DUKE ENERGY
FLORIDA

Matthew R. Bernier
ASSOCIATE GENERAL COUNSEL

May 15, 2019

VIA ELECTRONIC MAIL

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

Re: *2019 TYSP Supplemental Data Request #1*

Dear Mr. Teitzman:

Please find attached for filing on behalf of Duke Energy Florida, LLC, its response to questions 1-82 of the 2019 TYSP Supplemental Data Request #1 issued on February 1, 2019. The requested Microsoft Excel documents will be provided via electronic mail.

Thank you for your assistance in this matter. Please feel free to call me at (850) 521-1428 should you have any questions concerning this matter.

Respectfully,

/s/ Matthew R. Bernier

Matthew R. Bernier

MRB/cmk
Attachment

cc: Doug Wright

General Items

1. Please provide an electronic copy of the Company's 2019–2028 Ten-Year Site Plan (2019 TYSP) in PDF format and the accompanying Schedules 1−10 in Microsoft Excel format.

   RESPONSE: Completed with filing of the DEF 2019 TYSP.

2. Please provide all data requested in the attached forms labeled "Appendix A." If any of the requested data is already included in the Company's 2019 TYSP, state so on the appropriate form.

   RESPONSE: Please see the Excel file DEF 2019 SDR1 - Appendix A.xlsx.

Load & Demand Forecasting

3. **[Investor-Owned Utilities Only]** Please provide, on a system-wide basis, the hourly system load for the period January 1, 2018, through December 31, 2018, in Microsoft Excel format.

   RESPONSE: Please see attached Excel File called DEF2018SystemHourlyMW.xlsx.

4. Please provide the monthly peak demand experienced in the period 2016–2018, including the actual peak demand experienced, the amount of demand response activated during the peak, and the estimated total peak if demand response had not been activated. Please also provide the day, hour, and system-average temperature at the time of each monthly peak.

   RESPONSE: Please see the table below and tab 4 of the Excel file DEF 2019 SDR1 - Tables.xlsx.

Historic Peak Demand Timing & Temperature

Year	Month	Actual Peak Demand (MW)	Demand Response Activated (MW)	Estimated Peak Demand (MW)	Day	Hour	System-Average Temperature (Degrees F)
2018	1	10320	0	10320	18	8	27.40
	2	6980	0	6980	26	16	83.75
	3	6462	0	6462	1	16	83.35
	4	6524	0	6524	9	18	85.45
	5	8094	0	8094	24	17	88.65
	6	8894	0	8894	22	16	91.15
	7	8740	0	8740	27	16	88.55
	8	9271	0	9271	8	17	92.55
	9	9147	0	9147	17	17	91.40
	10	8656	0	8656	16	17	90.80
	11	7361	0	7361	9	15	84.15
	12	7621	0	7621	12	8	40.40
2017	1	7538	0	7538	29	8	40.45
	2	6199	0	6199	22	17	84.70
	3	6969	0	6969	29	18	86.00
	4	8521	0	8521	28	17	92.05
	5	8724	0	8724	30	17	91.95
	6	8809	0	8809	22	17	90.25
	7	9293	0	9293	26	17	92.10
	8	9139	0	9139	7	17	91.40
	9	8795	0	8795	28	17	90.75
	10	8353	0	8353	9	16	89.05
	11	6509	0	6509	7	16	83.10
	12	7248	0	7248	11	8	41.30
2016	1	8336	0	8336	25	8	38.80
	2	8513	0	8513	11	8	41.25
	3	6721	0	6721	31	18	83.40
	4	8116	0	8116	29	17	89.55
	5	8312	0	8312	31	17	89.90
	6	9334	0	9334	14	17	92.40
	7	9646	0	9646	28	17	93.65
	8	9529	0	9529	22	17	93.40
	9	8734	0	8734	19	16	89.80
	10	7670	0	7670	5	17	89.60
	11	6557	0	6557	2	17	84.25
	12	6478	0	6478	19	16	80.60

Notes

Temperatures are at hour ended peak hour. System weighted St Pete (45%), Orlando (45%), and Tallahassee (10%).

5. Please identify the weather station(s) used for calculation of the system-wide temperature for the Company's service territory. If more than one weather station is utilized, please describe how a system-wide average is calculated.

<u>RESPONSE</u>: DEF utilizes three weather stations to calculate system-wide temperatures. St Petersburg (PIE), Orlando (MCO), and Tallahassee (TAL). The weighting scheme is 45%, 45% and 10%, respectively. These weights are consistent with, and observed by, DEF System Operations.

6. Please explain how the Company's load and demand forecasting used in its 2019 TYSP was developed. In your response please include the following information: methodology, assumptions, data sources, third-party consultant(s) involved, and any difference/improvement made compared with the load and demand forecasting used in the Company's 2018 Ten-Year Site Plan.

   <u>RESPONSE</u>: Please refer to the <u>Duke Energy Florida, LLC Ten-Year Site Plan</u> (April 1, 2019) pages 2-29 to 2-41 "Forecasting Methods and Procedures". The forecast continues to apply both end use (Itron, Inc.) and econometric methodologies. Direct contact with Large Account Management representatives provide input to specific company plans and operations as well. Assumptions continue to be refreshed when necessary using economic and demographic data sources from Moody's Analytics, Department of Energy (EIA) and University of Florida's BEBR. Our weather assumption remains a thirty-year average. Besides incorporating additional historical data, no significant improvements to the forecast were performed.

7. Please identify all closed and opened FPSC dockets and all non-docketed FPSC matters which were/are based on the same load forecast used in the Company's 2019 TYSP.

   <u>RESPONSE</u>: To date, the following docketed and non-docketed matters are based on the same load forecast used in DEF's 2019 TYSP
   - 2019 TYSP
   - SoBRA Cost Recovery Filing (Docket 20190072-EI)
   - DEF Standard Offer Contract (Docket 20190079-EI)
   - DSM Goals Filing (Docket 20199918-EI)

8. **[Investor-Owned Utilities Only]** Does your Company review the accuracy of its customer, load, and demand forecasts presented in its TYSP by comparing the actual data for a given year to the data forecasted one, two, three, four, five, or six years prior?

   a. If the response is affirmative, please explain the method used in such review.

RESPONSE: DEF has used a multi-year format of "Actual versus Projected" variance tables to track historic accuracy. The method compares each year of actual data between 2002 to 2019 for system summer peak, system winter peak, retail summer peak, retail winter peak, System Net Energy for Load and system customers to projected values published in each DEF TYSP from April 1, 2002 to April 1, 2018.

b. If the response is affirmative, please provide the results of such review for each forecast presented in the TYSPs filed, or to be filed, to the Commission from 2001 to 2019 with supporting workpapers in Microsoft Excel format.

RESPONSE: Please see Excel file labeled "TYSP Error Fan_2019.xlsx".

c. If the response is negative, please explain why not.

RESPONSE: N/A

9. Please explain any recent and forecasted trends in customer growth, by customer type (residential, commercial, industrial) and as a whole.

RESPONSE: DEF retail customer growth continued to improve in 2018 with total Retail customer growth hitting 27,242 – just below last year's growth breaking a string of eight straight years of increasing customer growth. Growth in residential customers continues its ninth year of consecutive improved growth but the commercial class growth dropped due to a weak retail sector reeling from online competition. Industrial customers declined for the fourteenth year in a row due to consolidations, foreign competition and locational disadvantages.

The Florida economy remained strong with favorable mortgage rates for homebuyers and new residents entering the State. Household formation growth is back to normal and the home construction industry is adding supply. New meter sets in 2018 totaled 31,496 versus 27,792 in 2017. This is more than double the number of new connects five years earlier.

The projection of customer growth calls for some caution. The residential sector reflects some caution due to evidence of rising housing prices out-pacing household income growth. Additionally, higher interest rates driven by announced Federal Reserve monetary policy will eventually create a further drag on housing affordability. It is our opinion that the housing market growth will crest during 2019. A weaker National & State economy is expected in 2020 as the stimulus from the Tax Cuts and Jobs Act fade away. Florida's service sector continues to drive commercial customer growth. Higher Statewide population and rising disposable incomes nationally should boost tourism and increased "Professional & Business Services" employment growth provides help, too.

Number of accounts in the Industrial class is expected to continue to drop but at a much slower pace. It is expected that the growing State population will provide improved "economies of scale" for manufacturers to set-up shop in the Sunshine state and minimize those leaving. We believe the decision made by Nucor Steel to open a "Re-Bar mini-mill" in Central Florida is a sign of things to come! The table below shows the annual change in DEF customers by retail Class (adjusted for re-routes and billing anomalies) from 2013 to 2028.

Annual Change in Billed Customers by Class

Year	RESID	COM	IND	Total
2013	13,881	1,661	-29	15,675
2014	22,694	1,738	-67	24,492
2015	23,591	2,224	-31	25,841
2016	24,361	2,113	-67	26,582
2017	24,405	2,718	-35	27,340
2018	25,091	1,978	-62	27,242
2019	27,558	2,709	-35	30,468
2020	22,750	2,458	-17	25,323
2021	26,555	2,332	-15	29,038
2022	26,220	2,261	-13	28,630
2023	26,210	2,164	-12	28,524
2024	25,937	2,142	-10	28,222
2025	25,157	2,119	-9	27,416
2026	24,978	2,046	-8	27,159
2027	24,416	1,950	-7	26,499
2028	23,179	1,872	-6	25,180

10. Please explain any recent and forecasted trends in electricity use per customer, by customer type (residential, commercial, industrial) and as a whole.

RESPONSE: The general trend in average usage has been downward as technology improvements have improved a wide variety of appliance efficiency levels. The greatest improvement in efficiency has been in lighting which impacts every class. Other factors include improved building shell and insulation levels in new construction and WIFI "space conditioning" thermostat technology. Declines in average usage over the forecast period are expected as the more efficient appliances increase their saturation levels. Impacts embedded in the DEF average usage projections like "behind the meter solar" and "Plug-in EVs" (PEVs) play a role in class average usage, too. Estimated residential class average KWh/customer reductions from cumulative rooftop solar installations range from 98 KWh in 2019 to 169 KWh in 2028. PEVs, conversely, are projected to boost usage per residential customer by under 3 KWh in 2019 to over 169 KWH by 2028. Again, these figures represent the impact upon the total class average usage levels. The Industrial class breaks from the downward trend shown in the other classes. This is solely due to large increases in expected load from specific large accounts. A large customer addition or "expansion" of operations from one large customer can play an oversized role on a class that doesn't have a large customer base. A large steel mill is projected to open in central Florida by July 2020. This will boost industrial sales as it ramps up to full operations during 2021. The customer is expected to take service under the interruptible tariff. Overall, the Retail total average usage is expected to decline as the large DEF residential and commercial classes continue to consume energy wisely.

The table below shows historical and projected values in class use per customer.

Billed KWH Per Customer by Class - W-Adjusted

Year	RESID	COM	IND	Total
2013	12,854	70,584	1,384,598	22,186
2014	12,713	70,562	1,436,440	22,000
2015	12,566	69,665	1,455,473	21,724
2016	12,806	69,555	1,466,383	21,814
2017	12,780	68,729	1,471,561	21,640
2018	12,713	68,541	1,491,834	21,468
2019	12,521	67,579	1,625,580	21,270
2020	12,527	67,440	1,733,824	21,323
2021	12,477	67,236	1,823,343	21,276
2022	12,396	66,944	1,846,982	21,126
2023	12,323	66,726	1,855,504	20,978
2024	12,234	66,445	1,861,527	20,811
2025	12,262	66,728	1,873,519	20,815
2026	12,135	66,075	1,870,687	20,577
2027	12,116	65,960	1,875,398	20,497
2028	12,207	66,316	1,886,807	20,574
CAGR:				
2018-28	-0.3%	-0.2%	1.7%	-0.4%

11. Please explain any recent and forecasted trends in peak demand by the sources of peak demand appearing in Schedule 3.1 of the 2019 TYSP.

RESPONSE: Much of the historical trend in the DEF coincident summer peak demand levels can also be explained by the same influences as the customer and use per customer trends. Fluctuations in economic activity, customer growth, efficiency improvements, self-service generation, Solar PV and PEV penetrations all play their role in the summer peak demand. Retail summer CP is expected to be driven by positive customer growth, but impacted somewhat by larger impacts from DR capability, behind the meter solar and plug-in electric vehicles. The expansion of a large mining account (2019-2020) and the opening of the new steel mill (2020-2021) are expected to boost DR MW as both customers are planned to be on an interruptible tariff. The level of DEF Wholesale MW has stabilized of late but is projected to increase in 2019 and 2020 as specific contracts roll in. More contracts are expected to terminate after 2022. As the DEF Plan shows, summer firm peak also endures an increasing amount of demand response capability.

The table below shows historical and projected DEF Summer Peak MW by Component.

DEF Recorded & Projected Summer Peak MW

YEAR	RETAIL	TOTAL WHOLESALE	TOTAL SYSTEM	TOTAL DR	TOTAL FIRM
2013	8,195	581	8,776	759	8,017
2014	8,404	814	9,218	695	8,523
2015	8,446	772	9,218	787	8,431
2016	8,753	893	9,646	700	8,946
2017	8,485	808	9,293	640	8,653
2018	8,459	812	9,271	726	8,545
2019	8,791	979	9,770	751	9,019
2020	8,858	939	9,797	844	8,953
2021	8,917	963	9,880	854	9,026
2022	8,993	963	9,956	874	9,082
2023	9,058	662	9,720	884	8,836
2024	9,139	662	9,801	895	8,907
2025	9,209	461	9,670	905	8,766
2026	9,293	461	9,754	915	8,839
2027	9,384	461	9,846	925	8,920
2028	9,502	461	9,963	935	9,027

12. **[Investor-Owned Utilities Only]** If not included in the Company's 2019 TYSP to be filed by April 1, 2019, please provide load forecast sensitivities (high band, low band) to account for the uncertainty inherent in the base case forecasts in the following TYSP schedules, as well as the methodology used to prepare each forecast:
    a. Schedule 2.1 – History and Forecast of Energy Consumption and Number of Customers by Customer Class
    b. Schedule 2.2 - History and Forecast of Energy Consumption and Number of Customers by Customer Class
    c. Schedule 2.3 - History and Forecast of Energy Consumption and Number of Customers by Customer Class
    d. Schedule 3.1 - History and Forecast of Summer Peak Demand
    e. Schedule 3.2 - History and Forecast of Winter Peak Demand
    f. Schedule 3.3 - History and Forecast of Annual Net Energy for Load
    g. Schedule 4 - Previous Year and 2-Year Forecast of Peak Demand and Net Energy for Load by Month.

RESPONSE: Please see the Duke Energy Florida, LLC Ten-Year Site Plan - April 2019 pages 2-4 through 2-24.

13. Please discuss whether the Company included plug-in electric vehicle (PEV) loads in its demand and energy forecasts for the 2019 TYSP. If so, how were these impacts accounted for in the modeling and forecasting process?

RESPONSE: Yes, expected plug-in electric vehicle energy loads are included in the TYSP energy forecast and have been since the 2014 TYSP energy forecast. There continues to be considerable uncertainty surrounding the actual future adoption rates and energy impacts. The cumulative impact of electric vehicle load on the system peak is also uncertain as there is limited real-world charging profile data to understand the potential coincident impact to the system. As more actual charging data becomes available from the Park and Plug and Charge Florida programs, continuous improvements to assumed hourly profiles will be incorporated.

14. Please discuss the methodology and the assumptions (or, if applicable, the source(s) of the data) used to estimate the number of PEVs operating in the Company's service territory and the methodology used to estimate the cumulative impact on system demand and energy consumption.

RESPONSE: DEF uses a market adoption plug-in electric vehicle dataset from the Electric Power Research Institute (EPRI) which estimates future scenarios of plug-in vehicle penetration in our territory. EPRI published a public report titled "Transportation Electrification: A Technology Overview" that contains a high-level summary of their prediction model at a national level along with the assumptions related to the low, medium, and high scenarios. DEF worked with EPRI to tailor the model to the utility's service territory level and include an estimate of energy consumption and load profiles for our territory. EPRI additionally tracks and provides historical electric vehicle sales by month to support forecast assumptions and revisions in the near-term.

15. Please include the following information within the Utility's service territory: an estimate of the number of PEVs, an estimate of the number of public PEV charging stations, an estimate of the number of public "quick-charge" PEV charging stations (i.e., charging stations requiring a service drop greater than 240 volts and/or using three-phase power), and the estimated demand and energy impacts of the PEVs by year. As part of this response, please provide an electronic version of the table below in Microsoft Excel format.

RESPONSE: Please see the table below and tab 15 of the Excel file DEF 2019 SDR1 - Tables.xlsx.

Electric Vehicle Charging Impacts

Year	Number of PEVs	Number of Public PEV Charging Stations	Number of Public "Quick-charge" PEV Charging Stations	Cumulative Impact of PEVs		
				Summer Demand (MW)	Winter Demand (MW)	Annual Energy (GWh)
2018	7,468	N/A	N/A	N/A	N/A	N/A
2019	11,149	N/A	N/A	0.8	0.0	5.7
2020	16,080	N/A	N/A	2.7	0.2	20.8
2021	22,669	N/A	N/A	5.3	0.6	40.9
2022	31,506	N/A	N/A	8.7	1.0	68.0
2023	42,591	N/A	N/A	13.1	1.5	103.5
2024	54,478	N/A	N/A	18.3	2.2	145.6
2025	69,019	N/A	N/A	24.2	3.0	193.3
2026	86,038	N/A	N/A	31.4	3.9	251.3
2027	104,722	N/A	N/A	39.5	5.0	317.2
2028	125,363	N/A	N/A	48.4	6.1	391.1

Notes

*Cumulative vehicle registrations as used in Load Forecast
Summer Demand: July HE 17 Winter Demand: January HE08
Number of Public PEV charging stations not currently forecasted by Duke Energy
Source: July 2018 EV Forecast (Annual Energy and Demand impacts are for new vehicles only)

16. Please describe any Company programs or tariffs currently offered to customers relating to PEVs, and describe whether any new or additional programs or tariffs relating to PEVs will be offered to customers within the 2019–2028 period.

    a. Of these programs or tariffs, are any designed for or do they include educating customers on electricity as a transportation fuel?

       RESPONSE: The Florida Pilot will spend up to $400,000 over the pilot period through December 2022 on general electric vehicle education and awareness. Duke Energy has also undergone a web site refresh to enhance web pages for consumer information of electric vehicles.

    b. Does the Company have any programs where customers can express their interest or expectations for electric vehicle infrastructure as provided for by the Utility, and if so, please describe in detail.

       RESPONSE: DEF introduced the "Charge Florida" program in 2019. This program places tracking devices in electric vehicles of those customers who have volunteered to participate and allow data capture of charging habits. Data collected for 2019 will serve as baseline for analysis of impacts on load in subsequent two years to follow. DEF will install 530 smart charging ports to collect and analyze charging infrastructure data.

17. Please describe how the Company monitors the installation of PEV public charging stations in its service area?

    <u>RESPONSE</u>: According to the Department of Energy's Alternative Fuels Data Center database, there are a total of 426 EV charging locations in DEF's service territory, with 44 of those offering DC fast charging.

    See attached file TYSP_SDR_Question_17_FL EV Charging By Zip.xlsx as a reference.

    Sources:
    http://www.afdc.energy.gov/fuels/data_methods_stations.html

    http://www.afdc.energy.gov/data_download/alt_fuel_stations_format

18. Please describe any instances since January 1, 2018, in which upgrades to the distribution system were made where PEVs were a contributing factor.

    <u>RESPONSE</u>: We are not aware of any specific upgrades to our distribution system since 1/1/2018 that would be attributed to a plug-in electric vehicle. Distribution upgrades, when they do occur, are often a result of a combination of factors and determining the existence and contribution of a single source such as a plug-in vehicle may be difficult.

19. Has the Company conducted or contracted any research to determine demographic and regional factors that influence the adoption of electric vehicles applicable to its service territory? If so, please describe in detail the methodology and findings.

    <u>RESPONSE</u>: The company has not studied demographic characteristics. The company launched its "Charge Florida" program in 2019 to better understand EV charging behaviors and some of this data may provide insights into vehicle adoption. 2019 will serve as collection of baseline data to perform further analysis in 2020 and 2021.

20. What processes or technologies, if any, are in place that allow the Utility to be notified when a customer has established an electrical vehicle charging station in the home?

    <u>RESPONSE</u>: None to date. The company's roll out of AMI meter network will potentially enable the company to identify electric vehicle loads in the future.

21. **[FEECA Utilities Only]** For each source of demand response, use the table below to provide the customer participation information listed on an annual basis. Please also provide a summary of all sources of demand response using the chart below. As part of

this response, please provide an electronic version of the table below in Microsoft Excel format.

RESPONSE: Please see the table below and tab 21 of the Excel file DEF 2019 SDR1 - Tables.xlsx.

All Demand Response Sources Combined									
Year	Beginning Year: Number of Customers	Available Capacity (MW)		New Customers Added	Added Capacity (MW)		Customers Lost	Lost Capacity (MW)	
		Sum	Win		Sum	Win		Sum	Win
2009	392,191	645	1,098	8,044	35	42	6,779	DNA	DNA
2010	393,410	679	977	8,384	24	31	3,946	DNA	DNA
2011	397,864	647	1,026	7,874	15	23	3,206	DNA	DNA
2012	402,379	696	920	5,582	11	16	1,953	DNA	DNA
2013	406,194	681	1,035	4,337	16	20	838	DNA	DNA
2014	409,689	724	1,014	3,156	23	27	1,977	DNA	DNA
2015	410,855	752	1,055	6,372	29	35	1,376	DNA	DNA
2016	415,838	714	1,014	8,782	79	88	1,569	DNA	DNA
2017	424,246	756	1,065	9,592	34	43	2,559	DNA	DNA
2018	429,750	783	1,090	6,478	42	51	2,545	DNA	DNA
Notes									
See note below									

Residential Load Management									
Year	Beginning Year: Number of Customers	Available Capacity (MW)		New Customers Added	Added Capacity (MW)		Customers Lost	Lost Capacity (MW)	
		Sum	Win		Sum	Win		Sum	Win
2009	391,511	291	759	8,009	10	17	6,757	5.9	13.1
2010	392,763	304	651	8,357	11	18	3,886	6.4	6.4
2011	397,234	317	661	7,858	9	17	3,163	6.2	5.2
2012	401,929	326	639	5,570	6	12	1,762	4.5	2.8
2013	405,737	341	652	4,321	5	9	831	1.0	3.8
2014	409,227	355	654	3,145	3	7	1,976	2.2	4.1
2015	410,396	357	656	6,345	7	13	1,372	1.5	2.8
2016	415,369	366	669	8,634	10	19	1,300	1.2	6.0
2017	423,900	382	694	9,561	11	20	2,553	2.9	4.2
2018	429,403	388	698	6,424	7	13	2,542	2.8	4.2
Notes									
See note below									

Commercial Load Management									
Year	Beginning Year: Number of Customers	Available Capacity (MW)		New Customers Added	Added Capacity (MW)		Customers Lost	Lost Capacity (MW)	
		Sum	Win		Sum	Win		Sum	Win
2009	316	8	0	0	0	0	0	1	0
2010	262	8	0	0	0	0	54	0	0
2011	250	6	0	0	0	0	12	2	0
2012	65	4	0	0	0	0	185	2	0
2013	65	4	0	0	0	0	0	0	0
2014	65	4	0	0	0	0	0	0	0
2015	64	4	0	0	0	0	1	0	0
2016	63	4	0	0	0	0	0	0	0
2017	63	4	0	0	0	0	0	0	0
2018	63	4	0	0	0	0	0	0	0
Notes									
See note below									

Standby Generation (4.)									
Year	Beginning Year: Number of Customers	Available Capacity (MW)		New Customers Added	Added Capacity (MW)		Customers Lost	Lost Capacity (MW)	
		Sum	Win		Sum	Win		Sum	Win
2009	212	84	71	32	8.4	8.4	16	DNA	DNA
2010	237	96	80	27	13.6	13.6	2	DNA	DNA
2011	234	97	94	16	5.8	5.8	19	DNA	DNA
2012	247	100	96	11	4.0	4.0	0	DNA	DNA
2013	253	98	98	12	4.7	4.7	4	DNA	DNA
2014	259	103	104	10	5.0	5.0	1	DNA	DNA
2015	260	108	109	25	19.5	19.5	2	DNA	DNA
2016	269	68	68	147	68	68	269	DNA	DNA
2017	145	77	77	28	7	7	5	DNA	DNA
2018	147	82	82	12.0	3.2	3.2	1	DNA	DNA
Notes									
See note below									

Interruptible Service									
Year	Beginning Year: Number of Customers	Available Capacity (MW)		New Customers Added	Added Capacity (MW)		Customers Lost	Lost Capacity (MW)	
		Sum	Win		Sum	Win		Sum	Win
2009	146	245	255	3	16.5	16.5	4	DNA	DNA
2010	143	254	233	0	0.0	0.0	3	DNA	DNA
2011	142	221	264	0	0.0	0.0	11	DNA	DNA
2012	134	262	179	1	0.6	0.6	6	DNA	DNA
2013	135	233	278	4	6.6	6.6	3	DNA	DNA
2014	134	256	249	1	15.0	15.0	0	DNA	DNA
2015	131	277	283	2	2.6	2.6	1	DNA	DNA
2016	133	270	270	1	1	1	0	DNA	DNA
2017	134	287	287	3	16	16	1	DNA	DNA
2018	133	303	303	42	32	34	2	DNA	DNA
Notes									
See note below									

Curtailable Service									
Year	Beginning Year: Number of Customers	Available Capacity (MW)		New Customers Added	Added Capacity (MW)		Customers Lost	Lost Capacity (MW)	
		Sum	Win		Sum	Win		Sum	Win
2009	6	17	13	0	0	0	2	DNA	DNA
2010	5	17	13	0	0	0	1	DNA	DNA
2011	4	6	7	0	0	0	1	DNA	DNA
2012	4	5	7	0	0	0	0	DNA	DNA
2013	4	5	7	0	0	0	0	DNA	DNA
2014	4	6	7	0	0	0	0	DNA	DNA
2015	4	6	7	0	0	0	0	DNA	DNA
2016	4	6	7	0	0	0	0	DNA	DNA
2017	4	6	7	0	0	0	0	DNA	DNA
2018	4	6	7	0	0	0	0	DNA	DNA
Notes									
See note below									

Table Footnotes:

(1) Total available capacity may change as a result of multiple factors including changes in participation, changes in contribution from existing participants, and periodic evaluation of system response. Thus, changes in total available capacity do not directly correlate to changes in participation.

(2) Added capacity corresponds to the addition of new participants and those converted from suspended accounts.

(3) Data is Not Available (DNA) on lost capacity for certain source programs and therefore is listed as DNA in their specific table and for the aggregated ALL Source Table.

(4) During 2016 the Emergency Stand-by Tariff was closed and the customers were removed from the program. Customers whose generators met new EPS requirements were added to the non-emergency program.

22. **[FEECA Utilities Only]** For each source of demand response, use the table below to provide the usage information listed on an annual basis. Please also provide a summary of all demand response using the chart below. As part of this response, please provide an electronic version of the table below in Microsoft Excel format.

RESPONSE: Please see the table below and tab 22 of the Excel file DEF 2019 SDR1 - Tables.xlsx.

All Sources of Demand Response Combined										
Year	Summer					Winter				
	Number of Events	Average Event Size		Maximum Event Size		Number of Events	Average Event Size		Maximum Event Size	
		(MW)	Number of Customers	(MW)	Number of Customers		(MW)	Number of Customers	(MW)	Number of Customers
2009	2	115	392,137	152	392,137	1	250	392,137	250	392,137
2010	6	52	395,236	68	395,236	16	514	395,384	943	395,384
2011	4	136	399,816	252	399,816	1	101	399,582	101	399,582
2012	2	16	404,080	16	404,080	0	0	0	0	0
2013	0	0	0	0	0	0	0	0	0	0
2014	0	0	0	0	0	0	0	0	0	0
2015	0	0	0	0	0	0	0	0	0	0
2016	0	0	0	0	0	0	0	0	0	0
2017	0	0	0	0	0	0	0	0	0	0
2018	0	0	0	0	0	0	0	0	0	0
Notes										

Residential Load Management										
Year	Summer					Winter				
	Number of Events	Average Event Size		Maximum Event Size		Number of Events	Average Event Size		Maximum Event Size	
		(MW)	Number of Customers	(MW)	Number of Customers		(MW)	Number of Customers	(MW)	Number of Customers
2009	2	115	392,137	152	392,137	1	250	392,137	250	392,137
2010	4	48	394,999	64	394,999	7	308	394,999	651	394,999
2011	2	101	399,582	188	399,582	1	101	399,582	101	399,582
2012	1	15	403,833	15	403,833	0	0	0	0	0
2013	0	0	0	0	0	0	0	0	0	0
2014	0	0	0	0	0	0	0	0	0	0
2015	0	0	0	0	0	0	0	0	0	0
2016	0	0	0	0	0	0	0	0	0	0
2017	0	0	0	0	0	0	0	0	0	0
2018	0	0	0	0	0	0	0	0	0	0
Notes										
* Activations shown are limited to reliability events for capacity shortages.										

Commercial Load Management

Year	Summer					Winter				
	Number of Events	Average Event Size		Maximum Event Size		Number of Events	Average Event Size		Maximum Event Size	
		(MW)	Number of Customers	(MW)	Number of Customers		(MW)	Number of Customers	(MW)	Number of Customers
2009	*	*	*	*	*	*	*	*	*	*
2010	*	*	*	*	*	*	*	*	*	*
2011	*	*	*	*	*	*	*	*	*	*
2012	*	*	*	*	*	*	*	*	*	*
2013	*	*	*	*	*	*	*	*	*	*
2014	*	*	*	*	*	*	*	*	*	*
2015	*	*	*	*	*	*	*	*	*	*
2016	*	*	*	*	*	*	*	*	*	*
2017	*	*	*	*	*	*	*	*	*	*
2018	*	*	*	*	*	*	*	*	*	*

Notes

Commercial Demand Response is included in Residential Table Above
Commercial Demand Response is a Summer-only program

Standby Generation

Year	Summer					Winter				
	Number of Events	Average Event Size		Maximum Event Size		Number of Events	Average Event Size		Maximum Event Size	
		(MW)	Number of Customers	(MW)	Number of Customers		(MW)	Number of Customers	(MW)	Number of Customers
2009	0	0	0	0	0	0	0	0	0	0
2010	2	4	237	4	237	5	63	237	70	237
2011	2	35	234	64	234	0	0	0	0	0
2012	1	1	247	1	247	0	0	0	0	0
2013	0	0	0	0	0	0	0	0	0	0
2014	0	0	0	0	0	0	0	0	0	0
2015	0	0	0	0	0	0	0	0	0	0
2016	0	0	0	0	0	0	0	0	0	0
2017	0	0	0	0	0	0	0	0	0	0
2018	0	0	0	0	0	0	0	0	0	0

Notes

Interruptible Service

Year	Summer					Winter				
	Number of Events	Average Event Size		Maximum Event Size		Number of Events	Average Event Size		Maximum Event Size	
		(MW)	Number of Customers	(MW)	Number of Customers		(MW)	Number of Customers	(MW)	Number of Customers
2009	0	0	0	0	0	0	0	0	0	0
2010	0	0	0	0	0	2	122	143	201	143
2011	0	0	0	0	0	0	0	0	0	0
2012	0	0	0	0	0	0	0	0	0	0
2013	0	0	0	0	0	0	0	0	0	0
2014	0	0	0	0	0	0	0	0	0	0
2015	0	0	0	0	0	0	0	0	0	0
2016	0	0	0	0	0	0	0	0	0	0
2017	0	0	0	0	0	0	0	0	0	0
2018	0	0	0	0	0	0	0	0	0	0

Notes

Curtailable Service										
Year	Summer					Winter				
	Number of Events	Average Event Size		Maximum Event Size		Number of Events	Average Event Size		Maximum Event Size	
		(MW)	Number of Customers	(MW)	Number of Customers		(MW)	Number of Customers	(MW)	Number of Customers
2009	0	0	0	0	0	0	0	0	0	0
2010	0	0	0	0	0	2	21	5	21	5
2011	0	0	0	0	0	0	0	0	0	0
2012	0	0	0	0	0	0	0	0	0	0
2013	0	0	0	0	0	0	0	0	0	0
2014	0	0	0	0	0	0	0	0	0	0
2015	0	0	0	0	0	0	0	0	0	0
2016	0	0	0	0	0	0	0	0	0	0
2017	0	0	0	0	0	0	0	0	0	0
2018	0	0	0	0	0	0	0	0	0	0
Notes										

23. **[FEECA Utilities Only]** For each source of demand response, use the table below to provide the seasonal peak activation information listed on an annual basis. Please also provide a summary of all demand response using the chart below. As part of this response, please provide an electronic version of the table below in Microsoft Excel format.

RESPONSE: Please see the table below and tab 23 of the Excel file DEF 2019 SDR1 - Tables.xlsx.

All Sources of Demand Response Combined							
Year	Average Number of Customers	Summer Peak			Winter Peak		
		Activated During Peak?	Number of Customers Activated	Capacity Activated	Activated During Peak?	Number of Customers Activated	Capacity Activated
		(Y/N)		(MW)	(Y/N)		(MW)
2009	392,816	Y	392,763	14	N	0	0
2010	395,649	N	0	0	Y	397,621	1,105
2011	400,220	N	0	0	N	0	0
2012	404,286	N	0	0	N	0	0
2013	407,929	N	0	0	N	0	0
2014	410,267	N	0	0	N	0	0
2015	413,339	N	0	0	N	0	0
2016	419,444	N	0	0	N	0	0
2017	427,023	N	0	0	N	0	0
2018	431,007	N	0	0	N	0	0
Notes							
(Include Notes Here)							

Residential Load Management							
Year	Average Number of Customers	Summer Peak			Winter Peak		
		Activated During Peak? (Y/N)	Number of Customers Activated	Capacity Activated (MW)	Activated During Peak? (Y/N)	Number of Customers Activated	Capacity Activated (MW)
2009	392,137	Y	392,763	14	N	0	0
2010	394,999	N	0	0	Y	397,234	831
2011	399,582	N	0	0	N	0	0
2012	403,833	N	0	0	N	0	0
2013	407,482	N	0	0	N	0	0
2014	409,812	N	0	0	N	0	0
2015	412,883	N	0	0	N	0	0
2016	419,036	N	0	0	N	0	0
2017	426,651	N	0	0	N	0	0
2018	430,633	N	0	0	N	0	0
Notes							
(Include Notes Here)							

Commercial Load Management							
Year	Average Number of Customers	Summer Peak			Winter Peak		
		Activated During Peak? (Y/N)	Number of Customers Activated	Capacity Activated (MW)	Activated During Peak? (Y/N)	Number of Customers Activated	Capacity Activated (MW)
2009	316	*	*	*	*	*	*
2010	262	*	*	*	*	*	*
2011	250	*	*	*	*	*	*
2012	65	*	*	*	*	*	*
2013	65	*	*	*	*	*	*
2014	65	*	*	*	*	*	*
2015	64	*	*	*	*	*	*
2016	64	*	*	*	*	*	*
2017	63	*	*	*	*	*	*
2018	63	*	*	*	*	*	*
Notes							
* Commercial Demand Response is included in Residential Table above Commercial Demand Response is a Summer-only program							

Standby Generation							
Year	Average Number of Customers	Summer Peak			Winter Peak		
		Activated During Peak? (Y/N)	Number of Customers Activated	Capacity Activated (MW)	Activated During Peak? (Y/N)	Number of Customers Activated	Capacity Activated (MW)
2009	210	N	0	0	N	0	0
2010	240	N	0	0	Y	240	56
2011	242	N	0	0	N	0	0
2012	249	N	0	0	N	0	0
2013	253	N	0	0	N	0	0
2014	259	N	0	0	N	0	0
2015	259	N	0	0	N	0	0
2016	208	N	0	0	N	0	0
2017	172	N	0	0	N	0	0
2018	153	N	0	0	N	0	0
Notes							
(Include Notes Here)							

Interruptible Service							
Year	Average Number of Customers	Summer Peak			Winter Peak		
		Activated During Peak? (Y/N)	Number of Customers Activated	Capacity Activated (MW)	Activated During Peak? (Y/N)	Number of Customers Activated	Capacity Activated (MW)
2009	146	N	0	0	N	0	0
2010	143	N	0	0	Y	143	208
2011	142	N	0	0	N	0	0
2012	135	N	0	0	N	0	0
2013	125	N	0	0	N	0	0
2014	127	N	0	0	N	0	0
2015	129	N	0	0	N	0	0
2016	132	N	0	0	N	0	0
2017	133	N	0	0	N	0	0
2018	154	N	0	0	N	0	0
Notes							
(Include Notes Here)							

Curtailable Service							
Year	Average Number of Customers	Summer Peak			Winter Peak		
		Activated During Peak?	Number of Customers Activated	Capacity Activated	Activated During Peak?	Number of Customers Activated	Capacity Activated
		(Y/N)		(MW)	(Y/N)		(MW)
2009	7	N	0	0	N	0	0
2010	5	N	0	0	Y	4	10
2011	4	N	0	0	N	0	0
2012	4	N	0	0	N	0	0
2013	4	N	0	0	N	0	0
2014	4	N	0	0	N	0	0
2015	4	N	0	0	N	0	0
2016	4	N	0	0	N	0	0
2017	4	N	0	0	N	0	0
2018	4	N	0	0	N	0	0
Notes							
(Include Notes Here)							

Generation & Transmission

24. Please identify and describe each existing utility-owned renewable resource as of December 31, 2018, that delivered energy during the year. Please include the facility's name, unit type, fuel type, its installed capacity (AC-rating for photovoltaic (PV) systems), its net firm capacity or contribution during peak demand (if any), capacity factor for 2018 based off of the installed capacity, and its in-service date. For multiple small distributed renewable resources (<250 kW per installation), such as rooftop solar panels, please include a single combined entry for the resources that share the same unit & fuel type. As part of this response, please provide an electronic version of the table below in Microsoft Excel format.

RESPONSE: Please see the table below and tab 24 of the Excel file DEF 2019 SDR1 - Tables.xlsx.

Existing Utility-Owned Renewable Resources

Facility Name	Unit Type	Fuel Type	Installed Capacity (MW)		Net Firm Capacity (MW)		Capacity Factor	In-Service Date
			Sum	Win	Sum	Win	(%)	(MM/YYYY)
Econolockhatchee Photovoltaic Array	PV	SO	0.007	0.007	0	0	17	01/1989
Osceola	PV	SO	3.8	3.8	2	0	18	05/2016
Perry	PV	SO	5.1	5.1	2	0	11	07/2016
Suwannee	PV	SO	8.8	8.8	4	0	19	12/2017
Hamilton	PV	SO	74.9	74.9	43	0	n/a	12/2018
Notes								
(Include Notes Here)								

25. Please identify and describe each planned utility-owned renewable resource for the period 2019–2028. Please include each proposed facility's name, unit type, fuel type, its installed capacity (AC-rating for PV systems), its net firm capacity or anticipated contribution during peak demand (if any), anticipated typical capacity factor, and projected in-service date. For multiple small distributed renewable resources (<250 kW per installation), such as rooftop solar panels, please include a single combined entry for the resources that share the same unit & fuel type. As part of this response, please provide an electronic version of the table below in Microsoft Excel format.

RESPONSE: Please see the table below and tab 25 of the Excel file DEF 2019 SDR1 - Tables.xlsx.

Planned Utility-Owned Renewable Resources

Facility Name	Unit Type	Fuel Type	Installed Capacity (MW)		Net Firm Capacity (MW)		Capacity Factor	In-Service Date
			Sum	Win	Sum	Win	(%)	(MM/YYYY)
St Pete Pier	PV	SO	0.4	0.4	0.2	0	22	12/2019
Trenton	PV	SO	74.9	74.9	42.7	0	29	12/2019
Lake Placid	PV	SO	45	45	25.7	0	29	12/2019
Columbia	PV	SO	74.9	74.9	42.7	0	29	3/2020
Debary	PV	SO	74.5	74.5	33.5	0	28	3/2020
Solar #10	PV	SO	74.9	74.9	42.7	0	29	12/2020
Solar #11	PV	SO	74.9	74.9	42.7	0	29	12/2021
Solar #12	PV	SO	74.9	74.9	42.7	0	29	12/2021
Solar #13	PV	SO	55	55	31.4	0	29	12/2021
Solar #14	PV	SO	74.9	74.9	42.7	0	29	01/2022
Solar #15	PV	SO	74.9	74.9	42.7	0	29	01/2022
Solar #16	PV	SO	74.9	74.9	42.7	0	29	12/2023
Solar #17	PV	SO	74.9	74.9	42.7	0	29	12/2024
Solar #18	PV	SO	74.9	74.9	42.7	0	29	12/2024
Solar #19	PV	SO	74.9	74.9	42.7	0	29	12/2025
Solar #20	PV	SO	74.9	74.9	42.7	0	29	12/2025
Solar #21	PV	SO	74.9	74.9	42.7	0	29	12/2026
Notes								
(Include Notes Here)								

26. Please refer to the list of planned utility-owned renewable resources for the period 2019–2028 above. Discuss the current status of each project.

RESPONSE: DEF is generally focused on the development of cost-effective solar projects for the period 2019 – 2022 in accordance with the 2017 approved settlement.

Under Docket #20180149, DEF announced its first universal scaled solar power plant in Hamilton County that was placed in December 2018. Under this same docket, DEF announced its solar power plant to be located in Columbia County which is on schedule to be placed in service during the first quarter of 2020. DEF's Columbia Solar Power Plant has a completed Interconnection Agreement, Land Lease Agreement, Environmental Resource Permit, and EPC Contract. Site mobilization is targeted for mid-summer. Under Docket #20190072, DEF announced its next set of cost-effective solar power plants in Highlands, Gilchrist, and Volusia Counties. DEF's Lake Placid and Trenton Solar Power Plants will also begin site mobilization this summer and are expected online by the end of 2019. DEF's DeBary Solar Power Plant will also begin site construction late this summer and is scheduled to be placed in service during the first quarter of 2020. DEF continues to work and negotiate with solar companies that are also developing universal scaled solar projects throughout Florida as well as greenfield developments to identify cost-effective solar projects for the benefit of all of DEF customers for the balance of the period through 2022. From the period 2022 – 2028 DEF continues to project that cost-effective solar should be available for system needs; however, this forecast relies on the forward-looking price for land, PV technology, panel supplies, the value rendered by this technology, and considerations to other emerging and cost-effective renewable alternatives and may change the plan in response to these factors. The DEF forecast for renewables out through 2028 reveals about 1,500 MW of solar PV generation to be installed.

27. Please list and discuss any planned utility-owned renewable resources within the past year that were cancelled, delayed, or reduced in scope. What was the primary reason for the changes? What, if any, were the secondary reasons?

    RESPONSE: In DEF's 2018 TYSP, the St. Petersburg Pier Project was delayed and changed size to align with the city's new pier project scheduling. Solar #6 has become the Trenton Solar Power Plant now sized at 74.9 MW with a refined capacity factor. Solar #7 has become the Lake Placid Solar Power Plant with a refined capacity factor. Solar #8 has become the Columbia Solar Power Plant that is 74.9 MW in size with a refined capacity factor. Solar Facilities #10-#21 have new nameplate ratings at 74.9 MW and projected in-service dates that better align with project management refinements. DEF's plan for cost-effective solar facilities continues to be refined as we update forward looking solar pricing, PV technologies, siting, and the value rendered by this technology.

28. Please identify and describe each purchased power agreement with a renewable generator that delivered energy during 2018. Provide the name of the seller, the name of the generation facility associated with the contract, the unit type of the facility, the fuel type, the facility's installed capacity (AC-rating for PV systems), the amount of contracted firm capacity (if any), and the start and end dates of the purchased power agreement.

    RESPONSE: Please see the table below and tab 28 of the Excel file DEF 2019 SDR1 - Tables.xlsx.

Existing Renewable Purchased Power Agreements

Seller Name	Facility Name	Unit Type	Fuel Type	Installed Capacity (MW)		Contracted Firm Capacity (MW)		In-Service Date	Contract Term (MM/YY)	
				Sum	Win	Sum	Win	(MM/YY)	Start	End
Firm										
Pasco County	Pasco County Resource Recovery	ST	MSW	23	23	23	23	1/95	1/95	12/24
Pinellas County	Pinellas County Resource Recovery	ST	MSW	54.75	54.75	54.75	54.75	1/95	1/95	12/24
Waste Management	Ridge Generating Station	ST	WDS	39.6	39.6	39.6	39.6	8/94	8/94	12/23*
Florida Power Development	Florida Power Development	ST	WDS	60	60	60	60	5/14	12/13	11/33*
Non Firm										
Lake County	Lake County Resource Recovery	ST	MSW	12.75	12.75	N/A	N/A	1/95	7/14	N/A
Dade County	Metro-Dade County Resource Recovery	ST	MSW	43	43	N/A	N/A	11/91	1/14	N/A
Lee County	Lee County Resource Recovery	ST	MSW	40	40	N/A	N/A	1/2017	1/2017	N/A
PCS Phosphate	Swift Creek	ST	WH	N/A	N/A	N/A	N/A	11/80	N/A	N/A
Notes										
* Contract terminated as of 2018										

29. Please identify and describe each purchased power agreement with a renewable generator that is anticipated to begin delivering renewable energy to the Company during the period 2019–2028. Provide the name of the seller, the name of the generation facility associated with the contract, the unit type of the facility, the fuel type, the facility's installed capacity (AC-rating for PV systems), the amount of contracted firm capacity (if any), and the start and end dates of the purchased power agreement.

<u>RESPONSE</u>: Please see the table below and tab 29 of the Excel file DEF 2019 SDR1 - Tables.xlsx.

Renewable Purchased Power Agreements

Seller Name	Facility Name	Unit Type	Fuel Type	Installed Capacity (MW)		Contracted Firm Capacity (MW)		In-Service Date	Contract Term (MM/YY)	
	-	-	-	Sum	Win	Sum	Win	(MM/YY)	Start	End
Non-Firm										
National Solar	National Solar Gadsden	PV	SO	50	50	n/a	n/a	TBD	n/a	n/a
National Solar	National Solar Hardee	PV	SO	50	50	n/a	n/a	TBD	n/a	n/a
National Solar	National Solar Suwannee	PV	SO	50	50	n/a	n/a	TBD	n/a	n/a
National Solar	National Solar Highlands	PV	SO	50	50	n/a	n/a	TBD	n/a	n/a
National Solar	National Solar Osceola	PV	SO	50	50	n/a	n/a	TBD	n/a	n/a
Notes										
* As of 12/31/18 over 6,100MW of solar PV technology has initiated grid interconnection activity in Florida										

30. Please refer to the list of renewable purchased power agreements that are anticipated to begin delivering capacity and/or energy to the Company during the period 2019–2028. Discuss the current status of each project.

    RESPONSE: National Solar is continuing to negotiate with various counties to obtain land and secure financing.

31. Please list and discuss any renewable purchased power agreements within the past year that were cancelled, expired, delayed, or modified. What was the primary reason for the changes? What, if any, were the secondary reasons?

    RESPONSE: During 2018 DEF terminated renewable energy purchase power agreements with Florida Power Development, Ridge Generating Station and US EcoGen Polk. The terminated Florida Power Development agreement was approved in Order PSC-2018-0240-PAA-EQ. The early termination is expected to save DEF customers between $38 and $59 million. The Ridge Generating Station agreement was also terminated early and that transaction was approved in Order PSC-2018-0532-PAA-EQ and is expected to save DEF customers between $30 to $35 million. The US EcoGen Polk biomass QF contract was terminated on October 3, 2018 by DEF due to default by US EcoGen Polk. As of the date of this submittal, US EcoGen Polk has filed for arbitration per their terminated QF Agreement and the arbitration process is underway administered by the American Arbitration Association.

32. Please provide the actual and projected annual output for all renewable resources on the Company's system, including utility-owned resources (firm, non-firm, and co-firing), purchases (firm, non-firm, and co-firing), and customer-owned generation, for the period 2019–2028.

RESPONSE: Please see the table below and tab 32 of the Excel file DEF 2019 SDR1 - Tables.xlsx.

Renewable Generation by Source

Renewable Source	Annual Renewable Generation (GWh)										
	Actual	Projected*									
	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Utility - Firm	26	249	865	1318	2205	2218	2605	2976	3340	3519	3708
Utility - Non-Firm	0	0	0	0	0	0	0	0	0	0	0
Utility - Co-Firing	0	0	0	0	0	0	0	0	0	0	0
Purchase – Firm	1012	617	619	617	617	617	619	617	617	617	619
Purchase - Non-Firm	329	138	149	316	630	942	1257	1562	1858	2007	2162
Purchase – Co-Firing	0	0	0	0	0	0	0	0	0	0	0
Customer-Owned (1)	51	43	125	208	289	338	368	401	438	479	523
Total	1418	1047	1758	2459	3741	4115	4849	5556	6255	6623	7012
Notes											
(1) Customer-Owned renewable generation for years 2019-2028 was estimated from DEF's forecast of net metering customers and 2018 was the actual amount of customer-owned renewable generation delivered to the DEF system for that year.											

33. Please complete the table below, providing a list of all of the Company's plant sites that are potential candidates for utility-scale (>2 MW) solar installations. As part of this response, please provide the plant site's name, approximate land area available for solar installations, potential installed capacity rating of a PV installation, and a description of any major obstacles that could affect utility-scale solar installations at any of these sites, such as land devoted to other uses or other requirements.

RESPONSE: Please see the table below and tab 33 of the Excel file DEF 2019 SDR1 - Tables.xlsx.

Candidate Sites – Solar

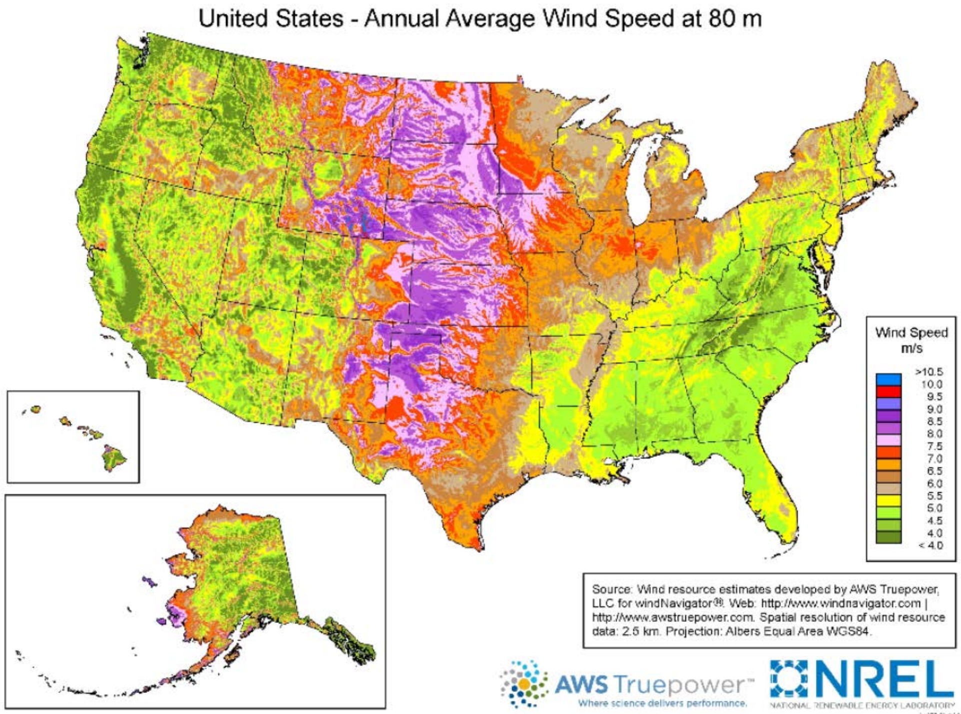
Plant Name	Land Available (Acres)	Installed Capacity (MW)	Potential Issues
Anclote	50	9	Wetlands, geotechnical problems, power grid interconnection costs, coastal area
Avon Park	60	10	Wetlands, geotechnical problems, species impacts
Crystal River	150	25	Wetlands, geotechnical problems, non-contiguous land, power grid interconnection not studied, impact to existing power plant, coastal area, species impacts
DeBary	800	74.9	Wetlands, native species habitat
Hines	150	25	Wetlands, geotechnical problems, native species habitat, non-contiguous land for solar, power grid interconnection not studied, impact to existing power plant, species impacts
Suwannee	60	10	Wetlands, geotechnical problems, archeological finds, native species habitat
Turner	15	2	Small site, non-contiguous land for solar, native species habitat
Higgins	75	12.7	Wetlands, geotechnical problems, power grid interconnection not studied and not in our territory, coastal area
Bartow	50	9	Wetlands, geotechnical problems, archeological finds, non-contiguous land for solar power grid interconnection not studied, impact to existing power plant, coastal area

34. Please complete the table below, providing a list of all of the Company's plant sites that are potential candidates for utility-scale wind installations. As part of this response, please provide the plant site's name, approximate land area available, potential installed capacity rating of a wind farm installation, and a description of any major obstacles that could affect utility-scale wind installations at any of these sites, such as land devoted to other uses or other requirements.

RESPONSE: Please see the table below and tab 34 of the Excel file DEF 2019 SDR1 - Tables.xlsx.

Candidate Sites - Wind

Plant Name	Land Available (Acres)	Installed Capacity (MW)	Potential Issues
Anclote	50-100	1.5-4.5	Hurricane design needs, neighborhood resistance, anchoring, coastal impact to metal life
Crystal River	50-100	1.5-4.5	Hurricane design needs, anchoring, coastal impact to metal life, impact to nuclear storage facility
Bartow	25-50	1.5	Hurricane design needs, neighborhood resistance, anchoring, coastal impact to metal life, FAA licensing/issues



35. Please describe any actions the Company engages in to encourage production of renewable energy within its service territory.

RESPONSE: DEF encourages renewable energy development and has continued to educate and engage with a wide range of Florida stakeholders to discuss renewable policy and the need for reliable, dependable, and cost-effective renewable energy including fuel diversity in Florida. Through DEF's development of utility-owned solar projects, DEF has engaged numerous renewable industry companies to work in Florida and continues to work with renewable project companies to acquire additional renewable facilities to advance DEF's renewable portfolio. In addition, DEF continues to educate audiences at various industry conferences, local community events, and via our web site on renewable energy resources and technologies. Using Company assets, displays, devices, and employees at these events, we are able to engage individual participants interested in encouraging the production of renewable energy within the state.

36. **[Investor-Owned Utilities Only]** Please discuss whether the Company has been approached by renewable energy generators during 2018 regarding constructing new renewable energy resources. If so, please provide the number and a description of the type of renewable generation represented.

    RESPONSE: DEF has officially recorded over 24 formal requests in 2018 from potential renewable energy providers and DEF has undertaken many more phone conversations. As the cost of solar PV technology continues to drop, there has been more interest from developers utilizing this technology. This interest can be seen in the dramatic increase in interconnection requests that DEF has received from solar PV projects. DEF, as of December 21, 2018 had over 6,100 MW in its interconnection queues. DEF continues to educate renewable energy generators on the potential QF structure and pricing of a renewable power purchase agreement. Most of the inquiries during 2018 were for solar photovoltaic projects, but there was also an inquiry about a biomass facility.

37. Does the Company consider solar PV to contribute to one or both seasonal peaks for reliability purposes? If so, please provide the percentage contribution and explain how the Company developed the value.

    RESPONSE: DEF has assigned a 57% equivalent summer capacity value to the DEF owned solar PV facilities in operation and for planned sites with the presumption that it will be designed with single axis tracking technology. Other technologies may result in other values such as DEF's DeBary Solar Plant in a fixed tilt configuration has been assigned a 45% equivalent summer capacity value. DEF assigns no winter peak capacity value to solar PV. These values were arrived at based on an analysis of data from models of anticipated PV performance correlated to DEF's load forecast. DEF recognizes that actual performance may differ from the model and that the correlation to peak load may change due to the amount of solar installed and changes in the load behavior. As a result, DEF expects that this value may be revised once the solar PV power plants are in service and there is demonstrated operating data.

38. Please identify whether a declining trend in costs of energy storage technologies has been observed by the Company.

    RESPONSE: Yes, Duke Energy has observed a declining trend in costs of energy storage, specifically the battery pack portion of the project cost.

39. Briefly discuss any progress in the development and commercialization of non-lithium battery storage technology the Company has observed in recent years.

    RESPONSE: While many non-lithium battery companies exist and have promising technologies, few have been successful at scaling to commercial size or produced to prove theoretical performance. Duke Energy continues to monitor several non-lithium battery storage technologies, such as flow batteries, but is currently focused on deploying proven, safe, and cost-effective lithium-ion technology.

40. Briefly discuss any considerations reviewed in determining the optimal positioning of energy storage technology in the Company's system. (e.g. Closer to/further from sources of load, generation, or transmission/distribution capabilities.)

    RESPONSE: Duke Energy considers energy storage to be another tool or resource to solve a host of problems across distribution, transmission, and generation. The optimal positioning is very project specific and is dependent upon the problem being solved. Ultimately, energy storage projects are compared to traditional tools or solutions to determine if energy storage is in fact the best solution. For example, Duke Energy is evaluating solar power plants with adjacent battery storage as well as investigating solutions to distribution reliability closer to the customer loads.

41. Please provide whether ratepayers have expressed interest in energy storage technologies. If so, how have their interests been addressed?

    RESPONSE: Customers (mainly commercial/industrial) have inquired about using energy storage in various forms. Usually it is for business continuity whether post-hurricane or temporary interruptions. Some customers have developed their own back up strategy and few have found battery storage external to their business as the best, economical solution to date. The customer is often looking for days of backup power which presently prices Li-ion technology out of consideration.

42. Please complete the table below, identifying all energy storage technologies that are currently either part of the Company's system portfolio or are part of a pilot program sponsored by the Company. As part of this response, please identify the project to which the energy storage technology is associated with, whether this project is a pilot program or not, the in-service date or pilot start date associated with the energy storage technology, and the maximum capacity output and maximum energy stored of/by the energy storage technology under normal operating conditions.

    RESPONSE: Please see the table below and tab 42 of the Excel file DEF 2019 SDR1 - Tables.xlsx.

Project Name	Pilot Program (Y/N)	In-Service/ Pilot Start Date	Max Capacity Output (MW)	Max Energy Stored (MHh)
USF Microgrid Energy Storage Pilot	Y	7/8/2018	0.250	0.475
Notes				
(Include Notes Here)				

43. Please identify and describe the objectives and methodologies of all energy storage pilot programs currently running or in development with an anticipated launch date within the next 10 years. If the Company is not currently participating in or developing energy storage pilot programs, has it considered doing so? If not, please explain.

a. Please discuss any pilot program results, addressing all anticipated benefits, risks, and operational limitations when such energy storage technology is applied on a utility scale (> 2 MW) to provide for either firm or non-firm capacity and energy.

<u>RESPONSE</u>: Duke Energy is currently developing energy storage projects as part of the 50 MW battery energy storage pilot program identified in the Settlement Agreement. We believe the program will prove that energy storage is a cost-effective tool to improve customer reliability, defer or eliminate traditional distribution investment, and improve operations of our universal solar assets. Since we are currently in the early development process, the benefits have not yet been realized.

b. Please provide a brief assessment of how these benefits, risks, and operational limitations may change over the next 10 years.

<u>RESPONSE</u>: DEF expects the current pilot program as well as future project future energy storage projects will help to better optimize the best blend of multiple use battery locations which may provide frequency management, capacity, and energy arbitrage values. These will include projects to mitigate intermittency from solar power and improve the coincidence between renewable generation and load. DEF also expects to better understand the benefits of energy storage as a key component of localized resiliency for locations as well as future uses of batteries to harden the local grids for counties and municipalities. As costs continue to drop on Li-ion batteries and perhaps other technologies provide additional paths to energy storage, storage will become a part of the myriad of tools DEF deploys to optimize grid resiliency and reduce certain transmission or distribution congestion/redundancy needs.

c. Please identify and describe any plans to periodically update the Commission on the status of your energy storage pilot programs.

<u>RESPONSE</u>: DEF plans to update the Commission on the status of our energy storage pilot programs during future Ten Year Site Plan filings and during any ad hoc requests made by the Commission.

44. If the Company utilizes non-firm generation sources in its system portfolio, please detail whether it currently utilizes or has considered utilizing energy storage technologies to provide firm capacity. If not, please explain.

    <u>RESPONSE</u>: To date, DEF has not utilized energy storage to provide firm capacity as it does not have such capacity installed. We will continue to review best fit locations for combining solar with storage to develop firm capacity.

45. Please identify and describe any programs you offer that allow your customers to contribute towards the funding of specific renewable projects, such as community solar programs.
    a. Please describe any such programs in development with an anticipated launch date within the next 10 years.

    <u>RESPONSE</u>: DEF is currently offering community solar through its Shared Solar Rider. This Rider is available to all Customers throughout the entire service area served by the Company on a first come first served basis subject. Customers can subscribe to individual blocks, of 50 kWh per month, of output from solar photovoltaic (PV) facilities owned and operated by Duke Energy Florida. Multiple subscriptions may be purchased up to a maximum of 25 blocks per month for residential, 150 blocks for commercial and 2,000 blocks for industrial customers. Application for service under this tariff is available to qualifying customers throughout the 5-year pilot period. The Company reserves the right to close the program to new applicants at any time during the 5-year availability period. The monthly subscription fee per block is $7.75. DEF is considering and studying new tariff structures that will improve the tariff and provide a greater benefit and cost efficiency to participants.

46. Please identify and discuss the Company's role in the research and development of utility power technologies. As part of this response, please describe any plans to implement the results of research and development into the Company's system portfolio and discuss how any anticipated benefits will affect your customers.

    <u>RESPONSE</u>: Duke Energy engages in research and development activities through many channels. The Company scans, monitors, and assesses emerging technology trends to inform the Company's long-term strategy on how these technologies may enable the

Company to meet evolving customer needs more efficiently. The Company is also a fully engaged member of the Electric Power Research Institute where we participate in most programs through over 300 advisory roles on an on-going basis.

47. **[Investor-Owned Utilities Only]** Provide, on a system-wide basis, the historical annual average as-available energy rate in the Company's service territory for the period 2009–2018. If the Company uses multiple areas for as-available energy rates, please provide a system-average rate as well. Also, provide the projected annual average as-available energy rate in the Company's service territory for the period 2019–2028.

<u>RESPONSE</u>: Please see the table below and tab 47 of the Excel file DEF 2019 SDR1 - Tables.xlsx.

As-Available Energy Rates

Year		As-Available Energy ($/MWh)	On-Peak Average ($/MWh)	Off-Peak Average ($/MWh)
Actual	2009	33.04	37.22	29.67
	2010	40.52	47.08	35.49
	2011	35.95	41.16	32.03
	2012	27.41	31.72	23.75
	2013	31.23	35.17	27.9
	2014	35.32	40.61	30.85
	2015	24.16	26.87	21.87
	2016	23.48	27.3	20.24
	2017	26.33	29.8	23.39
	2018	28.43	32.39	25.08
Projected	2019	24.57	26.06	23.31
	2020	22.68	24.31	21.3
	2021	20.75	22.05	19.65
	2022	18.72	19.55	18.03
	2023	17.22	17.53	16.97
	2024	19.8	20.52	19.19
	2025	23.73	24.93	22.7
	2026	26.06	26.23	25.92
	2027	29.81	31.17	28.66
	2028	32.12	33.9	30.61
Notes				
Historically, DEF has used its system marginal costs as practical estimates of its QF as-available rates. When the volume of anticipated as-available QF purchases were low in this scenario, this proxy estimate was reasonable. However, with the large amount of solar projects in the various DEF interconnection queues, a greater volume of QF as-available purchases must be forecasted for customer protection. It is also important to note that current estimates are only valid and effective as of May 1, 2019 due to the steady QF activity. Along with these larger amounts of QF generators contributing to DEF's as-available block size, it is also anticipated that at some point DEF will have increasing amounts of time when required DEF system generation along with potential QF generation will exceed the forecasted DEF load levels and that excess energy may not have been fully captured in the estimates herein. These factors have contributed to DEF further refining its estimate of QF future energy payment rates as reflected above.				

48. Please complete the following table detailing planned unit additions, including information on capacity and in-service dates. Please include only planned conventional units with an in-service date past January 1, 2018. For each planned unit, provide the date of the Commission's Determination of Need and Power Plant Siting Act certification (if applicable), and the anticipated in-service date.

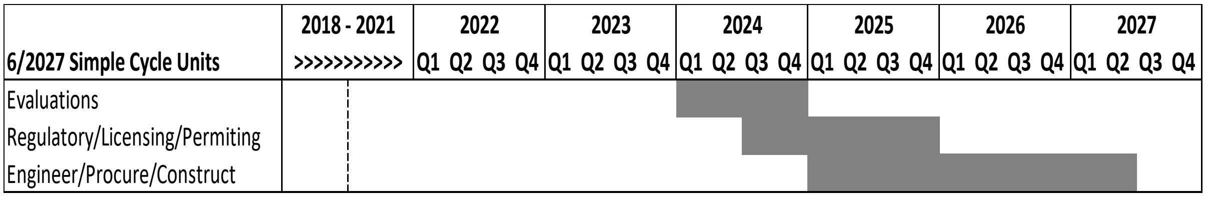
RESPONSE: Please see the table below and tab 48 of the Excel file DEF 2019 SDR1 - Tables.xlsx.

Planned Unit Additions

Generating Unit Name	Summer Capacity (MW)	Certification Dates (if Applicable)		In-Service Date
		Need Approved (Commission)	PPSA Certified	
Nuclear Unit Additions				
Combustion Turbine Unit Additions				
Unknown	218	Not Required	Not Required	6/1/2027
Unknown	218	Not Required	Not Required	6/1/2027
Combined Cycle Unit Additions				
Steam Turbine Unit Additions				
Notes				
(Include Notes Here)				

49. For each of the planned generating units contained in the Company's 2019 TYSP, please discuss the "drop dead" date for a decision on whether or not to construct each unit. Provide a time line for the construction of each unit, including regulatory approval, and final decision point.

RESPONSE: In the Duke Energy Florida April 2019 Ten-Year Site Plan, the in-service date for the two future simple cycle units were projected for 6/2027. A "drop dead" decision date to proceed with the 6/2027 or later Simple Cycle Units would typically occur 24-30 months prior to the in-service date, or in the planning years 2025 for the three units. The major components of the 'drop dead' date for the simple cycle schedule for the three 6/2027 CTs are shown below:



DEF typically develops solar plants within a 12 - 36 month schedule and may develop these projects in groups or "tranches". As a result, a single decision date that is tied to investments in any grouping of projects may occur between nine and 36 months from service.

50. Please provide an estimate of the revenue requirements of the Company based upon the 2019 TYSP's planned generating units.

RESPONSE: Please see the table below.

$K	2019 TYSP Revenue Requirements
	Optimal Plan
2019	4,620,874
2020	4,761,878
2021	4,840,156
2022	5,158,895
2023	5,206,869
2024	5,215,956
2025	5,363,891
2026	5,572,243
2027	5,882,954
2028	6,146,446

51. For each of the planned generating units contained in the Company's 2019 TYSP, please identify the next best alternative that was rejected for each unit. Provide information similar to Schedule 9 regarding each of the next best alternative unit(s). As part of this response, please also provide the additional revenue requirement that would have been associated with the next best alternative compared to the planned unit.

RESPONSE: Please see the tables below on information regarding Schedule 9 and Additional Revenue Requirements.

DUKE ENERGY FLORIDA

SCHEDULE 9
STATUS REPORT AND SPECIFICATIONS OF PROPOSED GENERATING FACILITIES
AS OF JANUARY 1, 2019

(1)	Plant Name and Unit Number:		**Undesignated Combined Cycle**
(2)	Capacity		
	a. Summer:		1241
	b. Winter:		1366
(3)	Technology Type:		COMBINED CYCLE
(4)	Anticipated Construction Timing		
	a. Field construction start date:		1/2024
	b. Commercial in-service date:		6/2027
(5)	Fuel		
	a. Primary fuel:		NATURAL GAS
	b. Alternate fuel:		DISTILLATE FUEL OIL
(6)	Air Pollution Control Strategy:		SCR and CO Catalyst
(7)	Cooling Method:		Cooling Tower
(8)	Total Site Area:		UNKNOWN ACRES
(9)	Construction Status:		PLANNED
(10)	Certification Status:		PLANNED
(11)	Status with Federal Agencies:		PLANNED
(12)	Projected Unit Performance Data		
	a. Planned Outage Factor (POF):		6.90 %
	b. Forced Outage Factor (FOF):		4.60 %
	c. Equivalent Availability Factor (EAF):		88.82 %
	d. Resulting Capacity Factor (%):		85.7 %
	e. Average Net Operating Heat Rate (ANOHR):		6,434 BTU/kWh
(13)	Projected Unit Financial Data		
	a. Book Life (Years):		35
	b. Total Installed Cost (In-service year $/kW):		1201
	c. Direct Construction Cost ($/kW):	($2019)	1020
	d. AFUDC Amount ($/kW):		68
	e. Escalation ($/kW):		113
	f. Fixed O&M ($/kW-yr):	($2019)	4.42
	g. Variable O&M ($/MWh):	($2019)	3.08
	h. K Factor:		NO CALCULATION

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

	2019 TYSP Revenue Requirements		Suboptimal - Optimal
CPVRR $K	$38,784,995	$38,941,904	$156,909
Nominal $K	Optimal Plan 2 2027 CTs	Suboptimal Plan 2027 CC	Difference
2019	4,620,874	4,620,874	-
2020	4,761,878	4,761,878	-
2021	4,840,156	4,840,156	-
2022	5,158,895	5,158,895	-
2023	5,206,869	5,206,869	-
2024	5,215,956	5,215,956	-
2025	5,363,891	5,363,891	-
2026	5,572,243	5,572,243	-
2027	5,882,954	6,018,177	135,223
2028	6,146,446	6,293,684	147,238

52. For each existing and planned unit on the Company's system, provide the following data based upon historic data from 2018 and projected capacity factor values for the period 2019–2028. Please complete the tables below and provide an electronic copy in Microsoft Excel format.

<u>**RESPONSE**</u>**:** Please see the table below and tab 52 of the Excel file DEF 2019 SDR1 - Tables.xlsx.

Projected Unit Information – Capacity Factor (%)

Plant	Unit #	Unit Type	Fuel Type	Actual 2018	Projected 2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Anclote	1	Steam	Gas	33.7	10.8	6.7	7.2	8.0	7.6	8.7	8.1	9.7	9.6	9.6
Anclote	2	Steam	Gas	26.8	8.6	7.1	8.9	9.1	8.9	10.4	8.9	8.6	10.8	9.6
Crystal River	1	Steam	Coal	3.4	-	-	-	-	-	-	-	-	-	-
Crystal River	2	Steam	Coal	18.3	-	-	-	-	-	-	-	-	-	-
Crystal River	4	Steam	Coal	57.0	44.1	24.2	23.4	18.1	22.3	25.3	28.1	28.0	30.5	26.1
Crystal River	5	Steam	Coal	63.9	41.6	31.3	25.6	25.7	27.5	33.2	30.9	34.5	30.5	36.4
Hines Energy Complex	1~4	Combined Cycle	Gas	69.4	63.8	60.2	60.0	56.7	54.6	54.5	56.1	54.6	53.5	54.5
Bartow CC	4	Combined Cycle	Gas	67.2	57.8	78.7	77.1	73.4	74.1	70.8	70.1	65.9	68.7	68.6
Tiger Bay	1	Combined Cycle	Gas	59.9	64.0	62.2	69.0	70.7	72.9	63.6	62.7	65.7	68.0	64.7
University of Florida	1	Gas Turbine	Gas	80.5	87.5	89.5	89.4	89.4	89.4	89.4	79.2	89.4	89.4	76.3
Citrus CC	1~2	Combined Cycle	Gas	-	83.7	87.3	90.4	90.7	87.4	87.4	82.1	86.2	85.8	85.3
Avon Park	1~2	Gas Turbine	Gas Oil	0.2	3.5	0.8	-	-	-	-	-	-	-	-
Bartow Peaker	1~4	Gas Turbine	Gas Oil	1.4	0.2	0.3	0.2	0.1	0.1	0.6	1.0	0.7	1.4	1.8
Bayboro	1~4	Gas Turbine	Oil	0.4	0.1	0.2	0.2	0.1	0.1	0.5	1.0	0.7	1.6	1.9
DeBary	1~10	Gas Turbine	Gas Oil	0.8	0.3	0.3	0.3	0.2	0.2	0.8	1.1	0.9	1.7	2.3
Higgins	1~4	Gas Turbine	Gas Oil	2.4	0.4	0.0	-	-	-	-	-	-	-	-
Intercession City	1~14	Gas Turbine	Gas Oil	5.2	0.5	0.4	0.5	0.5	0.4	1.3	1.5	1.4	2.4	2.5
Suwannee Peaker	1~3	Gas Turbine	Gas Oil	2.4	0.4	0.4	0.4	0.3	0.2	0.8	1.1	0.9	1.5	1.5
Osprey CC	1	Combined Cycle	Gas	37.7	35.5	32.5	38.5	41.3	43.1	76.3	74.5	70.4	69.0	71.6
Generic CTs	1~3	Gas Turbine	Gas	na	-	-	-	-	-	-	-	-	17.5	11.1
Solar	1	PV		16.9	27.7	28.4	28.5	29.2	29.1	29.2	29.3	29.4	29.4	29.4

53. For each existing unit on the Company's system, please provide the planned retirement date. If the Company does not have a planned retirement date for a unit, please provide an estimated lifespan for units of that type and a non-binding estimate of the retirement date for the unit.

RESPONSE: DEF does not strictly maintain a retirement schedule for each unit on the DEF system, but periodically evaluates each unit on a case by case basis, taking into account changes in many factors including unit dispatch (history and projections of starts and capacity factor), changes in upcoming maintenance, the anticipated impact of final or proposed environmental regulations, potential transmission impacts, and availability of parts and vendor maintenance support. DEF uses the most recently approved depreciation schedules as a guideline. The table below presents the current depreciation schedules.

PLANT NAME	UNIT NO.	UNIT TYPE	FUEL PRI.	NET CAPABILITY SUMMER MW	IN-SERVICE YEAR	CURRENT APPROVED CAPITAL RECOVERY DATE	LIFESPAN IN YEARS
STEAM UNITS							
CRYSTAL RIVER- SOUTH	1, 2	ST	BIT	766	1966	2020	54
CRYSTAL RIVER - NORTH	4, 5	ST	BIT	1,422	1982	2042	60
ANCLOTE	1, 2	ST	RFO	1,013	1974	2024	50
COMBINED-CYCLE UNITS							
BARTOW	4	CC	NG	1,080	2009	2044	35
HINES ENERGY COMPLEX	1	CC	NG	462	1999	2034	35
HINES ENERGY COMPLEX	2	CC	NG	490	2003	2038	35
HINES ENERGY COMPLEX	3	CC	NG	488	2005	2040	35
HINES ENERGY COMPLEX	4	CC	NG	472	2007	2042	35
TIGER BAY	1	CC	NG	205	1995	2038	43
OSPREY ENERGY CENTER	1	CC	NG	574	2004	2042	38
SIMPLE CYCLE COMBUSTION TURBINES							
AERODERIVATIVE UNITS							
AVON PARK	P1	GT	NG	24	1968	2016	48
AVON PARK	P2	GT	DFO	24	1968	2016	48
BAYBORO	P1-P4	GT	DFO	174	1973	2029	56
HIGGINS	P1-P4	GT	NG	107	1969	2016	47
INTERCESSION CITY	P1-P6	GT	DFO	282	1974	2020	46
SUWANNEE RIVER	P1, P3	GT	NG	103	1980	2024	44
SUWANNEE RIVER	P2	GT	DFO	51	1980	2024	44
FRAME UNITS							
BARTOW	P1, P3	GT	DFO	85	1972	2027	55
BARTOW	P2, P4	GT	NG	86	1972	2027	55
DEBARY	P2-P6	GT	DFO	249	1975	2020	45
DEBARY	P7-P9	GT	NG	236	1992	2023	31
DEBARY	P10	GT	DFO	79	1992	2023	31
INTERCESSION CITY	P11 **	GT	DFO	143	1997	2022	25
INTERCESSION CITY	P7-P10	GT	NG	328	1993	2031	38
INTERCESSION CITY	P12-P14	GT	NG	229	2000	2036	36
UNIV. OF FLA.	P1	GT	NG	46	1993	2033	40

54. Please complete the table below, providing a list of all of the Company's steam units that are potential candidates for repowering to operation as Combined Cycle units. As part of this response, please provide the unit's current fuel type, summer capacity rating, in-service date, and what potential conversion, fuel-switching, or repowering would be most applicable. Also include a description of any potential issues that could affect repowering efforts at any of these sites, related to such things as unit age, land availability, or other requirements.

RESPONSE: Please see the table below and tab 54 of the Excel file DEF 2019 SDR1 - Tables.xlsx.

Repowering Candidate Units – Steam

Plant Name	Fuel Type	Summer Capacity (MW)	In-Service Date	Potential Conversion	Potential Issues
Anclote	NG	498	10/74	CC	Project Development
Anclote	NG	505	10/78	CC	Project Development
Crystal River	BIT	712	12/82	CC/IGCC	Project Development
Crystal River	BIT	710	10/84	CC/IGCC	Project Development
Notes					
(Include Notes Here)					

55. Please identify each of the Company's existing (as of December 31, 2018) and planned (between 2019–2028) power purchase contracts, including firm capacity imports reflected in Schedule 7 of the Company's 2019 TYSP. Provide the seller, the term of the contract, amount of seasonal capacity purchased, the primary fuel (if applicable, such as with a unit purchase), whether it is included in the Utility's firm peak capacity, and a description of the source of the purchase (such as the name of the unit in a unit purchase).

<u>RESPONSE</u>: Please see the table below and tab 55 of the Excel file DEF 2019 SDR1 - Tables.xlsx.

Existing Purchased Power Agreements

Seller	Contract Term		Contract Capacity (MW)		Capacity Factor (%)	Primary Fuel (if any)	Firm Capacity	Description
	Begins	Ends	Summer	Winter				
Shady Hills Power Company	4/1/2007	4/30/2024	480	522	15.8%	NG	Yes	CT
Southern Power	6/1/2016	5/31/2021	424	424	43.7%	NG	Yes	CC - Franklin
Northern Star Generation	6/1/95	12/31/25	104	104	93.0%	GAS	Yes	GT - Orange Cogen Facility
Northern Star Generation	1/1/14	12/31/23	115	115	102.0%	GAS	Yes	CT - Orlando Cogen Facility
Northern Star Generation	7/1/94	8/31/24	115	115	94.0%	GAS	Yes	GT - Mulberry Cogen Facility
Northern Star Generation	6/1/12	5/31/27	640	681	20.3%	GAS	Yes	GT- Vandolah Facility
Notes								

Planned Purchased Power Agreements

Seller	Contract Term		Contract Capacity (MW)		Capacity Factor (%)	Primary Fuel (if any)	Firm Capacity	Description
	Begins	Ends	Summer	Winter				
N/A								
Notes								
(Include Notes Here)								

56. Please identify each of the Company's existing (as of December 31, 2018) and planned (between 2019–2028) power sales, including firm capacity exports reflected in Schedule 7 of the Company's 2019 TYSP. Provide the purchaser, the term of the contract, amount of seasonal capacity sold, the primary fuel (if applicable, such as with a unit purchase), whether it is included in the Utility's firm peak demand, and a description of the sale (such as the name of the unit in a unit purchase).

<u>RESPONSE</u>: Please see the table below and tab 56 of the Excel file DEF 2019 SDR1 - Tables.xlsx.

Existing Power Sales

Purchaser	Contract Term		Contract Capacity (MW)		Primary Fuel (if any)	Firm Demand	Description
	Begins	Ends	Summer	Winter			
Seminole	6/1/2016	12/31/2024	200	200	Nat Gas	Yes	Partial Req'ts
Seminole	1/1/2014	12/31/2018	50	50	System	Yes	Partial Req'ts
Seminole	1/1/2014	12/31/2020	150	150	System	Yes	Partial Req'ts
Seminole	6/1/2017	12/31/2020	100	0	System	Yes	Partial Req'ts
Seminole	1/1/2014	12/31/2020	0	600	System	Yes	Partial Req'ts
Seminole	6/1/1987	Evergreen	0.014	0.014	System	Yes	Partial Req'ts
Homestead	1/1/2007	12/31/2019	25	25	System	Yes	Partial Req'ts
Homestead	1/1/2007	12/31/2019	15	15	System	Yes	Partial Req'ts
New Smyrna Beach	1/1/2013	12/31/2018	30	30	System	Yes	Partial Req'ts
Reedy Creek	1/1/2016	12/31/2020	129	81	Nat Gas	Yes	Partial Req'ts
Reedy Creek	1/27/2017	6/30/2019	53	53	Nat Gas	Yes	Partial Req'ts
Chattahoochee	1/1/2016	12/31/2020	6	4	System	Yes	Full Req'ts
Mount Dora	1/1/2013	12/31/2020	21	23	System	Yes	Full Req'ts
Williston	1/1/2013	12/31/2020	8	9	System	Yes	Full Req'ts
Notes							
(Include Notes Here)							

Planned Power Sales

Purchaser	Contract Term		Contract Capacity (MW)		Primary Fuel (if any)	Firm Demand	Description
	Begins	Ends	Summer	Winter			
Seminole	1/1/2021	3/31/2027	0	50	System	Yes	Partial Req'ts
Seminole	1/1/2021	12/31/2030	400	401	System	Yes	Partial Req'ts
Seminole	1/1/2021	12/31/2035	50	50	System	Yes	Partial Req'ts
Notes							
(Include Notes Here)							

57. Please list and discuss any long-term power sale or purchase agreements within the past year that were cancelled, expired, or modified.

<u>**RESPONSE**</u>**:** During 2018 DEF terminated renewable energy purchase power agreements with Florida Power Development, Ridge Generating Station and US EcoGen Polk. The Florida Power Development agreement was bought out early and approved in Order PSC-2018-0240-PAA-EQ. That buyout is expected to save DEF customers between $38 and $59 million. The Ridge Generating Station agreement was also bought out early and that buyout was approved in Order PSC-2018-0532-PAA-EQ and is expected to save DEF customers between $30 to $35 million. The US EcoGen Polk agreement was terminated on October 3, 2018 by DEF due to US EcoGen Polk's failure to satisfy the financing requirements of the agreement, because US EcoGen Polk provided misleading or false representations or warranty regarding its alleged satisfaction of the financing

requirements of the agreement and because US EcoGen Polk failed to provide their financing documents when requested by DEF. US EcoGen Polk disputes DEF's claims and has filed for arbitration.

58. Please provide a list of all proposed transmission lines in the planning period that require certification under the Transmission Line Siting Act. Please also include those that have been approved, but are not yet in-service, when completing the table below.

<u>RESPONSE</u>: DEF does not presently have any proposed transmission lines in the planning period that require certification under the Transmission Line Siting Act. Please see the table below and tab 58 of the Excel file DEF 2019 SDR1 - Tables.xlsx.

Transmission Projects Requiring TLSA Approval

Transmission Line	Line Length	Nominal Voltage	Date Need Approved	Date TLSA Certified	In-Service Date
	(Miles)	(kV)			
N/A					
Notes					
The DEF Transmission projects in Schedule 10 or other DEF projects do not require TLSA approval.					

<u>Environmental</u>

59. Provide a narrative explaining the impact of any existing environmental regulations relating to air emissions and water quality or waste issues on the Company's system during the 2018 period. As part of your narrative, please discuss the potential for existing environmental regulations to impact unit dispatch, curtailments, or retirements during the 2019–2028 period.

<u>RESPONSE</u>:
Anclote Unit 1 was derated on seven occasions between August 21, 2018 and September 6, 2018 as a result of actions taken to comply with the Manatee Protection Plan associated with the Anclote National Pollutant Discharge Elimination System (NPDES) permit. The Crystal River Units 1 and 2 air emissions are governed by a permit that requires the units to comply with opacity emission limits. These units must also comply with more restrictive Best Available Retrofit Technology (BART) for opacity and particulate matter (PM). There were no derates of these units in 2018 to maintain compliance with the PM limit. CR Units 1 and 2 were retired from service on December 31, 2018 in coordination with the 2018 Citrus Combined Cycle operations.

60. Please complete the table below, providing actual and projected amounts of regulated air pollutants and carbon dioxide emitted, on an annual and per megawatt-hour basis, by the

Company's generation fleet. Please also provide an electronic copy of the completed table in Microsoft Excel format.

RESPONSE: Please see the table below and tab 60 of the Excel file DEF 2019 SDR1 - Tables.xlsx.

Emissions of Registered Air Pollutants & CO2

Year		SOX		NOX		Mercury		Particulates		CO2	
		lb/MWh	Tons	lb/MWh	Tons	lb/MWh	Tons	lb/MWh	Tons	lb/MWh	Tons
Actual	2009	4.4	79,685	1.3	23,891	0.000010	0.18	0.14	2,722	1202	21,739,872
	2010	2.5	47,264	0.8	15,999	0.000010	0.19	0.15	2,789	1325	25,421,640
	2011	1.6	28,529	0.7	11,271	0.000005	0.08	0.12	2,238	1358	23,526,029
	2012	1.5	27,259	0.6	11,233	0.000004	0.07	0.15	2,582	1277	22,719,631
	2013	1.7	30,667	0.6	11,174	0.000005	0.08	0.13	2,326	1288	22,722,624
	2014	1.8	32,608	0.8	13,888	0.000005	0.09	0.12	2,237	1351	24,463,235
	2015	1.4	24,885	0.7	12,865	0.000004	0.10	0.10	1,859	1280	23,354,225
	2016	0.7	12,173	0.7	11,711	0.0000014	0.03	0.09	1,605	1275	22,421,548
	2017	0.7	12,993	0.5	9,591	0.0000016	0.03	0.09	1,622	1294	23,366,605
	2018	0.5	10,830	0.4	9,233	0.0000013	0.03	0.08	1,861	1,044	23,087,717
Projected	2019	0.2	4,518	0.2	4,195	0.000003	0.05	0.09	1,944	1,025	19,701,405
	2020	0.2	3,111	0.2	3,835	0.000002	0.04	0.09	1,963	936	18,311,430
	2021	0.1	2,758	0.2	3,633	0.000002	0.03	0.09	1,978	913	18,103,800
	2022	0.1	2,499	0.2	3,445	0.000001	0.03	0.09	2,003	886	17,507,983
	2023	0.1	2,823	0.2	3,537	0.000002	0.03	0.09	2,001	901	17,680,362
	2024	0.2	3,304	0.2	3,959	0.000002	0.04	0.09	2,017	910	18,718,286
	2025	0.2	3,413	0.2	4,307	0.000002	0.04	0.09	2,013	905	18,744,486
	2026	0.2	3,521	0.2	4,073	0.000002	0.04	0.09	2,028	905	18,948,002
	2027	0.2	3,444	0.2	4,458	0.000002	0.04	0.09	2,043	905	19,288,071
	2028	0.2	3,501	0.2	4,526	0.000002	0.04	0.09	2,066	903	19,457,271
Notes											
(Include Notes Here)											

61. For the U.S. Environmental Protection Agency's (EPA's) Mercury and Air Toxics Standards (MATS) Rule:
    a. Will your Company be materially affected by the rule?
    b. What compliance strategy does the Company anticipate employing for the rule?
    c. If the strategy has not been completed, what is the Company's timeline for completing the compliance strategy?

d. Will there be any regulatory approvals needed for implementing this compliance strategy? How will this affect the timeline?
e. Does the Company anticipate asking for cost recovery for any expenses related to this rule? Please complete the following chart regarding MATS-related costs:

If the answer to any of the above questions is not available, please explain why.

RESPONSE:
a. Yes
b. DEF has provided its compliance strategy for MATS in the Integrated Clean Air Compliance Plan submitted to the Commission on March 29, 2019 in Docket 20190007-EI.
c. The compliance strategy for MATS has been implemented.
d. No further regulatory approvals are required.
e. Please see the table below and tab 61 of the Excel file DEF 2019 SDR1 - Tables.xlsx.

Year	Estimated Cost of Mercury and Air Toxics Standards (MATS) Rule Impacts (2019 $ millions)			
	Capital Costs	O&M Costs	Fuel Costs	Total Costs
2019	0	1	0	1
2020	0	1	0	1
2021	0	1	0	1
2022	0	1	0	1
2023	0	1	0	1
2024	0	1	0	1
2025	0	1	0	1
2026	0	1	0	1
2027	0	1	0	1
2028	0	1	0	1
Notes				
MATS compliance costs will decrease after retirement of Crystal River Units 1 and 2, expected in late 2018.				

If the answer to any of the above questions is not available, please explain why that is so.

RESPONSE: N/A

62. For the U.S. EPA's Cross-State Air Pollution Rule (CSAPR):
    a. Will your Company be materially affected by the rule?
    b. What compliance strategy does the Company anticipate employing for the rule?
    c. If the strategy has not been completed, what is the Company's timeline for completing the compliance strategy?
    d. Will there be any regulatory approvals needed for implementing this compliance strategy? How will this affect the timeline?
    e. Does the Company anticipate asking for cost recovery for any expenses related to this rule? Please complete the following chart regarding CSAPR-related costs:

If the answer to any of the above questions is not available, please explain why.

<u>RESPONSE</u>:

a. No
b. DEF sources are not subject to CSAPR.
c. N/A
d. N/A
e. Please see the table below and tab 62 of the Excel file DEF 2019 SDR1 - Tables.xlsx.

Year	Estimated Cross-State Air Pollution Rule (CSAPR) Rule Impacts (2019 $ millions)			
	Capital Costs	O&M Costs	Fuel Costs	Total Costs
2019	0	0	0	0
2020	0	0	0	0
2021	0	0	0	0
2022	0	0	0	0
2023	0	0	0	0
2024	0	0	0	0
2025	0	0	0	0
2026	0	0	0	0
2027	0	0	0	0
2028	0	0	0	0
Notes				
(Include Notes Here)				

If the answer to any of the above questions is not available, please explain why that is so.

<u>RESPONSE</u>: N/A

63. For the U.S. EPA’s Cooling Water Intake Structures (CWIS) Rule:
    a. Will your Company be materially affected by the rule?
    b. What compliance strategy does the Company anticipate employing for the rule?
    c. If the strategy has not been completed, what is the Company’s timeline for completing the compliance strategy?
    d. Will there be any regulatory approvals needed for implementing this compliance strategy? How will this affect the timeline?
    e. Does the Company anticipate asking for cost recovery for any expenses related to this rule? Please complete the following chart regarding CWIS-related costs:

If the answer to any of the above questions is not available, please explain why.

RESPONSE:

a. Yes.

b. DEF’s Crystal River Units 1, 2, 4, and 5, Anclote Units 1 and 2, Bartow Combined Cycle and new Citrus County Combined Cycle station subject to 316(b) regulations.
The long-term compliance plan for Crystal River Units 1 and 2 (“CR South”) is the retirement of those units when the Citrus County Combined Cycle units begin commercial operation in 2018. CR Units 1 and 2 were retired from service on December 31, 2018. A portion of the Crystal River South circulating water pumps will continue to be operated beyond 2018 until modifications are implemented to the Crystal River Units 4 and 5 makeup water system in the 2020 timeframe.

   The 316(b) compliance plan for Crystal River Units 4 and 5 (“Crystal River North”, “CR North”, or “CRN”) involves interconnection to the new Citrus County Combined Cycle (“Citrus CC”) cooling tower blowdown system to supply makeup water to the CR North cooling towers. Recycling blowdown from Citrus CC will eliminate the need for a separate CWIS for Crystal River North thereby reducing cooling water intake withdrawals and associated impingement and entrainment loads. The existing CR North cooling water intake structure will be modified to serve as a backup system for operational conditions in which the required cooling tower makeup flow could not be supplied from Citrus CC. Major components of the project scope include the installation of new piping and valves to extend the Citrus CC discharge pipe to the CR North intake channel

   Site specific strategic plans, studies, and implementation plans are under development for Anclote and Bartow stations to ensure compliance with all applicable requirements of the rule.

   The Citrus County Combined Cycle cooling water intake structure was designed to be fully compliant with 316(b) rule requirements upon start-up.

c. CR Units 1 and 2 were retired from service on December 31, 2018. Work at Crystal River Units 4 and 5 is expected to be complete by the end of 2020. The Citrus County

Combined Cycle cooling water intake structure was designed to comply with the 316(b) rule; and has operated within compliance since the units began operation in 2018. For Bartow and Anclote, DEF will submit study results to FDEP in mid-2020; DEF will have five years from the issuance of the next National Pollutant Discharge Elimination System (NPDES) permit (issuance expected in 2021) to begin implementation of the 316(b) rule compliance strategy.

d. The Florida Department of Environmental Protection (FDEP) and the EPA will need to approve the compliance strategy through an NPDES permit renewal of modification prior to implementation.

e. Please see the table below and tab 63 of the Excel file DEF 2019 SDR1 - Tables.xlsx.

DEF anticipates O&M costs for studies at applicable facilities. DEF anticipates capital costs for implementation of the compliance strategy, but all specific compliance measures and associated costs have not been identified.

Year	Estimated Cost of Cooling Water Intake Structures Rule (CWIS) Rule Impacts (2019 $ millions)			
	Capital Costs	O&M Costs	Fuel Costs	Total Costs
2019	4	1	0	5
2020	10	1	0	11
2021	TBD	TBD	0	TBD
2022	TBD	TBD	0	TBD
2023	TBD	TBD	0	TBD
2024	TBD	TBD	0	TBD
2025	TBD	TBD	0	TBD
2026	TBD	TBD	0	TBD
2027	TBD	TBD	0	TBD
2028	TBD	TBD	1	TBD
Notes				
(Include Notes Here)				

If the answer to any of the above questions is not available, please explain why that is so.

<u>RESPONSE</u>: N/A

64. For the U.S. EPA's Coal Combustion Residuals Rule (CCR), both for classification of coal ash as a "Non-Hazardous Waste" and as a "Special Waste."
    a. Will your Company be materially affected by the rule?
    b. What compliance strategy does the Company anticipate employing for the rule?
    c. If the strategy has not been completed, what is the Company's timeline for completing the compliance strategy?
    d. Will there be any regulatory approvals needed for implementing this compliance strategy? How will this affect the timeline?
    e. Does the Company anticipate asking for cost recovery for any expenses related to this rule? Please complete the following chart regarding CCR-related costs:

If the answer to any of the above questions is not available, please explain why.

RESPONSE:

a. Yes; however, further evaluation is required to determine the extent to which DEF will be affected by the rule.

b. DEF continues to evaluate the CCR rule to determine operating and cost impacts. The full extent of compliance activities and associated costs cannot be determined until further analysis and assessment, including CCR well data analysis, is complete. As these analyses and assessments are completed and additional compliance activities and costs become known, DEF will update the Commission and provide the costs for recovery, as appropriate, in later ECRC filings.

c. The strategy is in place. Additional information is being gathered to determine the compliance plan and timeline for the Crystal River landfill.

d. DEF does not anticipate the need for regulatory approvals to implement the compliance strategy.

e. Please see the table below and tab 64 of the Excel file DEF 2019 SDR1 - Tables.xlsx.

   DEF anticipates O&M costs for monitoring plans at applicable facilities. DEF anticipates capital costs for implementation of the compliance strategy, but specific compliance measures and associated costs have not been identified.

Year	Estimated Coal Combustion Residuals Rule (CCR) Impacts (2019 $ millions)			
	Capital Costs	O&M Costs	Fuel Costs	Total Costs
2019	0.4	0.25	0	0.65
2020	TBD	0.25	0	0.25+ Capital
2021	TBD	0.25	0	0.25+ Capital
2022	TBD	0.25	0	0.25+ Capital
2023	TBD	0.25	0	0.25+ Capital
2024	TBD	0.25	0	0.25+ Capital
2025	TBD	0.25	0	0.25+ Capital
2026	TBD	0.25	0	0.25+ Capital
2027	TBD	0.25	0	0.25+ Capital
2028	TBD	0.25	0	0.25+ Capital
Notes				
(Include Notes Here)				

65. For the U.S. EPA's Standards of Performance for Greenhouse Gas Emissions for New Stationary Sources: Electric Utility Generating Units Rule:
    a. Will your Company be materially affected by the rule?
    b. What compliance strategy does the Company anticipate employing for the rule?
    c. If the strategy has not been completed, what is the Company's timeline for completing the compliance strategy?
    d. Will there be any regulatory approvals needed for implementing this compliance strategy? How will this affect the timeline?
    e. Does the Company anticipate asking for cost recovery for any expenses related to this rule? Please complete the following chart regarding costs:

    If the answer to any of the above questions is not available, please explain why.

RESPONSE:

a. The EPA combined several standards and issued the final rule as the "Standards of Performance for Greenhouse Gas Emissions from New, Modified and Reconstructed Stationary Sources: Electric Utility Generating Units" (CO_2 NSPS). The new units affected by these standards will meet the compliance requirements outlined in the rule and DEF has not identified any units potentially affected as "Modified" or "Reconstructed" stationary sources. As such, DEF does not anticipate any reliability impacts of this rule. On March 27, 2017 President Trump signed an Executive Order (EO) entitled "Promoting Energy Independence and Economic Growth." The EO directs federal agencies to "immediately review existing regulations that potentially burden the development or use of domestically produced energy resources and appropriately suspend, revise, or rescind those that unduly burden the development of domestic energy resources."

The EO specifically directs the EPA to review the Standards of Performance for Greenhouse Gas Emissions from New, Modified, and Reconstructed Stationary Sources: Electric Utility Generating Units Rule (among other rules) and determine whether to suspend, revise, or rescind those the rule.

In response to the EO, the Department of Justice filed motions with the D.C. Circuit Court to stay the litigation of the CO2 NSPS rules, along with the Clean Power Plan for existing sources, while each is reviewed by EPA. The CO2 NSPS will remain in effect pending the outcome of EPA's review.

b. DEF will ensure that all new generating facilities comply with new standards and will monitor maintenance and compliance activities related to existing facilities that could potentially result in the facilities being identified as "Modified" or "Reconstructed" stationary sources under the rule.
c. N/A
d. There are no specific regulatory approvals identified as associated with compliance with this rule.
e. RESPONSE: None anticipated. Please see table below and tab 65 of the Excel file DEF 2019 SDR1 - Tables.xlsx.

Year	Estimated Cost of Standards of Performance for Greenhouse Gas Emissions Rule for New Sources Impacts (2019 $ millions)			
	Capital Costs	O&M Costs	Fuel Costs	Total Costs
2019	0	0	0	0
2020	0	0	0	0
2021	0	0	0	0
2022	0	0	0	0
2023	0	0	0	0
2024	0	0	0	0
2025	0	0	0	0
2026	0	0	0	0
2027	0	0	0	0
2028	0	0	0	0
Notes				
(Include Notes Here)				

If the answer to any of the above questions is not available, please explain why that is so.

RESPONSE: N/A

66. Please identify, for each unit affected by one or more of EPA’s rules, what the impact is for each rule, including; unit retirement, curtailment, installation of additional emissions controls, fuel switching, or other impacts identified by the Company. As part of this response, please also indicate the unit’s name, type, fuel type, and net summer generating capacity. Please complete the table below and provide an electronic copy in Microsoft Excel format.

RESPONSE:

DEF has provided its compliance strategy for MATS, CSAPR/CAIR, and the Regional Haze Rule in the Integrated Clean Air Compliance Plan submitted to the Commission on March 29, 2019 in Docket 20190007-EI. The compliance strategies for the MATS and CSAPR/CAIR Rules have been implemented. DEF anticipates impacts from the CWIS and CCR Rules, but all specific compliance measures or operational changes have not been identified. DEF has initiated studies and monitoring plans to develop the compliance strategies for these Rules. Please see the table below and tab 66 of the Excel file DEF 2019 SDR1 - Tables.xlsx.

Unit Impacts of EPA’s New and Proposed Rules

Unit	Unit Type	Fuel Type	Net Sum Capacity (MW)	Type of New and Proposed EPA Rule Impacts					Anticipated Impacts
				MATS	CSAPR/ CAIR	CWIS	CCR Non-Hazardous Waste	CCR Special Waste	
Anclote 1	Steam	NG	498	Convert to NG	Convert to NG, Dispatch	Impacted	N/A	N/A	Convert to NG
Anclote 2	Steam	NG	505						
Bartow PB4	CC	NG	1,104	N/A	Dispatch Changes	Impacted	N/A	N/A	N/A
Citrus Combined Cycle	CC	NG	1,632	N/A	N/A	Compliant as Constructed	N/A	N/A	N/A
Crystal River 1	Steam	Coal	370	Retired	Retired	Retired	N/A	N/A	Retired
Crystal River 2	Steam	Coal	499						
Crystal River 4	Steam	Coal	712	Reagents, CEMS	FGD & SCR, Dispatch	Impacted	Impacted	N/A	Reagents, CEMS
Crystal River 5	Steam	Coal	710						
Osprey	CC	NG	582	N/A	N/A	N/A	N/A	N/A	N/A
Hines PB1-4	CC	NG	2,045	N/A	Dispatch Changes	N/A	N/A	N/A	N/A
Notes									
(Include Notes Here)									

67. Please identify, for each unit impacted by one or more of the EPA's rules, what the estimated cost is for implementing each rule over the course of the planning period. As part of this response, please indicate the unit's name, type, fuel type, and net summer generating capacity. Please complete the table below and provide an electronic copy in Microsoft Excel format.

RESPONSE: The compliance strategies for the MATS and CAAPR/CAIR rules have been implemented. DEF anticipates costs for implementation of the CWIS and CCR Rules, but all specific compliance measures and associated costs have not been identified for all sites at this time. DEF has initiated studies and monitoring plans to develop the compliance strategies for these Rules. Please see the table below and tab 67 of the Excel file DEF 2019 SDR1 - Tables.xlsx.

Estimated Unit Cost of EPA's Rules

Unit	Unit Type	Fuel Type	Net Sum Capacity (MW)	Estimated Cost of EPA Rules Impacts (2019 $ millions)						
				MATS	CSAPR/ CAIR	CWIS	CCR Non-Hazardous Waste	CCR Special Waste	Anticipated Impacts	Total Cost
Anclote 1	Steam	NG	498	0	0	15 - 130	N/A	N/A	N/A	15 - 130
Anclote 2	Steam	NG	505							
Bartow PB4	CC	NG	1,104	0	0	10 - 170	N/A	N/A	N/A	10 - 170
Crystal River 4	Steam	Coal	712	0	0	10 - 20+	TBD	0	N/A	10 - 20+ CCR
Crystal River 5	Steam	Coal	710							
Notes										
(Include Notes Here)										

68. Please identify, for each unit impacted by one or more of EPA's rules, when and for what duration units would be required to be offline due to retirements, curtailments, installation of additional controls, or additional maintenance related to emission controls. Include important dates relating to each rule. Please complete the table below and provide an electronic copy in Microsoft Excel format.

<u>RESPONSE</u>: The compliance strategies for the MATS and CSAPR/CAIR rules have been implemented.

At this time, DEF cannot identify all potential impacts from the implementation of the CWIS and CCR Rules as the compliance strategies for those rules have not been completely developed. DEF has developed compliance strategies for CWIS compliance at Crystal River Units 4 and 5, but specific outage requirements have not been defined. DEF will attempt to schedule project implementation during planned outages to minimize unit downtime. Outage durations will be highly dependent on the compliance and technology choices.

Please see the table below and tab 68 of the Excel file DEF 2019 SDR1 - Tables.xlsx.

Estimated Timing of Unit Impacts of EPA's Rules

<table>
<tr><th rowspan="3">Unit</th><th rowspan="3">Unit Type</th><th rowspan="3">Fuel Type</th><th rowspan="3">Net Sum Capacity (MW)</th><th colspan="5">Estimated Timing of EPA Rule Impacts (Month/Year - Duration)</th></tr>
<tr><th rowspan="2">MATS</th><th rowspan="2">CSAPR/ CAIR</th><th rowspan="2">CWIS</th><th colspan="2">CCR</th></tr>
<tr><th>Non-Hazardous Waste</th><th>Special Waste</th></tr>
<tr><td>Anclote 1</td><td>Steam</td><td>NG</td><td>498</td><td rowspan="2">N/A</td><td rowspan="2">N/A</td><td rowspan="2">TBD</td><td rowspan="2">N/A</td><td rowspan="2">N/A</td></tr>
<tr><td>Anclote 2</td><td>Steam</td><td>NG</td><td>505</td></tr>
<tr><td>Bartow PB4</td><td>CC</td><td>NG</td><td>1,104</td><td>N/A</td><td>N/A</td><td>TBD</td><td>N/A</td><td>N/A</td></tr>
<tr><td>Citrus Combined Cycle</td><td>CC</td><td>NG</td><td>1,632</td><td>N/A</td><td>N/A</td><td>TBD</td><td>N/A</td><td>N/A</td></tr>
<tr><td>Crystal River 1</td><td>Steam</td><td>Coal</td><td>370</td><td rowspan="2">Retired</td><td rowspan="2">Retired</td><td rowspan="2">Retired</td><td rowspan="2">Retired</td><td rowspan="2">Retired</td></tr>
<tr><td>Crystal River 2</td><td>Steam</td><td>Coal</td><td>499</td></tr>
<tr><td>Crystal River 4</td><td>Steam</td><td>Coal</td><td>712</td><td rowspan="2">N/A</td><td rowspan="2">N/A</td><td rowspan="2">TBD</td><td rowspan="2">TBD</td><td rowspan="2">N/A</td></tr>
<tr><td>Crystal River 5</td><td>Steam</td><td>Coal</td><td>710</td></tr>
<tr><td>Osprey</td><td>CC</td><td>NG</td><td>582</td><td>N/A</td><td>N/A</td><td>N/A</td><td>N/A</td><td>N/A</td></tr>
<tr><td>Hines PB1-4</td><td>CC</td><td>NG</td><td>2,045</td><td>N/A</td><td>N/A</td><td>N/A</td><td>N/A</td><td>N/A</td></tr>
<tr><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td></td></tr>
<tr><td colspan="9">Notes</td></tr>
<tr><td colspan="9">Citrus CC will be 316(b) compliance when constructed; however, tie-in to the Crystal River Units 4 and 5 system may require a scheduled outage; timing is not yet determined.</td></tr>
</table>

69. Explain any expected reliability impacts resulting from each of the EPA rules listed below. As part of your explanation, please discuss the impacts of transmission constraints and units not modified by the rule, that may be required to maintain reliability if unit retirements, curtailments, additional emissions control upgrades, or longer outage times due to each of these EPA rules.
    a. Mercury and Air Toxics Standards (MATS) Rule.
    b. Cross-State Air Pollution Rule (CSAPR).

c. Cooling Water Intake Structures (CWIS) Rule.
d. Coal Combustion Residuals (CCR) Rule.
e. Standards of Performance for Greenhouse Gas Emissions for New Stationary Sources: Electric Utility Generating Units.

RESPONSE:

a. Reliability impacts are not anticipated with the compliance plan in effect.
b. No reliability impacts are anticipated.
c. Reliability impacts are not anticipated with the compliance plan in effect.
d. Reliability impacts are not anticipated with the compliance plan in effect.
e. Reliability impacts are not anticipated with application of these standards.

70. If applicable, identify any currently approved costs for environmental compliance investments made by your Company, including but not limited to renewable energy or energy efficiency measures, which would mitigate the need for future investments to comply with recently finalized or proposed EPA regulations. Briefly describe the nature of these investments and identify which rule(s) they are intended to address.

RESPONSE:

DEF's currently approved costs for environmental compliance investments which may be considered in the EPA's future CO2 regulations include plant conversions to natural gas, coal resource retirements, and utilizing advanced natural gas technologies as discussed in detail in question #69. These plans were undertaken to address the requirements of various new or forthcoming rules. The retirement of Crystal River units 1 and 2 in response to MATS and the Regional Haze rule will also reduce the impacts of the CCR rule, the CWIS rule and updates to the State Implementation Plan to achieve attainment with SO_2 and Ozone National Ambient Air Quality Standards (NAAQS). This retirement reduces DEF's CO2 footprint. The conversion of the two units at Anclote to natural gas firing in response to MATS will similarly reduce priority pollutant emissions and the resultant risk around future updates to the NAAQS as well as CO2 emissions.

Until the EPA's CO2 emission reduction regulation is clearly defined, DEF can only estimate which investments would contribute to compliance and to what degree. DEF does, however, have some approved renewable energy and energy efficiency investments, recovered or administered under the energy conservation cost recovery clause that may mitigate the need for some limited future investments that may be contemplated in the EPA's future CO2 regulations; and, finally, DEF continues to evaluate clean energy technologies and prudently prepare now for a CO2 constrained future.

71. What steps has your Company taken, is currently taking, or is planning to take to address curbing carbon dioxide emissions for existing sources? How has your Company addressed

the ruling by the U.S. Supreme Court that carbon dioxide is a pollutant under the Clean Air Act? How does your Company plan on addressing carbon dioxide emissions from existing sources during the 10-year site planning period?

RESPONSE: The Company has been considering carbon dioxide (CO2) emissions from its facilities in the resource planning process for many years and has considered the potential costs and impacts for carbon emission levels in numerous recent resource planning decisions. While there is a recognition that new regulations are often challenged by various entities for many reasons, the Company's recent planning efforts for CO2 emissions have focused on compliance with the EPA's Clean Air Act provisions for regulation of power plant emissions under the "Standards of Performance for Greenhouse Gas Emissions from New, Modified and Reconstructed Stationary Sources: Electric Utility Generating Units" and preparing for future CO2 and/or greenhouse gas regulation. The MATS compliance decisions to convert the Anclote units to 100% natural gas and the retirement of Crystal River 1 & 2 will result in CO2 emission reductions from existing facilities. The recent additions of the new combined cycle resources at the Osprey Plant and the Citrus County facility will support further CO2 fleet emission reductions through the use of high efficiency natural gas generation. DEF has also begun the construction of 700 MW of solar power generating facilities which will further reduce the company's CO2 emissions. The Company continues to consider the potential for further reductions as it evaluates options for future resources including solar energy facilities and potential new energy efficiency measures. As discussed in DEF's 2019 TYSP, DEF continues to use a carbon trading price as a proxy for the impacts of future carbon regulation in planning scenarios.

Fuel Supply & Transportation

72. Please provide, on a system-wide basis, the actual annual fuel usage (in GWh) and average fuel price (in nominal $/MMBTU) for each fuel type utilized by the Company in the period 2009–2018. Also, provide the forecasted annual fuel usage (in GWh) and forecasted annual average fuel price (in nominal $/MMBTU) for each fuel type forecasted to be used by the Company in the period 2019–2028. As part of this response, please complete the table below and provide the completed table in Microsoft Excel format.

RESPONSE: Please see the table below and tab 72 of the Excel file DEF 2019 SDR1 - Tables.xlsx.

Average Fuel Price Comparison

Year		Uranium		Coal		Natural Gas		Residual Oil		Distillate Oil	
		GWh	$/MMBTU	GWh	$/MMBTU	GWh	$/MMBTU	GWh	$/MMBTU	GWh	$/MMBTU
Actual	**2009**	4945	0.39	11089	4.19	18457	8.43	974	9.49	261	17.28
	2010	0	0	12115	4.05	23692	6.27	683	10.95	381	16.19
	2011	0	0	10809	3.83	23571	5.43	187	10.97	81	18.31
	2012	0	0	10003	3.83	23997	5.56	46	12.12	104	20.35
	2013	0	0	10577	3.94	23061	5.63	127	12.93	93	21.13
	2014	0	0	11729	3.98	22953	5.66	0	0	76	21.97
	2015	0	0	9718	3.72	25227	4.67	0	0	73	22.3
	2016	0	0	8885	3.62	24807	4.09	0	0	77	18.66
	2017	0	0	8722	3.44	27307	4.26	0	0	62	16.43
	2018	0	0	8422	3.20	28687	4.52	0	0	90	19.8
Projected	**2019**	0	0	5,373	2.44	32,820	2.98	0	0	5	16.38
	2020	0	0	3,495	2.45	34,735	2.79	0	0	19	16.45
	2021	0	0	3,074	2.51	35,251	2.73	0	0	12	16.77
	2022	0	0	2,752	2.57	34,575	2.73	0	0	9	16.94
	2023	0	0	3,123	2.59	33,920	2.78	0	0	7	16.36
	2024	0	0	3,675	2.76	34,847	3.08	0	0	34	15.87
	2025	0	0	3,697	2.87	34,657	3.54	0	0	74	15.54
	2026	0	0	3,916	2.98	34,585	4.06	0	0	38	15.67
	2027	0	0	3,824	3.09	35,223	4.46	0	0	67	16.01
	2028	0	0	3,930	3.13	35,377	4.78	0	0	63	16.43
Notes											
Actual Natural Gas Prices include fixed transportation costs. Projected Natural Gas Prices are projected on a variable cost basis.											

73. Please discuss how the Company compares its fuel price forecasts to recognized, authoritative independent forecasts.

<u>RESPONSE</u>:

DEF's fuel price forecasts are developed based on the forward market price for the first five years, followed by the long-term fundamental forecast beyond year five. The fundamental forecast is a long-term proprietary forecast prepared by a nationally recognized third-party consulting company.

As part of its forecast comparison process, Duke Energy compares its own fundamental commodity price outlooks to both public forecasts like EIA, and proprietary outlooks from leading energy consultants. Duke Energy also compares supply and demand fundamentals where they are available to review the underlying drivers. Coal price forecast comparisons are more tenuous given the limited number of qualified outlooks, the significance of transportation cost and the non- homogeneous nature of the commodity itself. Duke Energy utilizes direct comparisons for select coal product qualities widely available in the market. Since the objective of Duke Energy fundamental forecasting process is to produce a comprehensive internally consistent forecast, Duke Energy also performs checks that the final price forecast is intuitively aligned with the supply/demand balances across the various commodities.

74. Please identify and discuss expected industry trends and factors for each fuel type (coal, natural gas, nuclear fuel, oil, etc.) that may affect the Company during the period 2019–2028.
    a. Coal
    b. Natural Gas
    c. Nuclear (if applicable)
    d. Fuel Oil
    e. Other (please specify each, if any)

RESPONSES:

a. With respect to coal, high-sulfur Illinois basin coal prices generally are in the low $40's per ton; Central Appalachia coal prices are in the low to mid $60's per ton; Northern Appalachia coal prices are in the high $40's to low $50's per ton; Powder River Basin coal prices are in the mid $11's per ton; and Colorado coal prices are in the low $30's per ton. Coal demand is expected to fluctuate based on weather driven demand and changes in natural gas pricing and purchase power costs. Looking forward, coal markets are expected to be in a state of flux due to a number of factors, including: (a) uncertainty around proposed, imposed, and stayed U.S. Environmental Protection Agency ("EPA") regulations for power plants; (b) continued abundant natural gas supply and storage resulting in lower natural gas prices combined with installation of new combined cycle ("CC") generation by utilities, especially in the Southeast, which has lowered overall domestic coal demand; (c) continued changes in demand for global markets for both steam and metallurgical coal; (d) uncertainty surrounding regulations for mining operations; and (e) the on-going financial viability of many of the Company's coal suppliers.

b. Over the planning horizon there are a number of trends that could have an impact on natural gas prices and the overall supply and demand for domestic natural gas. First, is the level of production of domestic natural gas, particularly the continued growth in unconventional shale gas. Second, is the forecasted growth in the use of natural gas from electric power generation and industrial sector. Third, is the level of natural gas exports via pipelines to Mexico and LNG to the global natural gas market from U.S. export facilities.

   Currently, onshore shale gas production continues to grow in the lower-48 states, even in the current low-price environment. Per the U.S. Information Agency ("EIA") net dry domestic production has increased from January 2016 to April 2019 rising from approximately 70 Bcf/day to approximately 85 Bcf/day, with some variation. The EIA projects total U.S. natural gas supply to grow to approximately

105 Bcf/day in 2028. This growth will be primarily driven by horizontal drilling in shale formations which will continue to more than offset expected declines in traditional vertical drilling and offshore production. Although most of the projected production growth in comes from the Marcellus and Utica plays in the Appalachian region, associated natural gas from the Permian region in Texas and New Mexico is also projected to be a significant contributor. In 2028, the EIA forecasts domestic natural gas consumption will be approximately 87 Bcf/day, with exports at approximately 24 Bcf/day. Power generation is expected to be approximately 31 Bcf/day of the domestic natural gas demand in 2028.

Domestic natural gas demand growth is forecasted to be driven by electrical generation growth from coal-to-gas switching and industrial growth predominantly from new facilities in the Gulf Coast. As conversions and retirements of older and less efficient coal plants are replaced with natural gas, natural gas' market share of electrical generation is forecasted to continue to increase. The EIA Annual Energy Outlook 2019 ("AEO 2019") reference case projects natural gas to remain the leading source of electricity generation in the United States through 2050, accounting for 38.5% of electricity generation, an increase from 31% in 2017. The EIA states that projected natural gas growth in electric power generation is supported by increased competitiveness with renewables after the expiration of renewable tax credits in the mid-2020s and the relatively low forecast natural gas prices throughout the projection.

Prior to the increase of shale gas production over the past several years, LNG imports were viewed as a key supply resource to fill the incremental supply needs of U.S. demand growth. However, given the success in unconventional shale natural gas supply growth, previously forecasted net LNG imports are now forecasted to be net LNG exports. The first U.S. LNG export from a lower-48 state shipped from a facility in Louisiana in February 2016. By April 2017 it was reported by Platts that the Gulf Coast had shipped its one hundredth LNG export cargo. According to the EIA, U.S. exports of LNG reached 3 Bcf/d in 2018, up from 0.5 Bcf/d in 2016, and 1.94 Bcf/d in 2017. Dominion Energy's Cove Point LNG export facility in Cove Point, Maryland was the second operational export facility in the lower 48 states and its first export cargo left in March 2018.

Demand growth for natural gas from electric generation, industrial, and exports could result in additional upward pressure on prices over the planning horizon from 2019 through 2028. The AEO 2019 Reference Case forecasts that the Henry Hub gas price (in 2018 dollars) could increase to $3.71/MMBtu in 2028, with prices forecasted at $4.87/MMBtu in 2050.

c. DEF has retired the Crystal River 3 Nuclear plant and does not expect to be significantly impacted by trends and factors of nuclear fuel.

d. With respect to industry trends, high levels of crude oil inventories and lower-cost drilling technology advancements have continued to increase production levels and place downward pressure on the oil market. In 2018, U.S. crude oil production surpassed the record of 9.6 million barrels per day (b/d) set in 1970 and will continue to grow as upstream producers increase output because of the combined effects of rising prices and production cost reductions. The growth occurs mainly in the Permian Basin in the Southwest Texas region. Per the EIA's AEO 2019 Reference Case, spot WTI (U.S. Midcontinent area) crude is expected to be approximately $67.88 a barrel in 2019, rising to approximately $69.72 in 2020. After 2020, the EIA expects growth in demand from non-Organization for Economic Co-operation and Development ("OECD") countries to result in a return to higher world oil prices with WTI area crude reaching approximately $84.05 a barrel in 2028 and approximately $104.52 a barrel in 2050. Price estimates are in real 2018 dollars.

   DEF will continue to monitor oil prices; trends and its fuel forecast over time and will procure needed fuel oil supply and transportation services to meet its generation fleet needs over the planning horizon. As new information becomes available, DEF will monitor this information for potential developments.

e. DEF is developing an increasing portfolio of solar PV generation projects. While these do not have a fuel source per se, DEF evaluates the price of solar generating equipment and the energy value that it delivers in relation to the overall dispatch value of conventional generation, which is primarily driven by fuel price. DEF engages a nationally recognized consultant to provide a ten-year forecast of expected solar installation prices. This forecast indicates a slowing of the precipitous downward price change that solar PV has experienced in the last 5-10 years, but still a continuing trend in the range 3-5% annual decreases. These will be offset on a case by case basis by increases in transmission, land and other non-equipment costs. Nevertheless, DEF expects increasing cost effectiveness for PV solar in the ten-year period.

75. Please identify and discuss steps that the Company has taken to ensure natural gas supply availability and transportation over the 2019–2028 planning period.

RESPONSE: DEF has broad contacts and relationships with natural gas suppliers and pipeline transportation providers. DEF performs shorter term and long-term fuel forecasts to project estimated fuel usage for future periods. The short-term forecasts typically cover a period of five years, and the long-term forecasts cover years six through year twenty. Fuel forecasts includes items such as, but not limited to, load forecasts, fuel and emission prices, operational specifics of owned generation and contracted generation resources, wholesale power sales agreements, and unit maintenance schedules. The short-term forecast is performed approximately four times per year for a five-year period and currently covers years 2019 through 2024. The long-term forecast is performed two times per year and currently covers years 2025 through 2038.

To ensure that DEF has the needed natural gas supply to meets its generation needs over the planning horizon, DEF performs periodic competitive natural gas supply Request for Proposals ("RFP's") and market solicitations to procure the needed competitive natural gas supply consistent with its procurement approach. In addition, DEF also monitors potential pipeline expansion projects that can access competitively priced and secure natural gas for delivery to DEF's facilities. DEF monitors potential pipeline expansions through on-going discussions and periodic meetings with gas suppliers and pipeline providers, open seasons issued by pipelines, industry events, and publications.

76. Please identify and discuss any existing or planned natural gas pipeline expansion project(s), including new pipelines and those occurring or planned to occur outside of Florida that would affect the Company for the period 2019–2028.

RESPONSE: The project descriptions outlined below are not intended to be an all-inclusive or exhaustive list of all the upstream pipeline projects that are in-service or proposed in the Gulf Coast and Southeast region, but those that DEF believes could have an impact on the natural gas supply available for DEF and the State of Florida.

Columbia Gulf Transmission – Gulf Xpress

Status: In-service as of March 15, 2019

Columbia Gulf recently completed a reversal project that involved the construction of seven new midpoint compressor stations in Kentucky, Tennessee and Mississippi to allow an additional 875,000 MMBtu/day of Marcellus and Utica gas to reach the Gulf Coast. DEF currently receives gas into SESH from Columbia Gulf.

Destin Pipeline

Status: In-Service

The Destin pipeline is a 255-mile natural gas transport system with total capacity of 1.2 Bcf/d. The offshore portion of the system is 120 miles of pipe in the Gulf of Mexico. The onshore portion of Destin extends 135 miles north in Mississippi. Destin currently serves as a primary transport of gas flows from the Anadarko, Barnett and Haynesville shale plays to Florida markets through interconnections with major interstate pipelines. Destin is jointly owned by American Midstream and Enbridge. American Midstream is the current operator.

Gulf Crossing Pipeline

Status: In-Service

Gulf Crossing, a Boardwalk Pipeline Company, is an approximately 1.7 Bcf/day capacity pipeline that was put into service in March 2009. This expansion project consisted of approximately 357 miles of 42-inch pipe that accesses onshore natural gas supply from the Barnett and Woodford Shale located in North Central Texas and Southeast Oklahoma. This project provided incremental gas to serve the Southeast U.S. markets by interconnecting with Transco in Choctaw County, Alabama. Additionally, it delivers gas into SESH at the Perryville Hub located near Delhi, Louisiana and into Destin located in Clarke County, Mississippi. This project provides additional access to onshore supply that can be delivered into DEF’s existing capacity on Transco’s Mobile Bay South Lateral, SESH and Destin.

Gulf South Pipeline - Southeast Market Expansion

Status: In-Service

Gulf South, a Boardwalk Pipeline Company, held a binding open season for expansion of its existing pipeline capacity from the Carthage, Texas area or from the Perryville, Louisiana area with deliveries into the Mobile, Alabama area in June 2012. The expansion was initially planned for a 400,000 MMBtu/day capacity addition. The actual expansion was for 510,500 MMBtu/day and was placed in service in November 2014. This expansion project provided additional access to onshore supply for Gulf South customers that can be delivered into delivery points that are connected to Florida Gas Transmission.

Mid-Continent Express Pipeline (“MEP”)

Status: In-Service

MEP is 50% owned by each Energy Transfer Partners and Kinder Morgan. Their expansion project was approximately 1.5 Bcf/day capacity pipeline in Zone 1 (Oklahoma to Delhi, Louisiana) and 1.0 Bcf/day Capacity in Zone 2 (Delhi, Louisiana to Butler, Alabama) which was placed in-service in August 2009. MEP was expanded by compression additions to approximately 1.8 Bcf/day in Zone 1 and 1.2 Bcf/day in Zone 2 in the summer of 2010. This project accesses growing unconventional onshore natural gas supply from the Barnett, Woodford, and Haynesville shale formations. This helps provide secure and competitively priced onshore unconventional natural gas to serve the Southeast U.S., including Florida, by interconnecting with Transco in Choctaw County, Alabama. This expansion provides additional access to unconventional onshore supply that can be delivered to DEF’s firm transportation capacity on the Transco Mobile Bay Lateral and Sabal Trail Transmission.

Sabal Trail Transmission

Status: In-Service

Sabal Trail Transmission, LLC is a joint venture of Spectra Energy Corp (an Enbridge subsidiary), NextEra Energy, and Duke Energy. Sabal Trail is an approximately 515-mile interstate pipeline extending from Transco Station 85 in Choctaw County, Alabama to the Central Florida Hub. It interconnects with FGT, Gulfstream, and the Florida Southeast Connection in Osceola County, Florida. Sabal Trail's Phase I facilities were placed into full commercial service on July 3, 2017. The full Phase I capacity of the Sabal Trail pipeline is 830,000 Dth/day with the ability to scale-up its design capacity of 1.1 Bcf/day beyond 2020. Adding this additional pipeline into the State will increase overall direct onshore supply access to the State of Florida. Sabal Trail has two foundation shippers, Florida Power & Light and DEF.

Southeast Supply Header (“SESH”)

Status: In-Service

SESH is a 50/50 joint venture between Spectra Energy Partners (an Enbridge subsidiary) and Enable Midstream. SESH was a new greenfield natural gas pipeline system consisting of approximately 269 miles of pipe, three mainline compressor stations, two booster stations and other facilities. SESH extends from near Perryville, Louisiana and terminates at an interconnection with Gulfstream near Coden, Alabama. SESH currently has approximately
1.09 Bcf/day of transportation capacity.

SESH interconnects with Gulf South Pipeline, Center Point Transmission, and ETC's Tiger Pipeline to provide access to onshore unconventional natural gas supply from the Barnett Shale, Bossier Sands, Arkoma, Haynesville and Fayetteville shale basins. Also, SESH has interconnections with Columbia Gulf, TETCO, and TGP which provide it the ability to receive Marcellus and Utica gas from Northeast regions of the U.S. SESH allows DEF to access competitively priced onshore natural gas supply that can be delivered from SESH into Florida Gas Transmission and Gulfstream. SESH went into service in September 2008.

Tennessee Gas Pipeline ("TGP") – Broad Run Flexibility & Expansion Projects
<u>Flexibility Status: In-Service November 2015 Expansion Status: In-Service October 2018</u>
TGP is owned and operated by Kinder Morgan Energy Partners. Kinder Morgan held an open season in 2014 for its Broad Run project and awarded all 790 Mdth/day to Antero Resources. The overall project is broken into two pieces: flexibility and expansion. The flexibility project provides 590 Mdth/day, while the expansion project will provide 200 Mdth/day. TGP pipeline traditionally flowed from the Gulf Coast to the Northeast. With the growth of Marcellus and Utica shale production, the flow of gas has reversed flow on TGP from Ohio and Pennsylvania to the Gulf Coast. The Broad Run projects are one way to accomplish this "backhaul." These projects allow gas to flow southward on TGP to interconnects with other interstate pipelines such as FGT, Gulf South, MEP, SESH, and Transco. This gas provides additional opportunities for DEF to diversify their supply. The Broad Run project was fully in-service late October 2018.

Texas Gas – Northern Supply Access
<u>Status: In-service expected Mid-2020</u>
A "backhaul" reversal project that will allow 384,000 MMBtu/day of gas from the Ohio Utica flow to Louisiana through the reversal of compressor stations. Texas Gas supplies the Perryville Area in Eastern Louisiana, which is the same geographic area where SESH originates.

Texas Eastern Transmission Company ("TETCO") – Multiple "Backhaul" Projects
<u>Status: In-service</u>
TETCO, owned and operated by Spectra Energy (an Enbridge subsidiary), is a 10.46 Bcf/day pipeline that has traditionally flowed from the Gulf Coast to the Northeast. With the growth of Marcellus and Utica shale production, the flow of gas has reversed flow from Ohio and Pennsylvania to the Gulf Coast. To accomplish this "backhaul," multiple projects have been both completed and announced on the 30-inch portion of the TETCO system. The Team 2014 (250 Mdth/day), Team South (300 Mdth/day), and Open (550

Mdth/day) projects were all completed between November 2014 and November 2015. Two additional projects, Gulf Markets (650 Mdth/day) and Access South (320 Mdth/day), were placed in- service in 2017. These projects allow gas to flow southward on TETCO to interconnects with FGT, Gulf South, MEP, SESH, and Transco. This gas provides additional opportunities for DEF to diversify their supply.

Transcontinental Gas Pipe Line Company ("Transco") - Mobile Bay South Phase I, II and III Expansions

Status: In-Service

Transco, owned and operated by Williams, put Mobile Bay Phase I Expansion into service in May 2010. The project provides incremental capacity from Transco's Station 85 pool and other points in Choctaw County, Alabama to points on its Mobile Bay Lateral as far south as the existing interconnect between Transco and Gulfstream in Mobile County, Alabama. The expansion will also provide deliveries into FGT and Gulfstream. This project allows DEF to access a liquid supply point with competitively priced onshore unconventional natural gas supply.

Transco put Mobile Bay Phase II Expansion into service in May 2011. The expansion provides deliveries into FGT and Gulfstream via the Mobile Bay Lateral. The project provides incremental capacity from Transco's Station 85 pool and other points in Choctaw County, Alabama to points on its Mobile Bay Lateral as far south as the existing interconnect between Transco and Gulfstream in Mobile County, Alabama. The expansion will also provide deliveries into FGT and Gulfstream. This project allows DEF to access a liquid supply point with competitively priced onshore unconventional natural gas supply.

In July 2012, Transco announced that it was holding a non-binding open season for up-to 325,000 MMBtu/day firm transportation service available from Transco's Mobile Bay South Lateral in Choctaw County, Alabama to the point of interconnection between Transco and Bay Gas Storage in Mobile County, Alabama under Transco's proposed "Mobile Bay South III Expansion." The expansion has a capacity of 225,000 MMBtu/day, which provides deliveries into FGT and Bay Gas Storage via the Mobile Bay Lateral. The project Certificate Application was filed with FERC in July 2013 and the project was placed in-service in April 2015.

Transco - Leidy Southeast Project

Status: In-Service

The Leidy Southeast Project provides an incremental 525,000 MMBtu/day of capacity from Transco's Leidy Line Receipts in Northeast Pennsylvania to points of delivery as far south as Transco's mainline Station 85 Zone 4 Pooling Point. The Leidy Southeast Project moves growing Marcellus shale gas production north-to-south to various markets on the Transco mainline. Leidy Southeast went into service in late 2015. DEF is not a shipper in this project but may benefit from incremental Marcellus Shale gas supply that could be available at Transco Station 85 where DEF could access this supply to transport on Sabal Trail and/or Transco's Mobile Bay South Lateral.

Transco - Hillabee Expansion Project

Status: In-Service

The Transco Hillabee Expansion Project will provide 1,131,730 MMBtu/day of incremental firm capacity in three phases. It originates at Transco Station 85 in Choctaw County, Alabama to a proposed interconnection between Transco and Sabal Trail in Tallapoosa County, Alabama. Sabal Trail acquired 100% of the project capacity via a long-term lease to provide Sabal Trail shippers gas supply access at Transco Station 85. Construction for Phase 1 began in 2016 and was placed in-service in July 2017. Phase II and III are targeted to go in-service in 2020 and 2021, respectively.

Transco - Atlantic Sunrise Project

Status: In-Service

The Atlantic Sunrise Project provides an incremental 1,700,000 MMBtu/day of capacity from Transco's Leidy Line Receipts in Northeast Pennsylvania to points south and east. 850,000 MMBtu/day of this volume could deliver as far South as Transco's mainline Station 85 Zone 4 Pooling Point. The Atlantic Sunrise Project moves growing Marcellus shale gas production North-to-South to various markets on the Transco mainline. DEF is not a shipper in this project but may benefit from incremental Marcellus shale gas supply that could be available at Transco Station 85 where DEF could access this supply to transport into Florida on downstream capacity on Sabal Trail and/or Transco's Mobile Bay South Lateral. The mainline portion of the pipeline went into service in September 2017, while the reminder of the project went into full service in October 2018.

Transco – Southeastern Trails Project

Status: Projected In-service targeted for November 2020

The Southeastern Trail Expansion (SET) is a 296,375 MMBtu/day expansion of the Transco pipeline system designed to provide additional pipeline capacity to serve markets in the Mid-Atlantic and Southeastern states by November 2020. It is an expansion from the existing Zone 5 Pleasant Valley Interconnect between Transco and Dominion Cove Point in Virginia to Transco's existing Zone 3 Pooling Point at Station 65 in Louisiana. The project has been designed to provide additional reliable service to utility and local distribution companies located in Virginia, North Carolina, South Carolina and Georgia. The Southeastern Trails Project moves gas from north-to-south to various markets on the Transco mainline. DEF is not a shipper in this project but may benefit from incremental gas supply that could be available at Transco Station 85 where DEF could access this supply to transport into Florida on downstream capacity on Sabal Trail and/or Transco's Mobile Bay South Lateral.

77. Please identify and discuss expected liquefied natural gas (LNG) industry factors and trends that will impact the Company, including the potential impact on the price and availability of natural gas, for the period 2019–2028.

RESPONSE: Projections of expected LNG exports vary and will be influenced by global pricing and production. Per the FERC, by 2020 the U.S. is expected to have over 10 Bcf/day of export capability. Per the FERC, as of early 2019, there is approximately 5

Bcf/day of export capacity in-service, with another 6.7 Bcf/day of LNG export capability that is permitted and under construction at five facilities in Louisiana, Texas and Georgia. These facilities will come online in different stages between 2019 and 2021. There is also 8.2 Bcf/day of capacity at five facilities in Louisiana and Texas that has been approved, but construction has not yet started. Cheniere Energy's LNG export facility in Sabine Pass, Louisiana was the first operational LNG export facility in the lower 48 states and its first export cargo left in February 2016 bound for South America. Dominion Energy’s Cove Point LNG export facility in Cove Point, Maryland was the second operational export facility in the lower 48 states and its first export cargo left in March 2018.

Per the FERC, as of early 2019 there are another thirteen pending FERC applications for LNG export facilities in the Gulf Coast with expected capacity of approximately 22.2 Bcf/day. As of early 2019 there are also five projects in pre-filing with the FERC, with a total proposed capacity of approximately 4 Bcf/day. All five of these projects are in the Gulf Coast, with four in Louisiana and one in Texas. It is unlikely that all of the proposed pending or pre-filed projects in the Gulf Coast (approximately 26 Bcf/day total volumes) will be approved and constructed.

In the EIA’s 2019 Annual Energy Outlook reference case, the U.S. transitioned from being a natural gas net importer (pipeline and LNG gas) of approximately 2 Bcf/day in 2016 to a net exporter (pipeline and LNG gas) in 2018 with approximately 2 Bcf/day of net exports. The outlook shows net exports continuing to grow after 2018, with estimates of net exports of 9 Bcf/day in 2020. 7 Bcf/day of this being LNG exports, with the balance being net pipeline exports primarily to Mexico. The growth in U.S. LNG exports are supported by differences between domestic and international natural gas prices. However, the difference between domestic and international natural gas prices is assumed to tighten later in the projection period as a result of growth in U.S. LNG export capacity. U.S. natural gas prices are currently determined primarily by the availability and cost of domestic natural gas resources.

The future trends of U.S. LNG exports are difficult to predict as it can be impacted by both domestic and global developments over the long-term period. These factors include, but are not limited to, global natural gas prices, fundamentals of supply and demand, storage levels, economic cycles, and government regulations. As the global LNG supply grows, U.S. gas supply will compete with other global LNG exporters. DEF will continue to monitor LNG infrastructure projects and exports from these facilities.

78. Please identify and discuss the Company’s plans for the use of firm natural gas storage for the period 2019–2028.

RESPONSE: DEF utilizes firm natural gas storage as part of its overall gas fuel contract portfolio. DEF has agreements with Bay Gas Storage Company LTD (“Bay Gas”) and SG Resources Mississippi LLC (“Southern Pines”) for firm storage capacity. Both gas storage facilities are directly connected to interstate pipelines (FGT, Gulfstream, SESH and Transco) on which DEF currently holds firm transportation. Bay Gas and Southern Pines both provide DEF with greater supply reliability, operational flexibility, and price protection during severe weather events and pipeline operational flow orders. DEF expects high deliverability storage to continue to be a critical key component of its overall natural gas contract portfolio throughout the planning period. DEF will continue to evaluate any additional needs for firm gas storage capacity throughout the planning period.

79. Please identify and discuss expected coal transportation industry trends and factors, for transportation by both rail and water that will impact the Company during the period 2019–2028. Please include a discussion of actions taken by the Company to promote competition among coal transportation modes, as well as expected changes to terminals and port facilities that could affect coal transportation.

RESPONSE: With respect to transportation by rail, increased mining costs, declining productivity, declining coal reserves, lower quality coal from basins that DEF has purchased coal historically and low natural gas pricing continues to apply pressure for coal transported by rail to be cost competitive. Additionally, any increased demand for coal in foreign countries could put pressure on the railroads infrastructure to transport coal to the ports for export shipments. DEF expects the coal market will remain volatile and that varying modes of transportation will provide valuable flexibility.

With respect to water transportation, because of the addition of scrubbers to many coal generation plants in the Midwest and Southeast, use of higher sulfur coal originating from the Illinois Basin has increased with the main mode of transportation from this region being via water. DEF has monitored this trend and continues to explore opportunities to increase waterborne coal delivery. DEF expects the coal market will remain volatile and that varying modes of transportation will provide valuable flexibility. Terminal services in the Gulf will be critical to enable DEF to continue purchasing waterborne coals.

DEF has a long-term contract with a Gulf terminal for storage capacity along with a contract to load coal directly from a river barge to an ocean barge which allows DEF to mitigate unfavorable weather and operational impacts while ensuring reliable loading operations. DEF continuously communicates with barge companies, terminal facilities and Gulf barge companies to share its strategies for coal transportation via water. DEF continuously seeks opportunities to diversify its water transportation and terminal portfolio to ensure a reliable fuel supply.

Having the ability to transport coal via waterborne barge and rail transportation creates opportunities for competition between transportation modes. Additionally, the ability to take coal from various coal basins promotes competition between the different modes of transportation as well as the competition of coal pricing between coal basins. DEF expects that rail companies will look for opportunities to expand its infrastructure in the Illinois Basin to meet the increased demand from this basin. DEF continues to monitor and explore opportunities to maintain competition between water and rail delivery of coal.

80. Please identify and discuss any expected changes in coal handling, blending, unloading, and storage for any planned changes and construction projects at coal generating units for the period 2019–2028.

RESPONSE: Coal handling, blending, unloading, and storage requirements for coals from different basins are a consideration when determining coals to purchase. Continuous communications with the station, terminal facilities, river and gulf barge companies, and railroads are critical for DEF's coal transportation strategy in the future.

81. **[DEF & FPL Only]** Please identify and discuss the Company's plans for the storage and disposal of spent nuclear fuel for the period 2019–2028. As part of this discussion, please include the Company's expectation regarding short-term and long-term storage, dry cask storage, litigation involving spent nuclear fuel, and any relevant legislation.

RESPONSE: The United States Federal Government is legally obligated to take title and possession of all spent nuclear fuel. DEF will utilize on-site dry storage until the government fulfills its contractual obligations. All fuel at Crystal River #3 has been moved into dry cask storage. Reimbursement for costs incurred to store fuel on site is expected if the storage is as a result of the DOE's breach of the standard contract for disposal of spent nuclear fuel. DEF cannot predict what future actions the government will take to fulfill its contractual obligations. The Nuclear Waste Policy Act of 1982, as amended cannot be changed except by an act of Congress.