DUKE ENERGY FLORIDA

Stephanie A. Cuello
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March 6, 2025

VIA ELECTRONIC FILING

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

Re: Review of incentive mechanisms for the electric investor-owned utilities; Docket No. 20250032-EI

Dear Mr. Teitzman:

Please find attached for electronic filing Duke Energy Florida, LLC's Response to Staff's First Data Request.

Thank you for your assistance in this matter and if you have any questions, please feel free to contact me at (850) 521-1428.

Sincerely,

/s/ Stephanie A. Cuello

Stephanie A. Cuello

SAC/clg
Attachments

106 East College Avenue, Suite 800, Tallahassee, FL 32301
Phone: 850.521.1425 ■ Email: stephanie.cuello@duke-energy.com

CERTIFICATE OF SERVICE
Docket No. 20250032-EI

I HEREBY CERTIFY that a true and correct copy of the foregoing has been furnished via electronic mail to the following this 6th day of March, 2025.

/s/ Stephanie A. Cuello
Stephanie A. Cuello

Carlos Marquez / Shaw Stiller Office of General Counsel FL Public Service Commission 2540 Shumard Oak Blvd. Tallahassee, FL 32399-0850 CMarquez@psc.state.fl.us sstiller@psc.state.fl.us discovery-gcl@psc.state.fl.us J. Wahlen / M. Means / V. Ponder Ausley McMullen Tampa Electric Company P.O. Box 391 Tallahassee, FL 32302 jwahlen@ausley.com mmeans@ausley.com vponder@ausley.com William C. Garner Southern Alliance for Clean Energy 3425 Bannerman Road Unit 105, #414 Tallahassee, FL 32312 bgarner@wcglawoffice.com Bradley Marshall/Jordan Luebkemann Earthjustice 111 S. Martin Luther King Jr. Blvd. Tallahassee FL 32301 bmarshall@earthjustice.org jluebkemann@earthjustice.org	W. Trierweiler / C. Rehwinkel Office of Public Counsel 111 W. Madison St., Room 812 Tallahassee, FL 32399-1400 trierweiler.walt@leg.state.fl.us rehwinkel.charles@leg.state.fl.us Beth Keating Gunster, Yoakley & Stewart, P.A. Florida Public Utilities Company 215 South Monroe Street, Suite 601 Tallahassee, FL 32301 bkeating@gunster.com Christopher Wright Florida Power & Light Company 700 Universe Blvd Juno Beach, FL 33408-0420 christopher.wright@fpl.com

DUKE ENERGY FLORIDA, LLC'S (DEF), RESPONSE TO STAFF'S FIRST DATA REQUEST REGARDING REVIEW OF INCENTIVE MECHANISMS FOR THE ELECTRIC INVESTOR-OWNED UTILITIES

Docket No. 20250032-EI

The following questions are regarding the Utility's Generation Performance Incentive Factor (GPIF) performance:

1. Please describe what actions, if any, the Utility takes to ensure unit availability and/or heat rate improvement goals above typical industry practices as a result of the potential rewards or penalties associated with the GPIF.

   Response:
   Potential rewards or penalties from GPIF are not primary considerations in the Company's approach to providing reliable and affordable energy to customers. Instead, Duke Energy Florida maintains its fleet of generation units at reliability and efficiency levels that meet or exceed industry standards while controlling costs to deliver value customers expect.

2. Please identify what operations and maintenance (O&M) expenses above typical industry practices are associated with achieving the unit availability and/or heat rate improvement goals associated with the GPIF. If the Utility does not engage in additional O&M expenses associated with the GPIF, please state so.

   a. How are O&M expenses associated with GPIF tracked and/or estimated?

   b. How are O&M expenses associated with GPIF recovered?

   c. Please complete the table below providing information on the Utility's GPIF associated O&M costs for the period 2013 through 2024.Would the proposed revisions to Rule 25-14.004, F.A.C., directly or indirectly result in incremental regulatory costs to your utility in excess of $200,000 in the aggregate in Florida within 1 year after implementation of the rule?

Year	GPIF Associated O&M Costs
2013	
2014	
2015	
2016	
2017	
2018	
2019	
2020	
2021	
2022	
2023	

2024	

Response:
The Company does not engage in any additional O&M expenses associated with the GPIF.

3. Please complete the table below providing information on the Utility's potential GPIF rewards or penalties for the period 2013 through 2024. Provide the jurisdictional maximum allowed incentive based on a 25 basis point cap, the incentive cap based on 50 percent of maximum projected fuel savings, and the maximum reward and penalty, respectively.

Year	25 Basis Point Jurisdictional Calculation ($000)	50% Maximum Fuel Savings ($000)	Maximum Reward ($000)	Maximum (Penalty) ($000)
2013				
2014				
2015				
2016				
2017				
2018				
2019				
2020				
2021				
2022				
2023				
2024				

Response:

Year	25 Basis Point Jurisdictional Calculation ($000)	50% Maximum Fuel Savings ($000)	Maximum Reward ($000)	Maximum (Penalty) ($000)
2013	$19,475	$28,438	$19,475	($19,475)
2014	$20,923	$31,059	$20,923	($20,923)
2015	$20,711	$24,077	$20,711	($20,711)
2016	$20,230	$28,611	$20,230	($20,230)
2017	$20,942	$23,807	$20,942	($20,942)
2018	$19,679	$26,195	$19,679	($19,679)
2019	$21,234	$17,823	$17,823	($17,823)
2020	$23,636	$10,967	$10,967	($10,967)
2021	$25,954	$12,513	$12,513	($12,513)
2022	$29,268	$17,648	$17,648	($17,648)
2023	$31,720	$25,486	$25,486	($25,486)
2024	$35,095*	$18,235	$18,235	($18,235)

* Projected value. 2024 GPIF True-up to be filed mid-March 2025.

4. Please complete the table below providing information on the Utility's actual GPIF rewards or penalties for the period 2013 through 2024. Provide the actual fuel savings or losses, amount of shareholder incentive or penalty, and the net ratepayer savings or losses resulting from the GPIF.

Year	Actual Fuel Savings/(Losses) ($000)	Shareholder Incentive/(Penalty) ($000)	Net Ratepayer Savings/(Losses) ($000)
2013			
2014			
2015			
2016			
2017			
2018			
2019			
2020			
2021			
2022			
2023			
2024			

Response:

Year	Actual Fuel Savings/(Losses) ($000)	Shareholder Incentive/(Penalty) ($000)	Net Ratepayer Savings/(Losses) ($000)
2013	$6,518	$2,232	$4,286
2014	($29,750)	($8,614)	($21,136)
2015	$7,491	$2,255	$5,236
2016	$7,874	$2,793	$5,081
2017	($5,999)	($2,302)	($3,697)
2018	$6,900	$2,592	$4,308
2019	$8,815	$4,408	$4,408
2020	$5,315	$2,657	$2,657
2021	($473)	($206)	($267)
2022	$1,973	$987	$987
2023	$3,206	$1,603	$1,603
2024	$2,294*	$1,147*	$1,147*

* Projected value. 2024 GPIF True-up to be filed mid-March 2025.

The following questions are regarding wholesale energy transactions. Please answer each question with regards to wholesale energy purchases (as reported on Schedule A-7), economy energy purchases (as reported on Schedule A-9), and wholesale energy sales (as reported on Schedule A-6).

5. Describe how net gains are calculated with each type of wholesale energy transaction.

Response:
The gains on short-term wholesale power sales and the fuel savings on short-term wholesale power purchases are obtained from DEF's Schedule A6 for power sales and A9 for power purchases that are submitted to the Commission each month. Gains on short-term wholesale power sales as shown on the A6 are the difference between (1) Column 8 (Total Cost) and (2) Column 7 (Fuel Adj. Total). Fuel savings on short-term wholesale power purchases as shown on the A9 are the difference between (1) Column 7 (Cost if Generated) and (2) Column 5 (Total Amount for Fuel Adj). The A7 Schedule established by the Commission does not calculate purchase savings.

6. Describe how net gains are shared between ratepayers and shareholders with each type of wholesale energy transaction. As part of your response, describe how and where recovery of associated costs and benefits of the transaction occurs.

Response:
Per DEF's recent rate case settlement in Docket No. 20240025, DEF had its proposed Asset Optimization Mechanism approved. Beginning in 2025, per the AOM, on an annual basis, DEF customers will receive 100% of the gains up to a threshold of $4.9 million ("Customer Savings Threshold"). Incremental gains above the Customer Savings Threshold will be shared between DEF and customers as follows: DEF will retain 60% and customers will receive 40% of incremental gains between $4.9 million and $9.8 million; and DEF will retain 50% and customers will receive 50% of all incremental gains in excess of $9.8 million. Included in the gains are the A6 wholesale energy sales and the A9 economy purchases. The A7 purchases are not included in the AOM. All costs and benefits will be recovered via DEF's fuel clause factors.

7. Describe whether there is the risk of net losses with each type of wholesale energy transaction. As part of your response, describe if a net loss could occur with any particular type wholesale energy transaction, and if so, how would it be recovered.

   a. If net losses have occurred associated with any wholesale energy transactions within the 2013 through 2024 period, describe the circumstances resulting in the net losses for each relevant transaction or group of transactions.

   b. If net losses have occurred associated with any wholesale energy transactions within the 2013 through 2024 period, identify the annual amount of losses for each type of wholesale energy transaction.

Response:

As noted in response to Question #5, the A7 Schedule does not calculate purchase savings. For wholesale power sale and purchase transactions reported on Schedule A6 and A9, respectively, there are risks of net losses if the forecasted system cost unexpectedly changes from the time of power purchase or sale execution to the time of actual power flow. Unexpected changes in system cost can be a result of load over or under forecast, fuel price or availability changes, or generation changes (shutting down, starting up, otherwise limited), among other things. As DEF system conditions and power market conditions change over time, DEF can alternate between being more of a buyer or more of a seller. For the 2013 – 2024 period, when net losses associated with purchases were experienced, they were offset by net gains on sales. Please see the response to Question #20.

a. Net losses associated with Schedule A9 purchase activity occurred in 2015. Transmission expenses related to a multi-year purchase agreement was the primary driver of the net loss being reported on Schedule A9.

   Net losses associated with Schedule A9 purchase activity occurred in 2024. The primary driver of the net losses was due to transactions made to improve system reliability when Florida experienced (1) a prolonged period of hot temperatures in May and (2) impacts due to the hurricanes in the Fall of 2024.

b. Please refer to Years 2015 and 2024 purchase data associated with the table provided in response to Question 13.

8. Describe what incremental costs are associated with wholesale energy transactions, (staffing, software, hardware, subscriptions/memberships, data purchasing, etc.) excluding variable O&M. As part of your response, provide an estimate of how many incremental personnel work on wholesale energy transactions.

Response:

It takes a team of experienced professionals and a considerable amount of time to execute these types of transactions. DEF is not seeking capital or O&M cost recovery associated with any Asset Optimization Mechanisms (AOM) activity. The sharing mechanism provided as part of the AOM incentives the Company for the additional time spent executing these unique transactions. These responsibilities are in addition to the normal activities associated with meeting customer generation requirements. The AOM activities do not require capital to execute. Additionally, AOM activities do not require DEF to seek O&M costs recovery since this function will be absorbed by existing professionals and can only be executed based on market availability. These responsibilities are in addition to the normal activities associated with meeting customer generation requirements.

9. Describe how incremental costs are tracked by the Utility, or if not, why not. As part of your response, describe if these costs can be allocated to a single type of wholesale energy transaction or spread across multiple categories.

Response:
The Asset Optimization Mechanisms (AOM) activities do not require capital to execute. Additionally, AOM activities do not require DEF to seek O&M costs recovery since this function will be absorbed by existing professionals and can only be executed based on market availability. These responsibilities are in addition to the normal activities associated with meeting customer generation requirements. As a result, DEF does not have incremental costs to track.

10. Describe where incremental costs for each type of wholesale energy transactions are recovered in base rates or cost recovery clauses.

Response:
Please refer to DEF's response to question #8 and #9.

11. Please complete the table below providing information on the Utility's actual incremental costs for wholesale energy transactions for the period 2013 through 2024. Provide the annual cost for variable O&M associated with whole energy sales, the incremental staffing, software/hardware, and all other costs associated with wholesale energy transactions.

Year	Wholesale Sale Variable O&M Costs	Incremental Staffing Costs	Incremental Software/Hardware Costs	All Other Incremental Costs
2013				
2014				
2015				
2016				
2017				
2018				
2019				
2020				
2021				
2022				
2023				
2024				

Response:
As described in DEF's responses to questions #8 and #9, there are no incremental costs associated with AOM activity for wholesale energy transactions. Regarding variable O&M costs, please refer to the responses to Questions #12 - #14.

12. Please complete the table below providing information on the Utility's actual wholesale energy purchases, exclusive of economy energy purchases reported on Schedule A7, for the period 2013 through 2024. Provide the annual amount of wholesale purchases (in megawatt- hours and dollars), the total cost if generated, net fuel savings, avoided variable O&M costs, and total net gains.

Year	Wholesale Purchases (MWh)	Wholesale Purchases ($000)	Total Cost If Generated ($000)	Fuel Savings ($000)	Variable O&M Costs ($000)	Net Gains ($000)
2013						
2014						
2015						
2016						
2017						
2018						
2019						
2020						
2021						
2022						
2023						
2024						

Response:
Please see the below table.

Year	Wholesale Purchases (MWh)	Wholesale Purchases ($000)	Total Cost If Generated ($000)	Fuel Savings ($000)	Variable O&MCosts ($000)	Net Gains ($000)
2013	2,390,451	$ 118,628.0	*	*	**	*
2014	3,071,389	$ 152,874.0	*	*	**	*
2015	4,384,597	$ 173,229.0	*	*	**	*
2016	5,837,422	$ 221,111.0	*	*	**	*
2017	3,145,889	$ 139,833.0	*	*	**	*
2018	3,456,477	$ 163,860.0	*	*	**	*
2019	2,351,996	$ 93,905.0	*	*	**	*
2020	1,789,013	$ 65,801.0	*	*	**	*
2021	1,635,009	$ 110,046.0	*	*	**	*
2022	2,211,907	$ 245,226.0	*	*	**	*
2023	867,866	$ 48,598.0	*	*	**	*
2024	740,336	$ 36,967.0	*	*	**	*

* The A7 Schedule does not include the Total Cost if Generated, Fuel Savings or Net Gains

** The variable O&Mcosts charged per DEF's tolling agreements and/or PPAs are not tracked separately, but are included in the Wholesale Purchases cost in the above table. DEF does not have the avoided O&Mcosts available.

13. Please complete the table below providing information on the Utility's actual wholesale energy economy purchases reported on Schedule A9, for the period 2013 through 2024.

Provide the annual amount of wholesale purchases (in megawatt-hours and dollars), the total cost if generated, net fuel savings, avoided variable O&M costs, and total net gains.

Year	Wholesale Purchases (MWh)	Wholesale Purchases ($000)	Total Cost If Generated ($000)	Fuel Savings ($000)	Variable O&M Costs ($000)	Net Gains ($000)
2013						
2014						
2015						
2016						
2017						
2018						
2019						
2020						
2021						
2022						
2023						
2024						

Response:
Please see the below chart:

Year	Wholesale Purchases (MWh)	Wholesale Purchases ($000)	Total Cost If Generated ($000)	Fuel Savings ($000)	Variable O&MCosts ($000)	Net Gains ($000)
2013	343,846	$ 16,754.1	$ 18,028.5	$ 1,274.3	*	$ 1,274.3
2014	503,070	$ 26,223.0	$ 28,425.0	$ 2,202.0	*	$ 2,202.0
2015	83,260	$ 5,379.0	$ 3,943.3	$ (1,435.8)	*	$ (1,435.8)
2016	101,742	$ 4,740.5	$ 6,054.9	$ 1,314.5	*	$ 1,314.5
2017	246,153	$ 9,421.2	$ 12,233.1	$ 2,811.9	*	$ 2,811.9
2018	280,751	$ 13,166.6	$ 19,362.0	$ 6,195.3	*	$ 6,195.3
2019	144,528	$ 5,914.5	$ 7,982.8	$ 2,068.3	*	$ 2,068.3
2020	154,736	$ 4,748.8	$ 5,868.2	$ 1,119.4	*	$ 1,119.4
2021	638,193	$ 34,300.2	$ 41,694.1	$ 7,393.9	*	$ 7,393.9
2022	622,008	$ 65,525.6	$ 73,210.4	$ 7,684.7	*	$ 7,684.7
2023	520,579	$ 32,218.5	$ 37,167.1	$ 4,948.6	*	$ 4,948.6
2024	449,578	$ 28,324.4	$ 24,078.2	$ (4,246.2)	*	$ (4,246.2)

* Variable O&MCosts are not tracked separately for the Schedule A9, but they are included in the Total Cost if Generated column shown above

14) Please complete the table below providing information on the Utility's actual wholesale energy sales, for the period 2013 through 2024. Provide the annual total of wholesale sales (in megawatt-hours and dollars), associated fuel costs, variable O&M costs, and net gains.

Year	Wholesale Sales (MWh)	Wholesale Sales ($000)	Total Fuel Cost ($000)	Variable O&M Costs ($000)	Wholesale Sale Net Gains ($000)
2013					
2014					

2015					
2016					
2017					
2018					
2019					
2020					
2021					
2022					
2023					
2024					

Response:
Please see the below chart:

Year	Wholesale Sales (MWh)	Wholesale Sales ($000)	Total Fuel Cost ($000)	Variable O&MCosts ($000)	Wholesale Sale Net Gains ($000)
2013	59,667	$ 2,321.4	$ 1,894.3	*	$ 427.1
2014	148,605	$ 10,233.6	$ 5,740.0	*	$ 4,493.6
2015	193,138	$ 9,535.2	$ 5,814.6	*	$ 3,720.7
2016	83,577	$ 3,445.2	$ 2,601.3	*	$ 843.8
2017	70,215	$ 3,617.2	$ 2,729.8	*	$ 887.4
2018	59,720	$ 4,898.1	$ 2,628.2	*	$ 2,269.9
2019	151,162	$ 6,105.5	$ 4,456.4	*	$ 1,649.1
2020	132,534	$ 4,049.3	$ 2,825.6	*	$ 1,223.7
2021	400,762	$ 13,272.7	$ 10,417.4	*	$ 2,855.4
2022	430,508	$ 24,672.6	$ 19,214.5	*	$ 5,458.1
2023	321,659	$ 9,918.2	$ 6,812.2	*	$ 3,106.0
2024	635,233	$ 15,609.6	$ 11,155.5	*	$ 4,454.1

* Variable O&MCosts are not tracked separately, but theyare included in the Total Fuel Cost column shown above

15. Please complete the table below providing information on the Utility's actual wholesale energy sales incentives, for the period 2013 through 2024. Provide the annual net gains, the three year rolling average of wholesale sales, the amount of shareholder incentives received for wholesale sales, and the net ratepayer savings. For those years under which the Utility utilized an Asset Optimization Mechanism, exclude the shareholder incentives and net ratepayer savings values.

Year	Wholesale Sale Net Gains ($000)	Three Year Rolling Average Threshold ($000)	Shareholder Incentive ($000)	Net Ratepayer Savings ($000)
2013				
2014				
2015				
2016				
2017				
2018				
2019				

2020				
2021				
2022				
2023				
2024				

Response:
Please see the below chart. Note that for DEF none of the years in the chart utilized the Asset Optimization Mechanism.

Year	Wholesale Sale Net Gains ($000)	Three Year Rolling Average Threshold ($000)	Shareholder Incentive ($000)	Net Ratepayer Savings ($000)
2013	$ 427.1	$ 589.3	$ -	$ 427.1
2014	$ 4,493.6	$ 359.5	$ 826.8	$ 3,666.8
2015	$ 3,720.7	$ 1,739.8	$ 396.2	$ 3,324.5
2016	$ 843.8	$ 2,880.5	$ -	$ 843.8
2017	$ 887.4	$ 3,019.4	$ -	$ 887.4
2018	$ 2,269.9	$ 1,817.3	$ 90.5	$ 2,179.4
2019	$ 1,649.1	$ 1,333.7	$ 63.1	$ 1,586.0
2020	$ 1,223.7	$ 1,602.1	$ -	$ 1,223.7
2021	$ 2,855.4	$ 1,714.3	$ 228.2	$ 2,627.2
2022	$ 5,458.1	$ 1,909.4	$ 709.7	$ 4,748.3
2023	$ 3,106.0	$ 3,179.1	$ -	$ 3,106.0
2024	$ 4,454.1	$ 3,806.5	$ 129.5	$ 4,324.6

The following questions are regarding activities using ratepayer-supported assets to produce net gains, such as those activities included within the various Asset Optimization Mechanisms.

16. Provide a list of activities in which the Utility has attempted to produce net gains using ratepayer supported assets. These activities may include: release of electric transmission capacity, release of natural gas pipeline or storage capacity, sales of fuel by type and location, financial instruments associated with fuel, sales of renewable energy credits, sale of emissions credits, or other similar activities.

    For each activity identified above, please provide the following information:

    a. Describe the activity and how the net gains are calculated.

    b. Describe whether there is the risk of net losses with the activity. As part of your response, describe if a net loss could occur with the activity, and if so, how would it be recovered.

        i. If net losses have occurred associated with the activity within the 2013 through 2024 period, describe the circumstances resulting in the net losses.

ii. If net losses have occurred associated with the activity within the 2013 through 2024 period, identify the annual amount of losses.

c. Describe whether the activity was engaged in prior to the adoption of the Utility's Asset Optimization Mechanism. If so, provide the following information:

i. When did the Utility begin engaging in this activity?

ii. How were net gains allocated between ratepayers and shareholders?

iii. Where would cost recovery for these benefits occur (such as base rates or a cost recovery clause)?

Response:
Please refer to the below response to Question 16 (a) for the requested listing of activities.

a. Describe the activity and how the net gains are calculated.

The Company has historically engaged in some of the Asset Optimization Mechanisms (AOM) activities while two items will be new activities.

Previously Engaged Activities:

- Delivered gas sales using existing transport – Since 2018 - DEF may sell gas to Florida customers, using DEF's existing gas transportation capacity during periods when it is not needed to serve DEF's native electric load.
    - Net gains are calculated by taking the difference between daily price of the natural gas purchased plus applicable forwards haul fuel rate and usage charge (including surcharges), less the sales price of the delivered transaction times the volume sold to counterparty.

- Capacity release of gas transport – Since 2018 - DEF may sell temporarily available gas transportation and/or electric transmission capacity for short periods when it is not needed to serve DEF's native electric load.
    - Net gains are calculated by taking the pipeline capacity release quantity times the reservation rate times the term of the release in days.

- Asset Management Agreement – Since 2011 - DEF may outsource optimization functions to a third party through assignment of power, transportation and/or storage rights in exchange for a premium to be paid to DEF.
    - Net gains are calculated based on the AMA transaction structure currently in place. While past AMA transactions have included the following savings

described below, future transactions may be calculated differently or include other savings opportunities.

- Asset Management Payment Rate: During the Delivery Period, Counterparty shall reimburse DEF $0.XX per MMBtu per day.
- Contract Price Discount: The price for delivered gas at the delivery point will be the Platts Gas Daily less $0.XX per MMBtu.

- Coal Transportation Savings – Since 2020 - DEF may generate savings through the redeployment of transportation assets when they are not required for coal delivery.
  - Net gains are calculated based on the contracts at the time of the redeployment of the asset for a non-Duke Energy delivery. Generally speaking, for each hour/day of redeployment there is a mutually agreed upon credit reducing Duke's contractual obligation of the full utilization of the transportation asset. The reduction in the contractual obligation results in a net gain.

- Sales of Renewable Energy Credits – Since 2023 - Includes sales of RECs associated with DEF's Clean Energy Impact program. This mechanism would not include RECs transferred as part of DEF's Clean Energy Connection.
  - Net gains are calculated as the total revenue from (REC revenue and administrative fees) from REC sales less the total program administrative expenses, as approved by Order No. PSC-2023-0191-TRF-EI.

- Wholesale Fuel Purchase Savings – Revisions to the A Schedules were implemented in 1995. DEF has reported on fuel purchase savings since at least 1995.
  - Refer to the response to Question #5 for calculation of net gains.

- Wholesale Economy Sales – Prior to April 1, 1984 the Commission considered gains on Economy Sales in general base rate proceedings. Effective, April 1, 1984 Economy Sales were removed from base rates and included in the fuel clause and profits were divided between customers and shareholders on an 80% - 20% basis, respectively, with no threshold considered. The most recent incentive mechanism, which continued with 80% - 20% sharing but added a three-year moving average threshold, was approved in September 2000.
  - Refer to the response to Question #5 for calculation of net gains.

New Activities:

- Gas storage utilization – DEF may release contracted storage space or sell stored gas during non-critical demand seasons.
  - Net gains are calculated by taking the storage capacity release quantity times the reservation rate times the term of the release in days.

- Production (upstream) area sales - DEF may sell gas in the gas-production areas, using DEF's existing gas transportation capacity during periods when it is not needed to serve DEF's native electric load.

- Net gains are calculated by taking the difference between daily price of the natural gas purchased in the production area plus applicable forwards haul fuel rate and usage charge (including surcharges), less the sales price of the delivered transaction times the volume sold to counterparty.

b) Describe whether there is the risk of net losses with the activity. As part of your response, describe if a net loss could occur with the activity, and if so, how would it be recovered.

Response: Please see below for an explanation of the risk of net loss. Note that while there is a risk of net loss for the individual activities, as demonstrated in response to Question #20 DEF has not had a net loss for the 2013 – 2024 period when aggregating the activities. Any risk of loss for the AOM activities would be recovered via the fuel clause.

- Delivered gas sales using existing transport – At the time of the sale, DEF will make sure the natural gas purchase price plus applicable forwards haul fuel rate and usage charge (including surcharges) is less than sales price.

- Capacity release of gas transport – DEF would not release capacity at a negative reservation rate.

- Asset Management Agreement – Through the analysis of the AMA transaction, DEF attempts to reduce the chance of a net loss for the entire term of the transaction. DEF may include performance event, recall rights and supply source language in the Agreement to help reduce the likelihood of a net loss. There may be other events outside of DEF's control that result in a net loss from time to time for a month during the term of the transaction. However, it is DEF intention for a transaction to produce a net savings for the ratepayer.

- Coal Transportation Savings – There is no risk of net losses with this activity.

- Sales of Renewable Energy Credits - There is a risk of annual net loss associated with the sale of renewable energy credits (RECs) if sales revenue for RECS is less than the program administrative expenses associated with REC sales for the year.

- Wholesale Fuel Purchase Savings – Please refer to the response to Question #7.

- Wholesale Economy Sales – Please refer to the response to Question #7.

- Gas storage utilization – DEF would not release storage capacity at a negative reservation rate.

- Production (upstream) area sales – At the time of the transaction, DEF will make sure the natural gas purchase price of upstream production plus applicable forwards haul fuel rate and usage charge (including surcharges) is less than sales price.

i) If net losses have occurred associated with the activity within the 2013 through 2024 period, describe the circumstances resulting in the net losses.

Response: DEF realized a net loss for Fuel Purchase Savings in 2015 and 2024. Please refer to DEF's response to Question #7 for an explanation. DEF realized a net loss to Sales of Renewable Energy Credits (RECs) in 2023 and 2024 of $78K and $97K, respectively. DEF's Sales of RECs (CEI Program) is in its early stages as it was only implemented in August 2023, as approved by Order No. PSC-2023-0191-TRF-EI. As such, while DEF continues to work with, and educate, customers about the program its administrative expenses have been slightly above its revenue.

ii) If net losses have occurred associated with the activity within the 2013 through 2024 period, identify the annual amount of losses.

Response: Please see response to question #20.

c) Describe whether the activity was engaged in prior to the adoption of the Utility's Asset Optimization Mechanism. If so, provide the following information:

i) When did the Utility begin engaging in this activity?

Response: Please refer to DEF's response to Question #16 (a).

ii) How were net gains allocated between ratepayers and shareholders?

Response: All Asset Optimization Mechanisms (AOM) activities were allocated to the ratepayer through the fuel clause except for Economy Sales. Economy Sales (A6) – Effective, April 1, 1984 Economy Sales were removed from base rates and included in the fuel clause and profits were divided between customers and shareholders on a 80% - 20% basis, respectively, with no threshold considered. Approved in September 2000, this incentive mechanism added a three-year moving average threshold such that 100% of the net gains went to customers until the threshold was exceeded, then the net gains were shared 80%-20% sharing, with 80% to the customer and 20% to shareholders.

iii) Where would cost recovery for these benefits occur (such as base rates or a cost recovery clause)?

Response: With the exception of Economy Sales prior to 1984 (see response to Question #16 (c) (ii), all AOM benefits were recovered through the fuel clause. The AOM benefits will continue to be recovered in this manner under DEF's recently approved AOM.

17. Describe how incremental costs are tracked by the Utility, or if not, why not. As part of your response, describe if these costs can be allocated to a single type of activity or spread across multiple categories.

Response:
Please see the response to Questions # 8 and #9.

18. Describe where incremental costs for each type of activity are recovered in base rates or cost recovery clauses.

Response:
Please see the response to Questions #8 and #9.

19. Please complete the table below providing information on the Utility's actual incremental costs for asset optimization activities. Provide the annual cost for incremental staffing, software/hardware, and all other costs associated with wholesale energy transactions.

Year	Incremental Staffing Costs	Incremental Software/Hardware Costs	All Other Incremental Costs	Total Incremental Costs
2013				
2014				
2015				
2016				
2017				
2018				
2019				
2020				
2021				
2022				
2023				
2024				

Response:
DEF's AOM was approved under its recent rate case settlement and was implemented in January 2025. As stated in responses to Questions #8 - #10, DEF has no actual incremental costs for asset optimization activities.

20. Please complete the table below providing information on the Utility's actual asset optimization activities, for the period 2013 through 2024. Provide the annual savings by activity and total activity savings.

Year	Activity n Savings ($000)	Activity n+1 Savings ($000)	. . .	Total Activity Savings ($000)
2013				
2014				
2015				
2016				
2017				
2018				
2019				

2020				
2021				
2022				
2023				
2024				

Response:
Please see attached table. The document is 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 March 6, 2025.

21. Please complete the table below providing information on the Utility's actual asset optimization activities outside of an Asset Optimization Mechanism, for the period 2013 through 2024. Provide the annual total activity savings, incremental costs, amount of shareholder incentives, and net ratepayer savings. For those years under which the Utility utilized an Asset Optimization Mechanism, exclude the shareholder incentives and net ratepayer savings values.

Year	Total Activity Savings ($000)	Incremental Costs ($000)	Shareholder Incentive ($000)	Net Ratepayer Savings ($000)
2013				
2014				
2015				
2016				
2017				
2018				
2019				
2020				
2021				
2022				
2023				
2024				

Response:
Please see the response to Question #13 and #14.

The following questions are regarding the Utility's Asset Optimization Mechanisms.

22. For each Order approving an Asset Optimization Mechanism, provide the following information:

   a. Please describe how the Utility's threshold levels were determined. If they were partially based on historic savings, please identify what categories of savings and for what time period.

   b. Describe how the Utility's current sharing percentages by threshold were determined.

Response:

a. Per DEF's recent rate case settlement in Docket No. 20240025, DEF had its proposed Asset Optimization Mechanism approved. The approved number of thresholds in the Settlement are consistent with previously approved Asset Optimization Mechanisms for FPL's and TECO's incentive programs. The $4.9 million threshold represents the annual average short-term wholesale power purchase savings and gains on short-term wholesale power sales achieved by DEF for ten calendar years, which occurred over the most recent twelve calendar years (2012 – 2023) at the time of DEF's rate case proceeding, when excluding the highest (2022) and lowest (2012) years of gains. The next threshold, $9.8 million is two times the first threshold of $4.9 million. This threshold increase approximates the increase in FPL's and TECO's second thresholds, which are 2.4 (from $42.5 to $100 million) and 1.8 (from $4.5 million to $8.0 million) times their first thresholds, respectively.

b. The sharing percentages were based upon, and are consistent with, the existing Asset Optimization Mechanisms previously approved by the Commission for FPL and TECO.

23. Please complete the table below providing information on the Utility's actual Asset Optimization Mechanism activities savings and costs, for the period 2013 through 2024. Provide the annual total wholesale sale savings, wholesale purchase savings, asset optimization activity savings, incremental costs, net total asset optimization activity savings, the amount of shareholder incentives, and net ratepayer savings.

Year	Wholesale Purchase Savings ($000)	Wholesale Sale Savings ($000)	Asset Optimization Savings ($000)	Incremental Costs ($000)	Total AOM Savings ($000)	Shareholder Incentive ($000)	Net Ratepayer Savings ($000)
2013							
2014							
2015							
2016							
2017							
2018							
2019							
2020							
2021							
2022							
2023							
2024							

Response:

DEF's AOM was implemented January 1, 2025, and therefore DEF has no AOM savings, shareholder incentives, or net ratepayer incentives for the 2013 – 2024 period.

The below chart is a hypothetical scenario, assuming DEF had its currently approved AOM in place from 2013 – 2024. Please see the responses to Questions #8 - #10 regarding Incremental Costs.

Year	Wholesale Purchase Savings ($000)	Wholesale Sale Savings ($000)	Asset Optimization Savings ($000)	Incremental Costs ($000)	Total AOM Savings ($000)	Shareholder Incentive ($000)	Net Ratepayer Savings ($000)
2013	$ 1,274	$ 427	$ 5,772	N/A	$ 7,473	$ 1,544	$ 5,929
2014	$ 2,202	$ 4,494	$ 2,571	N/A	$ 9,267	$ 2,620	$ 6,647
2015	$ (1,436)	$ 3,721	$ 2,452	N/A	$ 4,737	$ -	$ 4,737
2016	$ 1,314	$ 844	$ 989	N/A	$ 3,147	$ -	$ 3,147
2017	$ 2,812	$ 887	$ 1,090	N/A	$ 4,789	$ -	$ 4,789
2018	$ 6,196	$ 2,270	$ 1,967	N/A	$ 10,433	$ 3,257	$ 7,177
2019	$ 2,069	$ 1,649	$ 2,793	N/A	$ 6,511	$ 967	$ 5,544
2020	$ 1,119	$ 1,224	$ 3,595	N/A	$ 5,938	$ 623	$ 5,315
2021	$ 7,394	$ 2,855	$ 4,044	N/A	$ 14,293	$ 5,187	$ 9,107
2022	$ 7,685	$ 5,458	$ 6,361	N/A	$ 19,504	$ 7,792	$ 11,712
2023	$ 4,949	$ 3,106	$ 10,368	N/A	$ 18,423	$ 7,251	$ 11,171
2024	$ (4,246)	$ 4,454	$ 10,025	N/A	$ 10,233	$ 3,156	$ 7,076

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Year	Gas Storage Utilization ($000)	Delivered Gas Sales - Using Existing Transport ($000)	Production (Upstream) Area Sales ($000)	Capacity Release of Gas Transport ($000)	Asset Management Agreement ($000)	Coal Tranpsortation Savings ($000)	Sales of Renewable Energy Credits ($000)	Fuel Purchases (A9) ($000)	Economy Sales (A6) ($000)	Total Activity Savings ($000)
2013	[redacted]	[redacted]	[redacted]	$ -	[redacted]	[redacted]	$ -	$ 1,274	$ 427	$ 7,473
2014	[redacted]	[redacted]	[redacted]	$ -	[redacted]	[redacted]	$ -	$ 2,202	$ 4,494	$ 9,267
2015	[redacted]	[redacted]	[redacted]	$ -	[redacted]	[redacted]	$ -	$ (1,436)	$ 3,721	$ 4,737
2016	[redacted]	[redacted]	[redacted]	$ -	[redacted]	[redacted]	$ -	$ 1,314	$ 844	$ 3,147
2017	[redacted]	[redacted]	[redacted]	$ -	[redacted]	[redacted]	$ -	$ 2,812	$ 887	$ 4,789
2018	[redacted]	[redacted]	[redacted]	$ 105	[redacted]	[redacted]	$ -	$ 6,196	$ 2,270	$ 10,433
2019	[redacted]	[redacted]	[redacted]	$ -	[redacted]	[redacted]	$ -	$ 2,069	$ 1,649	$ 6,511
2020	[redacted]	[redacted]	[redacted]	$ -	[redacted]	[redacted]	$ -	$ 1,119	$ 1,224	$ 5,938
2021	[redacted]	[redacted]	[redacted]	$ 38	[redacted]	[redacted]	$ -	$ 7,394	$ 2,855	$ 14,293
2022	[redacted]	[redacted]	[redacted]	$ 326	[redacted]	[redacted]	$ -	$ 7,685	$ 5,458	$ 19,504
2023	[redacted]	[redacted]	[redacted]	$ 835	[redacted]	[redacted]	$ (78)	$ 4,949	$ 3,106	$ 18,423
2024	[redacted]	[redacted]	[redacted]	$ 578	[redacted]	[redacted]	$ (97)	$ (4,246)	$ 4,454	$ 10,233