\$ 1,497	\$ 1,345	\$ 152	1.11
2037	15	\$ 1,576	\$ 1,411	\$ 166	1.12
2038	16	\$ 1,640	\$ 1,475	\$ 166	1.11
2039	17	\$ 1,703	\$ 1,533	\$ 170	1.11
2040	18	\$ 1,762	\$ 1,586	\$ 176	1.11
2041	19	\$ 1,818	\$ 1,634	\$ 184	1.11
2042	20	\$ 1,867	\$ 1,678	\$ 190	1.11
2043	21	\$ 1,925	\$ 1,717	\$ 208	1.12
2044	22	\$ 1,980	\$ 1,753	\$ 227	1.13
2045	23	\$ 2,024	\$ 1,785	\$ 238	1.13
2046	24	\$ 2,065	\$ 1,815	\$ 250	1.14
2047	25	\$ 2,098	\$ 1,842	\$ 256	1.14
2048	26	\$ 2,122	\$ 1,866	\$ 256	1.14
2049	27	\$ 2,160	\$ 1,888	\$ 272	1.14
2050	28	\$ 2,232	\$ 1,908	\$ 324	1.17
2051	29	\$ 2,281	\$ 1,926	\$ 355	1.18
2052	30	\$ 2,337	\$ 1,943	\$ 395	1.20
2053	31	\$ 2,383	\$ 1,958	\$ 426	1.22
2054	32	\$ 2,425	\$ 1,971	\$ 454	1.23
2055	33	\$ 2,457	\$ 1,983	\$ 474	1.24
2056	34	\$ 2,476	\$ 1,989	\$ 487	1.25
2057	35	\$ 2,477	\$ 1,991	\$ 487	1.24

Source: DEF response to LULAC/FR POD No. 2 at '2024 Rate Case Solar Study_14_Solar.xlsx' and '2024 Rate Case Solar Study CPVRR Results.xlsx'.

DUKE ENERGY FLORIDA

DOCKET NO. 20240025-EI

6/8/2024

DEF Cost Effectiveness Analysis
2025-2027 Solar Projects (All 14 Pursued)

Breakeven

OPC Estimate

Updated Capital Costs + 2023 TYSP Low Case Fuel Prices
(\$2023 Millions)

<u>Year</u> (1)	<u>Study</u> <u>Year</u> (2)	<u>CPVRR</u> <u>Gross</u> <u>Benefit</u> (3)	<u>CPVRR</u> <u>Gross</u> <u>Cost</u> (4)	<u>CPVRR</u> <u>Net</u> <u>Benefit</u> (5)	<u>CPVRR</u> <u>Benefit</u> <u>to</u> <u>Cost</u> <u>Ratio</u> (6)
2023	1	\$ (0)	\$ 2	\$ (2)	N/A
2024	2	\$ (0)	\$ 16	\$ (16)	0.00
2025	3	\$ 20	\$ 83	\$ (62)	0.25
2026	4	\$ 104	\$ 214	\$ (109)	0.49
2027	5	\$ 220	\$ 375	\$ (155)	0.59
2028	6	\$ 376	\$ 532	\$ (156)	0.71
2029	7	\$ 512	\$ 672	\$ (160)	0.76
2030	8	\$ 653	\$ 797	\$ (145)	0.82
2031	9	\$ 788	\$ 911	\$ (123)	0.87
2032	10	\$ 959	\$ 1,014	\$ (55)	0.95
2033	11	\$ 1,117	\$ 1,108	\$ 9	1.01
2034	12	\$ 1,259	\$ 1,194	\$ 65	1.05
2035	13	\$ 1,388	\$ 1,273	\$ 115	1.09
2036	14	\$ 1,488	\$ 1,345	\$ 143	1.11
2037	15	\$ 1,570	\$ 1,411	\$ 159	1.11
2038	16	\$ 1,635	\$ 1,475	\$ 160	1.11
2039	17	\$ 1,699	\$ 1,533	\$ 166	1.11
2040	18	\$ 1,757	\$ 1,586	\$ 171	1.11
2041	19	\$ 1,811	\$ 1,634	\$ 177	1.11
2042	20	\$ 1,858	\$ 1,678	\$ 180	1.11
2043	21	\$ 1,913	\$ 1,717	\$ 195	1.11
2044	22	\$ 1,964	\$ 1,753	\$ 211	1.12
2045	23	\$ 2,003	\$ 1,785	\$ 218	1.12
2046	24	\$ 2,040	\$ 1,815	\$ 225	1.12
2047	25	\$ 2,068	\$ 1,842	\$ 226	1.12
2048	26	\$ 2,088	\$ 1,866	\$ 222	1.12
2049	27	\$ 2,121	\$ 1,888	\$ 233	1.12
2050	28	\$ 2,194	\$ 1,908	\$ 286	1.15
2051	29	\$ 2,242	\$ 1,926	\$ 316	1.16
2052	30	\$ 2,299	\$ 1,943	\$ 356	1.18
2053	31	\$ 2,345	\$ 1,958	\$ 387	1.20
2054	32	\$ 2,387	\$ 1,971	\$ 415	1.21
2055	33	\$ 2,418	\$ 1,983	\$ 435	1.22
2056	34	\$ 2,437	\$ 1,989	\$ 449	1.23
2057	35	\$ 2,439	\$ 1,991	\$ 448	1.23

Source: DEF response to LULAC/FR POD No. 2 at '2024 Rate Case Solar Study_14_Solar.xlsx' and '2024 Rate Case Solar Study CPVRR Results.xlsx'.

DEF Response to OPC POD No. 34 at 2024-0025-OPCPOD4-00018097 through 00018098.

DUKE ENERGY FLORIDA
DOCKET NO. 20240025-EI
6/8/2024

DEF Cost Effectiveness Analysis
Powerline Battery Project (40% ITC with no Haircut)
Breakeven
(\$2023 Millions)

<u>Year</u> (1)	<u>Study</u> <u>Year</u> (2)	<u>CPVRR</u> <u>Gross</u> <u>Benefit</u> (3)	<u>CPVRR</u> <u>Gross</u> <u>Cost</u> (4)	<u>CPVRR</u> <u>Net</u> <u>Benefit</u> (5)	<u>CPVRR</u> <u>Benefit</u> <u>to</u> <u>Cost</u> <u>Ratio</u> (6)
2023	1	\$ 0.46	\$ 0.11	\$ 0.35	N/A
2024	2	\$ 0.46	\$ 0.11	\$ 0.35	N/A
2025	3	\$ 0.46	\$ 0.11	\$ 0.35	N/A
2026	4	\$ 0.32	\$ (0.17)	\$ 0.49	N/A
2027	5	\$ 1.68	\$ 17.34	\$ (15.65)	0.10
2028	6	\$ 3.00	\$ 32.02	\$ (29.02)	0.09
2029	7	\$ 4.78	\$ 44.68	\$ (39.91)	0.11
2030	8	\$ 16.76	\$ 57.01	\$ (40.26)	0.29
2031	9	\$ 35.63	\$ 68.29	\$ (32.67)	0.52
2032	10	\$ 52.50	\$ 78.91	\$ (26.41)	0.67
2033	11	\$ 67.68	\$ 88.93	\$ (21.25)	0.76
2034	12	\$ 81.31	\$ 97.86	\$ (16.55)	0.83
2035	13	\$ 93.41	\$ 105.99	\$ (12.58)	0.88
2036	14	\$ 103.78	\$ 113.26	\$ (9.48)	0.92
2037	15	\$ 113.36	\$ 119.76	\$ (6.41)	0.95
2038	16	\$ 122.54	\$ 125.60	\$ (3.06)	0.98
2039	17	\$ 130.25	\$ 131.27	\$ (1.02)	0.99
2040	18	\$ 137.24	\$ 135.83	\$ 1.41	1.01
2041	19	\$ 143.98	\$ 140.10	\$ 3.89	1.03

Source: DEF response to LULAC/FR POD No. 2 at '2024 Rate Case Battery Study_40pctITC_Results.xlsx' and '2024 Rate Case Battery Study CPVRR Results.xlsx'.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for rate increase by Duke Energy
Florida, LLC.

Docket No. 20240025-EI

Dated: May 3, 2024

**DUKE ENERGY FLORIDA, LLC'S RESPONSE TO
FLORIDA RISING'S & LEAGUE OF UNITED LATIN AMERICAN CITIZENS'
FIRST SET OF INTERROGATORIES (NOS. 1-22)**

Duke Energy Florida, LLC ("DEF") responds to the League of United Latin
American Citizens of Florida ("LULAC") and Florida Rising's First Set of Interrogatories to DEF
(Nos. 1-22), as follows:

9. Please provide DEF's current loss of load probability, as well as any projected loss of load probabilities for 2025, 2026, 2027, and 2028.

Response:

DEF has not prepared a utility or BA specific LOLP study in the last several years. Because of the high level of integration of the DEF system into the FRCC system as a whole, the extensive use of reserve sharing and the existence of a single reliability coordinator for the state, it is more relevant to review data that incorporates the behavior of the entire interlinked system. In addition, over many years, DEF has established that maintaining the 20% utility reserve margin agreed to in previous PSC orders provides DEF with adequate resources to assure an LOLP below the 1 day in ten years target that is the industry standard.

FRCC performs a state-wide LOLP analysis every other year in even numbered years. DEF, along with all FRCC members, contributes data to that analysis and participates in review of the results. The following discussion is excerpted from the 2022 FRCC Reliability Analysis describing the results of the 2022 LOLP study.

For the 2022 LOLP analysis, the RS collected projected hourly solar output and energy storage charging and discharging profiles for all utility-scale units and treated them as a modifier to the load in order to further improve the assessment model. The purpose is to verify that the projected LOLP for the system does not exceed the maximum target LOLP of 0.1 day in a given year. In addition to maintaining this LOLP level, the FRCC established an additional Regional Reserve Margin Planning Criterion (also known as a Resource Adequacy Criteria) of a minimum 15% Total Reserve Margin for both summer and winter versus firm load.

The most recent LOLP analysis was conducted in 2022. “Base” LOLP projections were obtained for the FRCC Region for the years 2022 through 2026 using updated assumptions and forecasts that correspond with the Florida utilities’ 2022 TYSPs. Beyond the base or “reference” case values for LOLP, projected LOLP values for a variety of scenarios were considered, including: (i) no availability of firm imports, (ii) no availability of load management/demand response (DR) types of DSM programs, and (iii) a high load case.

Results indicate that the FRCC Region is projected to be reliable from an LOLP perspective through 2026. In other words, the FRCC Region’s electric system is projected not to exceed the planning maximum LOLP criterion of 0.1 days per year with all transmission facilities in service for the reference case and the scenario cases. The projected LOLP values are shown in Table 1.

Table 1
2022 FRCC LOLP Results

Year	Base Case	No Availability of Firm Imports	No Availability of Demand Response	High Case
	LOLP (Days/Year)	LOLP (Days/Year)	LOLP (Days/Year)	LOLP (Days/Year)
2022	0.000003	0.000957	0.015117	0.000008
2023	0.000003	0.000441	0.015003	0.000008
2024	0.000002	0.000652	0.014572	0.000009
2025	0.000004	0.000688	0.010994	0.000011
2026	0.000002	0.000597	0.008826	0.000009

The 2022 LOLP results are based on: (i) a load variation model and (ii) a manual approach to generator maintenance inputs which typically results in higher LOLP values than would result if using an automatic maintenance approach.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for rate increase by Duke Energy
Florida, LLC.

Docket No. 20240025-EI

Dated: May 8, 2024

**DUKE ENERGY FLORIDA, LLC'S RESPONSE TO
CITIZENS' FOURTH SET OF INTERROGATORIES (NOS. 71-79)**

Duke Energy Florida, LLC ("DEF") responds to the Citizens of the State of Florida, through the Office of Public Counsel's ("Citizens" or "OPC") Fourth Set of Interrogatories to DEF (Nos. 71-79), as follows:

74. Integrated Resource Plan Portfolio Fuel Price Forecast. Please refer to the Direct Testimony of Company Witness Borsch at 10.
 - a. Please describe in detail whether the Company used any fuel price forecasts in its IRP process for its planned resource additions besides its base case fuel price forecast.

- b. If the Company used additional fuel price forecasts in its IRP process for its planned resource additions besides its base case fuel price forecast, please identify and describe in detail each such additional fuel price forecast.
- c. If the Company did not use additional fuel price forecasts in its IRP process for its planned resource additions besides its base case fuel price forecast, please explain in detail why the Company did not do so.

Response:

DEF annually creates high and low fuel price scenarios. These price scenarios for the fall of 2022, i.e. contemporary to the forecast used in the 2023 TYSP, are included in DEF's response to Citizens POD 4-34.

- a. The company did not make use of the high and low fuel price scenarios in developing the TYSP used in developing testimony in this case.
- b. N/A
- c. Examination of the high and low fuel price scenarios indicated that they would not provide results that would be materially different from the base case forecast in the evaluation of the projected resource plan.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for rate increase by Duke Energy
Florida, LLC.

Docket No. 20240025-EI

Dated: May 8, 2024

**DUKE ENERGY FLORIDA, LLC'S RESPONSE TO
CITIZENS' FOURTH SET OF INTERROGATORIES (NOS. 71-79)**

Duke Energy Florida, LLC ("DEF") responds to the Citizens of the State of Florida, through the Office of Public Counsel's ("Citizens" or "OPC") Fourth Set of Interrogatories to DEF (Nos. 71-79), as follows:

75. **Solar Equivalent Firm Capacity Contribution.** Please refer to the Direct Testimony of Company Witness Borsch at 11.
- a. Please provide a detailed description of how the Company determined its approximately 1,050 MW of proposed solar generation additions for 2025-2027 have an expected equivalent summer firm capacity contribution of approximately 262 MW. This should include identification of any modeling tools used by the Company to make the determination.
 - b. Please identify the expected equivalent winter firm capacity contribution in MW of the approximately 1,050 MW of solar generation additions the Company has proposed for 2025-2027.
 - c. Please provide a detailed description of how the Company determined the value provided in response to b. above. This should include identification of any modeling tools used by the Company to make the determination.

Response:

- a. DEF regularly validates our assumption with actuals. Attachment OPC ROG 4 -75a 75b, bearing Bates numbers 20240025-OPCROG4-00018673 through 20240025-OPCROG4-00018674, shows that the average contribution for all the existing DEF owned solar units

at the time of the summer peak demand is 60%, which is close to the conservative assumption of 57% used in the DEF model.

b. The expected equivalent winter firm capacity contribution in MW of the approximately 1,050 MW of solar generation additions the Company has proposed for 2025-2027 is zero MW. DEF's winter peak is generally reached in January in the hour ending 8 am and the solar contribution at that time is zero.

DEF regularly validates our assumption with actuals. Attachment OPC ROG 4 -75a 75b shows that the average contribution for all the existing DEF owned solar units at the time of the winter peak demand is approximately 3%, which is in line with DEF's conservative assumption of 0%.

c. Please refer to response to LULAC ROG 1 – Q12 and LULAC POD ROG 1-Q01.

Capacity MWS	Solar Contribution to the Peak Demand				
	2023	2022	2021	2020	2019
74.9	92%				
74.9	63%	59%			
3.8	26%	53%	53%	53%	79%
74.9	68%				
74.9	55%	91%	59%	83%	
74.5	21%	62%	31%	68%	
74.5	60%	58%			
74.9	11%	45%			
74.9	56%	92%	45%	72%	95%
74.9	69%				
74.9	43%				
74.9	79%				
45	42%	60%	0%	100%	
74.9	21%				
5.1	39%	39%	39%	39%	39%
74.9	85%	60%			
74.9	48%	69%	77%		
8.8	45%	45%	11%	57%	80%
74.9	61%	65%	56%	76%	
74.9	64%	87%	49%		
59.91%	53%	63%	42%	69%	73%

HE	6PM	5PM	5PM	5PM	5PM

Units	Aug 2023	Jun 2022	Aug 2021	Jun 2020	Jun 2019
Bay Ranch Solar	69				
Bay Trail Solar	47	44			
Canoe Creek Solar	1	2	2	2	3
Charlie Creek Solar	51				
Columbia Solar	41	68	44	62	
Debary Solar	16	46	23	51	
Duette Solar	45	43			
Fort Green Solar	8	34	34	54	71
Hardeetown Solar	42	69			
Hamilton Solar	52				
High Springs Solar	32				
Hildreth Solar	59				
Lake Placid Solar	19	27	0	45	
Longleaf/Bell Ridge Solar	16				
Perry Solar	2	2	2	2	2
Sandy Creek Solar	64	45			
Santa Fe Solar	36	52	58		
Suwannee Solar	4	4	1	5	7
Trenton Solar	46	49	42	57	
Twin Rivers Solar	48	65	37		

Capacity MWS	Solar Contribution to the Peak Demand											
	2024	2023	2022	2021	2020	2019	2024	2023	2022	2021	2020	2019
74.9	28%											
74.9	29%	3%										
3.8	26%	26%	0%	0%	0%	0%						0%
74.9	39%	7%										
74.9	39%	4%	5%	4%								
74.5	23%	1%	4%	3%								
74.5	35%	4%	7%									
74.9	29%	0%										
74.9	31%											
74.9	35%	3%	3%	3%	3%	4%						
74.9	32%											
74.9	17%											
45	24%	2%	4%	4%	4%							
5.1	20%	0%	0%	0%	0%	0%						0%
74.9	29%	1%										
74.9	24%	0%	4%									
8.8	11%	0%	0%	11%	0%	0%						0%
74.9	16%	3%	4%									
74.9	32%	1%	3%	3%	1%							
6.67%	27%	4%	3%	3%	1%	1%						1%
2.53%												
HE	9AM	8AM	8AM	8AM	8AM	8AM	9AM	8AM	8AM	8AM	8AM	8AM

Units	2024	2023	2022	2021	2020	2019
Bay Ranch Solar	21					
Bay Trail Solar	22	2				
Canoe Creek Solar	1	1	0	0	0	0
Charlie Creek Solar	29	5				
Columbia Solar	29	3	4	3		
Debary Solar	17	1	3	2		
Duette Solar	26	3	5			
Fort Green Solar	22	0				
Hardeetown Solar	23					
Hamilton Solar	26	2	2	2	2	3
High Springs Solar	24					
Hildreth Solar	13					
Lake Placid Solar	11	1	2	2	2	
Perry Solar	1	0	0	0	0	0
Sandy Creek Solar	22	1				
Santa Fe Solar	18	0	3			
Suwannee Solar	1	0	0	1	0	0
Trenton Solar	12	2	3			
Twin Rivers Solar	24	1	2	2	1	

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for rate increase by Duke Energy
Florida, LLC.

Docket No. 20240025-EI

Dated: June 7, 2024

**DUKE ENERGY FLORIDA, LLC'S AMENDED RESPONSE TO
CITIZENS' SIXTH SET OF INTERROGATORIES (NOS. 118-143)**

Duke Energy Florida, LLC ("DEF") submits its second supplemental response to the Citizens of the State of Florida, through the Office of Public Counsel's ("Citizens" or "OPC") Sixth Set of Interrogatories to DEF (Nos. 118-143), specifically 118, as follows:

INTERROGATORIES**118. Resource Addition Timing**

Please refer to the Direct Testimony of DEF Witness Benjamin Borsch at p. 9-10 and p. 16 and the Company's April 2024 Ten-Year Site Plan.

- a. For each year from 2025 through 2026, inclusive, please identify each resource addition difference, if any, between the resource additions proposed by the Company in this proceeding and the resource additions proposed in the Company's April 2024 10-Year Site Plan.
- b. For each difference identified in response to a., please provide a detailed explanation with respect to why there is a difference.

Response:

- a. and b.

2025 – 2026 Solar Resources.

PLEASE NOTE THE INFORMATION IN THIS FILING IS NON-CONFIDENTIAL OR REDACTED

	Solar Units	2024 Rate Case		2024 TYSP		Differences	
		ISM	ISY	ISM	ISY		
1	Solar 2025	March	2025	March	2025		
2	Solar 2025	March	2025	December	2025	delayed	9 months
3	Solar 2025	December	2025	January	2026	delayed	1 month
4	Solar 2025	December	2025	January	2026	delayed	1 month
5	Solar 2025	December	2025	June	2026	delayed	6 months
6	Solar 2025	December	2025	June	2026	delayed	6 months
7	Solar 2026	June	2026	June	2026		
8	Solar 2026	June	2026	December	2026	delayed	6 months
9	Solar 2026	June	2026	December	2026	delayed	12 months
10	Solar 2026	June	2026	June	2027	delayed	12 months

Explanation for the 2025-2026 solar resources delays:

There has been a significant delay over the last year for High Side Breakers which are necessary to interconnect the solar site to the transmission grid. In May of 2023 lead times started to increase from 30 weeks to 155 weeks in February of 2024 and currently 170 weeks in April. This has made the ability to obtain breakers at the necessary timing extremely difficult. Due to these delays, the intended backfeed dates and in-service dates have slipped.

Combined Cycle Heat Rate Upgrades.

CC Heat Rate Upgrades	2024 Rate Case		2024 TYSP		Differences	
	ISM	ISY	ISM	ISY		
Bartow CC	November	2024	November	2024		
Citrus 1	December	2025	May	2026	delayed	5 months
Citrus 2	April	2026	May	2026	delayed	1 month
Hines 2	May	2025	May	2025		
Hines 3	May	2026	April	2026	accelerated	1 month
Hines 4	December	2027	November	2025	accelerated	25 months
Osprey	June	2023	June	2023		
Tiger Bay	May	2025	March	2026	delayed	10 months

Explanation for the change in schedule for the Combined Cycle Heat Rate upgrades:

Parts for these projects are being ordered and purchased, so the schedule is moving according to logistics constraints. DEF is trying to optimize the maintenance outages for its fleet, so the in-service days for the projects move accordingly.

185.

186. **Solar and Battery.** Refer to the testimony of Benjamin Borsch, at page 4, lines 20-22. Provide a list of the 1,050 MW solar projects and the 100 MW battery storage identifying, by each individual project, the planned starting date, planned in-service date and the projected cost. Also identify by each individual project whether permitting has been completed and if not completed, identify the status.

Response:

Please see attachment bearing Bates number 20240025-OPCROG7-00018141, for the requested information requested for the DEF owned solar projects with commercial operation dates from 2025-2027. The documents are confidential: redacted versions are attached hereto and unredacted copies have been submitted with the Florida Public Service Commission along with DEF's Notice of Intent to Request Confidential Classification dated May 7, 2024.

PLEASE NOTE THE INFORMATION IN THIS TABLE IS NON-CONFIDENTIAL OR REDACTED

2025 Solar	Named Project	Filing In Service Date	Planned In Service Date	Permitting Status	Planned Construction Start	Filed Project Cost	Anticipated Project Cost
2025 - Project #1	Sundance	March 2025	March 2025	Expected May 2024	May 2025		
2025 - Project #2	Rattler	March 2025	December 2025	Expected 3Q 2024	1Q 2025		
2025 - Project #3	Half Moon	December 2025	January 2026	Expected 3Q 2024	1Q 2025		
2025 - Project #4	Bailey Mill	December 2025	January 2026	Expected 3Q 2024	1Q 2025		
2025 - Project #5	-	December 2025	June 2026	Expected 1Q 2025	3Q 2025		
2025 - Project #6	-	December 2025	June 2026	Expected 1Q 2025	3Q 2025		
2026 - Project #1	-	June 2026	June 2026	Expected 1Q 2025	3Q 2025		
2026 - Project #2	-	June 2026	December 2026	Expected 3Q 2025	1Q 2026		
2026 - Project #3	-	June 2026	December 2026	Expected 3Q 2025	1Q 2026		
2026 - Project #4	-	June 2026	June 2027	Expected 1Q 2026	3Q 2026		
2027 - Project #1	-	June 2027	June 2027	Expected 1Q 2026	3Q 2026		
2027 - Project #2	-	June 2027	June 2027	Expected 1Q 2026	3Q 2026		
2027 - Project #3	-	June 2027	December 2027	Expected 3Q 2026	1Q 2027		
2027 - Project #4	-	June 2027	December 2027	Expected 3Q 2026	1Q 2027		

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BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

IN RE: PETITION FOR RATE
INCREASE BY DUKE ENERGY
FLORIDA, LLC.

DOCKET NO. 20240025-EI

_____ /

VOLUME II
(Pages 70 through 185)

VIDEO-TELECONFERENCE
DEPOSITION OF BENJAMIN BORSCH
(Taken on behalf of the Office of Public Counsel)

DATE TAKEN: May 30, 2024
TIME: 8:30 a.m. - 6:03 p.m.
PLACE: Zoom

Examination of the witness taken before:

JESSICA RENCHEN, Court Reporter
On Behalf of
For The Record Reporting

1 D E P O S I T I O N

2 (Deposition continued from Volume I)

3 THE COURT REPORTER: This is the Court
4 Reporter; I'm ready to go back on.

5 MS. WESSLING: Okay, great.

6 And Mr. Borsch, you're ready?

7 THE WITNESS: Ready.

8 CONTINUED EXAMINATION

9 BY MS. WESSLING:

10 Q. Okay. So I believe we were looking at
11 Schedule 8 of the revised 10-year site plan and --

12 A. Yes.

13 Q. Okay. I believe the question that I was
14 asking was, it looks like there are some proposed
15 combustion turbine generation facility retirements at
16 Bayboro, DeBary and Bartow in 2026 and 2027. Is that
17 accurate?

18 A. Yes.

19 Q. Okay. And is this information still
20 accurate?

21 A. Yes.

22 Q. Okay. If all three of these are retired,
23 that will result in approximately 460 megawatts of
24 summer capacity being retired, would you agree?

25 A. Subject to check, yes.

1 Q. Okay. Could you just explain how and why the ⁷⁵
2 decision was made to retire each of those units?

3 A. Yes. I mean, principally the reason that
4 we're retiring those units is that they're old. And
5 as they continue to age, maintenance gets trickier and
6 the reliability goes down and eventually costs will go
7 up.

8 In the specific case of Bayboro, where
9 Bayboro is located right next -- like just down the
10 street here from us here in St. Petersburg and right
11 next to the Bay, we have identified that there's a
12 significant environmental risk associated with the oil
13 tanks that are there at Bayboro. Now, mind you, to my
14 knowledge, we have never had a release. However, as
15 the tanks age, as the equipment ages, that
16 environmental risk does rise and that's a sensitive
17 and publicly visible waterway. So that really was one
18 of the key drivers of the decision to retire the
19 Bayboro units in particular.

20 The other units, those are all, first of all,
21 aging, but second of all, they're all oil fired units
22 with very low utilization rates. They are expensive
23 to operate because they are oil fired. And given that
24 we have been in a period of relatively high reserve
25 margins, there was an opportunity to retire those

1 units eventually. Meaning, closer to 2030 we'll build⁷⁶
2 capacity that will replace them, but it'll be new
3 capacity. As I say, most of those units are over 50
4 years old already.

5 Q. All right. And what analysis do you and your
6 group specifically do related to the retirements
7 contained in this 10-year site plan?

8 A. In this case, we didn't do a specific
9 analysis of those retirements. Because of the fact
10 that they are effectively at the ends of their lives,
11 a specific analysis didn't appear to be required. So
12 we worked with the generation group and it's really,
13 this is information that we're getting from Mr.
14 Anderson's department that from a maintenance
15 perspective and an age perspective that those units
16 are ready for retirement.

17 Q. So there is no analysis done about the
18 prudence or reasonableness of those proposed
19 retirements?

20 A. There is not a specific cost-effectiveness or
21 cost analysis of those retirements.

22 Q. Okay. Did you listen to Mr. Anderson's
23 deposition last Friday?

24 A. I did not.

25 Q. Okay. Well, he mentioned something called a

1 Q. Are you going to be making any amendments to
2 your testimony or BMHB-2 based off of the information
3 reflected in Staff's Interrogatory Number 2?

4 MS. TRIPLETT: Object to the form.

5 BY MS. WESSLING:

6 Q. Okay. Well, you can go ahead and answer.

7 A. Not that I'm aware of.

8 Q. Okay. All right. I'd like to discuss the
9 Clean Energy Connection Program with you for just a
10 moment. Are you aware that the original Clean Energy
11 Connection program is the subject of the appeal before
12 the Supreme Court right now?

13 A. Yes.

14 Q. If that program were to be struck down by the
15 Court, what would that mean for rate case?

16 MS. TRIPLETT: Object to the form.

17 THE WITNESS: I'll go with, I don't know.

18 BY MS. WESSLING:

19 Q. Five of the 14 proposed solar projects that
20 are being proposed in this case would be included in
21 the expansion of the company's Clean Energy Connection
22 Program, correct?

23 A. That's the proposal. Yes.

24 Q. Looking at page 17 of your testimony, I
25 believe that's where you described the cost

1 effectiveness analysis that you performed for the 14
2 solar projects together; is that correct?

3 A. It looks like it, yes.

4 Q. All right. I think we've discussed this, but
5 your Exhibit BMHB-3 provides the result of that
6 analysis, correct?

7 A. Yes.

8 Q. Okay. In this particular analysis, did you
9 model the five projects that would be part of an
10 expansion of the CEC program any differently than the
11 remaining nine projects?

12 A. No.

13 Q. Does this mean that the analysis treats all
14 of the proposed units as if they were pursued as a
15 normal company resource addition rather than as an
16 expansion of the CEC program?

17 A. Yes.

18 Q. All right. Now, on pages 18 through 20 of
19 your testimony, has Duke Energy Florida identified
20 which of the 14 solar projects will be a part of the
21 CEC2 program?

22 A. Yes.

23 Q. What are those?

24 A. I'm going to have to look for that.

25 Q. Okay.

1 A. I think I have a list here somewhere. Since
2 I don't seem to have a definitive list, I will tell
3 you best information that I have off of Schedule 8 of
4 the site plan is that those projects will be the
5 Sundance, Bailey Mill, Half Moon, and Rattler Projects
6 proposed for 2025 and one is yet unnamed project
7 proposed for June of 2026.

8 Q. So all four of the projects that are
9 estimated to be completed by the end of 2025 are four
10 of the five projects that will comprise the proposed
11 CEC2 program?

12 A. That is the plan, yes.

13 Q. Do you anticipate that the 2026 solar
14 facility that's unnamed, is that going to be the first
15 facility put into service in 2026?

16 A. We have three projects I think intended to be
17 coming into -- maybe it's only two. Let me just
18 double check here. Three projects intended to be
19 coming into service around the same time in the
20 midyear of 2026. It will be one of those. Whether it
21 turns out to be the very first one or not, I don't
22 know.

23 Q. Actually, I'm looking at the Schedule 8 of
24 the 2024 revised 10-year site plan, and I think I only
25 see two solar plans coming into service in 2026?

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BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In Re: Petition for Rate Increase by Duke
Energy Florida, LLC.

DOCKET NO.: 20240025-EI

DEPOSITION OF
VANESSA GOFF

Taken on Behalf of Public Counsel

DATE TAKEN: May 29, 2024
TIME: 1:30 p.m. - 4:41 p.m.
PLACE: Video Conference

Examination of the witness taken before:

CLARA C. ROTRUCK, Court Reporter
For the Record Reporting, Inc.
1500 Mahan Drive - Suite 140
Tallahassee, Florida 32308

1 MS. TRIPLETT: Object to the form.

2 THE WITNESS: I guess I'm not understanding
3 what you're asking.

4 The lease -- the facility is designed for 30
5 years. It should exist for 30 years. We have a
6 lease that covers 30 years. There is an option to
7 go longer, right? And that option would allow us
8 to extend the life of the project by just having to
9 pay for the lease, but not pay for -- I mean, we
10 went beyond what the option -- when the option runs
11 out, we wouldn't renegotiate with the landowner, I
12 don't believe. We would remove the facility.

13 BY MS. WESSLING:

14 Q So part of the case, which tell me if you're
15 familiar with or not, is improvements to existing
16 (inaudible) plants to (inaudible) efficiency, right?

17 A I'm aware.

18 Q Okay. So if there were some -- let's say in
19 10 or 15 years, some technology came out that could
20 allow for increased efficiency and extend the life of
21 these solar facilities that are at these locations, and
22 their service life was well beyond even all of the
23 possible extensions of the lease, that's what I'm asking
24 about is if these service lives (inaudible) beyond the
25 longest extension possible for these leases, wouldn't

**DUKE ENERGY FLORIDA, LLC'S RESPONSE TO LATE FILED EXHIBIT REQUEST
FOR REGINALD ANDERSON FROM DEPOSITION HELD ON MAY 24, 2024**

3. Late-filed deposition exhibit 3: heat rate upgrade reconciliation:

Response:

Regarding the timing of the Osprey upgrade, DEF completed the Osprey project in 2023. Accordingly, the Osprey project is reflected in Schedule 1 of the Ten Year Site Plan (TYSP). Schedule 8 of the TYSP reflects planned and prospective generating additions as of 12/31/23. Because Osprey was completed in 2023, the Osprey heat rate project is not reflected there. Regarding the number of projects, Exhibit RDA-3 reflects the correct number of projects (eight). DEF will update Mr. Borsch's testimony to reflect eight rather than seven (page 21). Mr. Borsch inadvertently counted the two Citrus CC power blocks as one unit rather than two as reflected in Mr. Anderson's exhibit. Finally, with respect to the difference in megawatts (428 total noted in Mr. Anderson's testimony versus 400 total noted in Mr. Borsch's testimony), the difference lies in the expected output of the Hines PB 4 unit after the heat rate project. When Mr. Borsch completed his cost effectiveness analysis in 2022, and when he completed Schedule 8 of the TYSP based on information known as of 12/31/2023, the Company expected to achieve 50 MW from the heat rate project. In January 2024, the Company received an update from the OEM indicating that additional modifications could be made to the steam turbine to increase the output by an additional 28 MW. This is significant value to DEF's customers, so DEF intends to pursue that additional output and included it in Exhibit RDA-3.