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SOAH DOCKET NO. 473-22-04394
PUC DOCKET NO. 53719

APPLICATION OF ENTERGY TEXAS, INC. FOR AUTHORITY TO CHANGE RATES	§ § §	**BEFORE THE STATE OFFICE OF ADMINISTRATIVE HEARINGS**

TEXAS INDUSTRIAL ENERGY CONSUMERS' RESPONSE TO ENTERGY TEXAS, INC.'S THIRD REQUEST FOR INFORMATION

Texas Industrial Energy Consumers ("TIEC") files the following responses to the First Request for Information ("RFI") to TIEC filed by Entergy Texas, Inc. ("ETI"). The request was filed at the Commission and received by TIEC on November 3, 2022. TIEC's responses to specific questions are set for as follows, in the order of the questions asked. Pursuant to 16 T.A.C. § 22.144(c)(2)(F), these responses may be treated as if they were filed under oath.

Respectfully submitted,

O'MELVENY & MYERS LLP

/s/ Christian E. Rice

Rex D. VanMiddlesworth
State Bar No. 20449400
Benjamin B. Hallmark
State Bar No. 24069865
Christian E. Rice
State Bar No. 24122294
303 Colorado St., Suite 2750
Austin, TX 78701
(737) 204-4720
rexvanm@omm.com
bhallmark@omm.com
crice@omm.com
OMMeservice@omm.com

ATTORNEYS FOR TEXAS INDUSTRIAL ENERGY CONSUMERS

CERTIFICATE OF SERVICE

I, Christian E. Rice, Attorney for TIEC, hereby certify that a copy of this document was served on all parties of record in this proceeding on this 10th day of November 2022 by electronic mail, facsimile, and/or First Class, U.S. Mail, Postage Prepaid.

/s/ Christian E. Rice
Christian E. Rice

SOAH DOCKET NO. 473-22-04394
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TEXAS INDUSTRIAL ENERGY CONSUMERS' RESPONSE TO ENTERGY TEXAS, INC.'S THIRD REQUEST FOR INFORMATION

ETI-TIEC 3-1

Please provide copies of all documents that Mr. Pollock reviewed and/or relied on to compile Exhibits JP-1 and JP-3.

Response:

Please see Attachment ETI-TIEC 3-1 Exhibit JP-1 and Attachment ETI-TIEC 3-1 Exhibit JP-3. Please also see the workpapers to the direct testimony of Jeffry Pollock.

Preparer: Jeffry Pollock
Sponsor: Jeffry Pollock

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TEXAS INDUSTRIAL ENERGY CONSUMERS' RESPONSE TO ENTERGY TEXAS, INC.'S THIRD REQUEST FOR INFORMATION

ETI-TIEC 3-2

In his prior testimony, has Mr. Pollock recommended a useful life for utility assets based on the manufacturer's warranty? If so, provide copies of the testimony or identify the testimony with specificity, including the regulatory commission it was filed before, the docket number, the caption, and the date filed.

Response:

Pursuant to an agreement with counsel for ETI, ETI-TIEC 3-2 has been amended as follows:

In his *testimony over the past ten years*, has Mr. Pollock recommended a useful life for utility assets based on the manufacturer's warranty? If so, provide copies of the testimony or identify the testimony with specificity, including the regulatory commission it was filed before, the docket number, the caption, and the date filed.

Yes. Mr. Pollock has previously offered testimony recommending that the useful life for assets should be based on a manufacturer's warranty. These testimonies are identified below.

> *Application of MidAmerican Energy Company for Determination of Ratemaking Principles*, Docket No. RPU-2016-0001, Direct Testimony of Jeffry Pollock, filed before the Iowa Utilities Board on June 21, 2016.
>
> *Application of Entergy Texas Inc. to Amend its Certificate of Convenience and Necessity for the Acquisition of a Solar Facility in Liberty County*, Docket No. 51215, Direct Testimony and Exhibits of Jeffry Pollock, filed before the Public Utility Commission of Texas on March 5, 2021.
>
> *In the Matter of the Application Of Entergy Arkansas, LLC for Approval of a Build-Own-Transfer Arrangement for a Renewable Resource in Crittenden County and for All Other Related Approvals*, Docket No. 20-067-U, Direct Testimony and Exhibits of Jeffry Pollock, filed before the Arkansas Public Service Commission on May 6, 2021.

Preparer: Jeffry Pollock
Sponsor: Jeffry Pollock

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TEXAS INDUSTRIAL ENERGY CONSUMERS' RESPONSE TO ENTERGY TEXAS, INC.'S THIRD REQUEST FOR INFORMATION

ETI-TIEC 3-3

Does Mr. Pollock agree that Exhibit JP-1 is limited to Combined Cycle Gas Turbine (CCGT) Power Plants with lifespans of 40 years or longer?

Response:

Yes.

Preparer: Jeffry Pollock
Sponsor: Jeffry Pollock

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ETI-TIEC 3-4

Did the sources Mr. Pollock reviewed in preparing Exhibit JP-1 include any CCGTs with expected lifespans of less than 40 years? If so, identify the plant, utility, nameplate capacity, in-service year, retirement year, and lifespan for such CCGTs.

Response:

No.

Preparer: Jeffry Pollock
Sponsor: Jeffry Pollock

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TEXAS INDUSTRIAL ENERGY CONSUMERS' RESPONSE TO ENTERGY TEXAS, INC.'S THIRD REQUEST FOR INFORMATION

ETI-TIEC 3-5

Does Mr. Pollock agree that there is a range of lifespans for CCGTs? To the extent Mr. Pollock agrees, what is a reasonable range? To the extent Mr. Pollock disagrees in whole or in part, provide all support for his position.

Response:

Yes. As evidenced in Exhibit JP-1 and Exhibit JP-3, CCGTs have a range of lifespans. However, Mr. Pollock does not opine on what constitutes a reasonable range for the lifespan of these facilities.

Preparer: Jeffry Pollock
Sponsor: Jeffry Pollock

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ETI-TIEC 3-6

Does Mr. Pollock agree that the lifespan for a CCGT should be assigned based on the facts and circumstances for that particular CCGT? To the extent Mr. Pollock disagrees in whole or in part, provide all support for his position.

Response:

This request is unclear as to what particular facts and circumstances may affect a given CCGT's assumed lifespan. The burden of proof lies with the utility to demonstrate to the Commission and intervenors how these factors may result in a given generating facility having an altered lifespan.

Preparer: Jeffry Pollock
Sponsor: Jeffry Pollock

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TEXAS INDUSTRIAL ENERGY CONSUMERS' RESPONSE TO ENTERGY TEXAS, INC.'S THIRD REQUEST FOR INFORMATION

ETI-TIEC 3-7

Does Mr. Pollock agree that settled cases before the Commission have no precedential value? To the extent Mr. Pollock disagrees in whole or in part, provide all support for his position.

Response:

Mr. Pollock partially agrees. For example, depreciation studies are relied upon by the Commission to establish depreciation rates which determine the rates paid by customers. To the extent that the Commission has approved these depreciation rates in a settled case, the depreciation study and resultant depreciation rates would necessarily have precedential value in terms of being applied until changed.

Preparer: Jeffry Pollock
Sponsor: Jeffry Pollock

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TEXAS INDUSTRIAL ENERGY CONSUMERS' RESPONSE TO ENTERGY TEXAS, INC.'S THIRD REQUEST FOR INFORMATION

ETI-TIEC 3-8

In his prior testimony, has Mr. Pollock ever raised environmental cost concerns in connection with constructing or operating coal plants or units? If so, provide copies of the testimony or identify the testimony with specificity, including the regulatory commission it was filed before, the docket number, the caption, and the date filed.

Response:

Pursuant to an agreement with counsel for ETI, ETI-TIEC 3-8 has been amended as follows:

In his *testimony over the past ten years*, has Mr. Pollock ever raised environmental cost concerns in connection with constructing or operating coal plants or units? If so, provide copies of the testimony or identify the testimony with specificity, including the regulatory commission it was filed before, the docket number, the caption, and the date filed.

Yes. Mr. Pollock has previously offered testimony addressing environmental cost concerns in connection with the operation of coal units. Pursuant to an agreement with ETI's counsel, testimonies addressing this issue filed within the last ten years are identified below.

Application of Southwestern Electric Power Company for Authority to Change Rates and Reconcile Fuel Costs, Docket No. 40443, Direct Testimony and Exhibits of Jeffry Pollock, filed before the Public Utility Commission of Texas on December 10, 2012.

In re: Petition for approval of arrangement to mitigate impact of unfavorable Cedar Bay power purchase obligation, by Florida Power & Light Company, Docket No. 150075-EI, Direct Testimony and Exhibits of Jeffry Pollock, filed before the Florida Public Service Commission on June 8, 2015.

In the Matter of the Application of Southwestern Public Service Company for Revision of its Retail Electric Rates Pursuant to Advice Notice 272, Case No. 17-00255-UT, Direct Testimony and Exhibits of Jeffry Pollock, filed before the New Mexico Public Regulation Commission on April 13, 2018.

Application of Southwestern Public Service Company for Authority to Change Rates, Docket No. 47527, Direct Testimony and Exhibits of Jeffry Pollock, filed before the Public Utility Commission of Texas on April 25, 2018.

In the Matter of: Application of Duke Energy Progress, LLC for Adjustments in Electric Rate Schedules and Tariffs and Request for an Accounting Order, Docket No. 2018-318-E, Direct Testimony of Jeffry Pollock, filed before the Public Service Commission of South Carolina on March 4, 2019.

In Re: Georgia Power Company's 2019 Rate Case, Docket No. 42516, Direct Testimony and Exhibits of Jeffry Pollock, filed before the Georgia Public Service Commission on October 17, 2019.

In the Matter of the Commission's Investigation Pursuant to Wyo. Stat. § 37-2-117 to Assure Full Understanding of the Origins, Methodology and Results of the Coal Study Undertaken by PacifiCorp, d/b/a in Wyoming as Rocky Mountain Power, Docket No. 90000-144-XI-19 (Record No. 15280), Direct Testimony and Exhibits of Jeffry Pollock, filed before the Wyoming Public Service Commission on April 1, 2020.

In Re: MidAmerican Energy Company Electric Power Generation Facility Emissions Plan, Docket No. EPB-2020-0156, Reply Testimony of Jeffry Pollock, filed before the Iowa Utilities Board on January 21, 2021.

Preparer: Jeffry Pollock
Sponsor: Jeffry Pollock

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ETI-TIEC 3-9

Is it Mr. Pollock's opinion that ETI should continue to operate Nelson 6 and Big Cajun 2 Unit 3 through 2042 and 2043, respectively, regardless of the environmental compliance costs for sulfur dioxide ("SO2") and nitrogen oxides ("NOx") emission reduction technologies (hereinafter "environmental compliance costs")?

Response:

Mr. Pollock does not opine on whether it is acceptable to continue operation of Nelson 6 and Big Cajun 2 Unit 3 through the end of their useful lives regardless of environmental compliance costs. The analysis presented in his testimony notes only that there are flaws with the decision to deactivate these units based upon the results of the deactivation analyses.

Preparer: Jeffry Pollock
Sponsor: Jeffry Pollock

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ETI-TIEC 3-10

Is it Mr. Pollock's position that ETI can continue to operate Nelson 6 and Big Cajun 2 Unit 3 and avoid the environmental compliance costs? If so, provide all support for his position.

Response:

No.

Preparer: Jeffry Pollock
Sponsor: Jeffry Pollock

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TEXAS INDUSTRIAL ENERGY CONSUMERS' RESPONSE TO ENTERGY TEXAS, INC.'S THIRD REQUEST FOR INFORMATION

ETI-TIEC 3-11

Is it Mr. Pollock's opinion that ETI should deactivate or retire Nelson 6 and Big Cajun 2 Unit 3 to avoid the environmental compliance costs? To the extent Mr. Pollock disagrees in whole or in part, provide all support for his position.

Response:

No. The decision to deactivate, retire, or continue operations at Nelson 6 and Big Cajun 2 Unit 3 should be driven by economics. That is, deactivation or early retirement should only be pursued if the economics show that the benefits of deactivation or early retirement significantly outweigh the full costs of continued operation over the unit's lifespan. ETI failed to demonstrate that deactivating these units is a compelling cost-efficient opportunity, as discussed in Mr. Pollock's direct testimony.

Preparer: Jeffry Pollock
Sponsor: Jeffry Pollock

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ETI-TIEC 3-12

Referring to Mr. Griffey's testimony at page 5, please provide a copy of the referenced "analysis that demonstrated differences in electric rates between Reliant Energy and City Public Service of San Antonio ('CPS')."

Response:

Mr. Griffey was describing previous analysis that had been done by him or under his supervision while he was at Reliant. Mr. Griffey no longer has access to this analysis.

Preparer: Charles S. Griffey
Sponsor: Charles S. Griffey

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TEXAS INDUSTRIAL ENERGY CONSUMERS' RESPONSE TO ENTERGY TEXAS, INC.'S THIRD REQUEST FOR INFORMATION

ETI-TIEC 3-13

Referring to Mr. Griffey's testimony at page 16, please provide a copy of the referenced "benchmarking analysis of O&M costs for residential and small commercial customers circa 2005."

Response: Please see the response to ETI-TIEC 3-12.

Preparer: Charles S. Griffey
Sponsor: Charles S. Griffey

DOCKET NO. 160062-EI
Docket No. 160021-EI
2016 Depreciation Study
Exhibit NWA-1, Page 1 of 762

FLORIDA POWER AND LIGHT COMPANY

JUNO BEACH, FLORIDA

FILED MAR 15, 2016
DOCUMENT NO. 01415-16
FPSC - COMMISSION

DEPRECIATION STUDY

CALCULATED ANNUAL DEPRECIATION ACCRUALS RELATED TO ELECTRIC PLANT AS OF DECEMBER 31, 2017

Prepared by:

Gannett Fleming

Excellence Delivered ***As Promised*** based on a number of factors, including the operating characteristics of the facilities, the type of technology used at each plant, environmental and other regulations, experience in the industry, current forecasted life spans, and the Company's outlook for each facility.

A description of each generating facility, as well as the bases for the estimated probable retirement dates and estimated interim survivor curves can be found in the section beginning on page X-2. Generally, the recommended retirement dates are consistent with 50 year life spans for the Company's steam units, 60 year life spans for the Company's nuclear units, 40 year life spans for the Company's combined cycle and new peaker units, and 30 year life spans for the Company's solar units. The probable retirement dates used in this study for each of the production facilities are summarized below. The same retirement date was used for each unit at the facility unless otherwise noted.

GENERATING PLANT	PROBABLE RETIREMENT DATE
STEAM PRODUCTION	
Manatee	2028
Martin	2031
Scherer	2039
St. Johns River Power Park	2038
NUCLEAR PRODUCTION	
St. Lucie Common	2043
St. Lucie Unit 1	2036
St. Lucie Unit 2	2043
Turkey Point Common	2033
Turkey Point Unit 3	2032
Turkey Point Unit 4	2033

OTHER PRODUCTION

Combined Cycle	
Lauderdale	2033
Ft. Myers	2043
Manatee	2045
Martin Units 3 and 4	2034
Martin Unit 8	2045
Sanford Common	2043
Sanford Unit 4	2043
Sanford Unit 5	2042
Turkey Point	2047
West County Common	2051
West County Units 1 and 2	2049
West County Unit 3	2051
Cape Canaveral	2053
Riviera	2054
Pt. Everglades	2056
Peaker Plants	
Lauderdale Gas Turbines	2028
Ft. Myers Gas Turbines	2028
Lauderdale and Ft. Myers CTs	2056
Solar	
DeSoto	2039
Space Coast	2040
Martin Solar	2045
Babcock Ranch	2046
Manatee Solar	2046
Citrus Solar	2046

FPL

Ten Year Power Plant Site Plan

2019-2028

Submitted To:

Florida Public
Service Commission

April 2019

Schedule 1

Existing Generating Facilities
As of December 31, 2018

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Plant Name	Unit No.	Location	Unit Type	Fuel Pri.	Fuel Alt.	Fuel Transport Pri.	Fuel Transport Alt.	Alt. Fuel Days Use	Commercial In-Service Month/Year	Actual/ Expected Retirement Month/Year	Gen. Max. Nameplate KW	Net Capability [1/] Winter MW	Net Capability [1/] Summer MW
Babcock Ranch Solar [2/]		Charlotte County											
		19,30,31/42S/26E									74,500	74.5	74.5
	1		PV	Solar	Solar	N/A	N/A	Unknown	Dec-16	Unknown	74,500	74.5	74.5
Barefoot Solar [2/]		Brevard County											
		15,16/30S/38E									74,500	74.5	74.5
	1		PV	Solar	Solar	N/A	N/A	Unknown	Mar-18	Unknown	74,500	74.5	74.5
Blue Cypress Solar [2/]		Indian River County											
		16,21/33S/38E									74,500	74.5	74.5
	1		PV	Solar	Solar	N/A	N/A	Unknown	Mar-18	Unknown	74,500	74.5	74.5
Cape Canaveral		Brevard County											
		19/24S/36E									1,295,400	1,378	1,257
	3		CC	NG	FO2	PL	TK	Unknown	Apr-13	Unknown	1,295,400	1,378	1,257
Citrus Solar [2/]		DeSoto County											
		18,19/33S/20E									74,500	74.5	74.5
	1		PV	Solar	Solar	N/A	N/A	Unknown	Dec-16	Unknown	74,500	74.5	74.5
Coral Farms Solar [2/]		Putnam County											
		27,28,33,34/8S/24E: 3,9S/24E									74,500	74.5	74.5
	1		PV	Solar	Solar	N/A	N/A	Unknown	Jan-18	Unknown	74,500	74.5	74.5
DeSoto [2/]		DeSoto County											
		25,26/36S/25E									22,500	25	25
	1		PV	Solar	Solar	N/A	N/A	Unknown	Oct-09	Unknown	22,500	25	25
Fort Myers		Lee County											
		35/43S/25E									2,680,890	2,709	2,533
	2		CC	NG	No	PL	No	Unknown	Jun-02	Unknown	1,721,490	1,746	1,573
	3		CT	NG	FO2	TK	TK	Unknown	Jun-03	Unknown	835,380	840	852
	1, 9		GT	FO2	No	WA	No	Unknown	May-74	Unknown	124,020	123	108
Hammock Solar [2/]		Hendry County											
		33,34/43S/30E: 3,4,9,10/44S/30E									74,500	74.5	74.5
	1		PV	Solar	Solar	N/A	N/A	Unknown	Mar-18	Unknown	74,500	74.5	74.5
Horizon Solar [2/]		Putnam and Alachua Counties											
		30,31/33S/38E (Putnam) : 25,35,36/9S/22E (Alachua)									74,500	74.5	74.5
	1		PV	Solar	Solar	N/A	N/A	Unknown	Jan-18	Unknown	74,500	74.5	74.5
Indian River Solar [2/]		Indian River County											
		30,31/33S/38E									74,500	74.5	74.5
	1		PV	Solar	Solar	N/A	N/A	Unknown	Jan-18	Unknown	74,500	74.5	74.5
Lauderdale		Broward County											
		19,20,25,30/50S/41,42E									1,215,956	1,184	1,224
	6		CT	NG	FO2	PL	TK	Unknown	Dec-16	Unknown	1,147,500	1,110	1,155
	3, 5		GT	NG	FO2	PL	TK	Unknown	Aug-70	Unknown	68,456	74	69
Loggerhead Solar [2/]		St. Lucie County											
		21,33,28/37S/38E									74,500	74.5	74.5
	1		PV	Solar	Solar	N/A	N/A	Unknown	Mar-18	Unknown	74,500	74.5	74.5
Manatee Solar [2/]		Manatee County											
		19/33S/20E									74,500	74.5	74.5
	1		PV	Solar	Solar	N/A	N/A	Unknown	Dec-16	Unknown	74,500	74.5	74.5

1/ These ratings are peak capability.

2/ Approximately 54% of the 74.5 MW PV facility at Coral Farms, Horizon, Indian River, Hammock, Barefoot Bay, Blue Cypress, and Loggerhead, 52% of the 74.5 MW PV Facility at Babcock Ranch, Citrus, and Manatee and 45% of the 25 MW PV facility at Desoto is considered as firm generating capacity for Summer reserve margin purposes and 0% is considered as firm capacity for Winter reserve margin purposes.

Schedule 1

Existing Generating Facilities
As of December 31, 2018

(1) Plant Name	(2) Unit No.	(3) Location	(4) Unit Type	(5) Fuel Pri.	(6) Fuel Alt.	(7) Fuel Transport Pri.	(8) Fuel Transport Alt.	(9) Alt. Fuel Days Use	(10) Commercial In-Service Month/Year	(11) Actual/ Expected Retirement Month/Year	(12) Gen.Max. Nameplate KW	(13) Net Capability [1/] Winter MW	(14) Net Capability [1/] Summer MW
Manatee		Manatee County											
		18/33S/20E									2,951,110	2,903	2,751
	1		ST	NG	FO6	PL	WA	Unknown	Oct-76	Unknown	863,300	819	809
	2		ST	NG	FO6	PL	WA	Unknown	Dec-77	Unknown	863,300	819	809
	3		CC	NG	No	PL	No	Unknown	Jun-05	Unknown	1,224,510	1,265	1,133
Martin		Martin County											
		29/39S/38E									2,448,510	2,337	2,209
	3		CC	NG	No	PL	No	Unknown	Feb-94	Unknown	612,000	533	487
	4		CC	NG	No	PL	No	Unknown	Apr-94	Unknown	612,000	533	487
	8 [4/]		CC	NG	FO2	PL	TK	Unknown	Jun-05	Unknown	1,224,510	1,271	1,235
Port Everglades		City of Hollywood											
		23/50S/42E									1,412,700	1,338	1,237
	5		CC	NG	FO2	PL	TK	Unknown	Apr-16	Unknown	1,412,700	1,338	1,237
Riviera Beach		City of Riviera Beach											
		33/42S/432E									1,295,400	1,393	1,290
	5		CC	NG	FO2	PL	TK	Unknown	Apr-14	Unknown	1,295,400	1,393	1,290
Sanford		Volusia County											
		16/19S/30E									2,377,720	2,281	2,046
	4		CC	NG	No	PL	No	Unknown	Oct-03	Unknown	1,188,860	1,147	1,029
	5		CC	NG	No	PL	No	Unknown	Jun-02	Unknown	1,188,860	1,134	1,017
Scherer [2/]		Monroe, GA									680,368	635	634
	4		ST	SUB	No	RR	No	Unknown	Jul-89	Unknown	680,368	635	634
Space Coast [3/]		Brevard County											
		13/23S/36E									10,000	10	10
	1		PV	Solar	Solar	N/A	N/A	Unknown	Apr-10	Unknown	10,000	10	10
St. Lucie [5/]		St. Lucie County											
		16/36S/41E									1,999,128	1,863	1,821
	1		ST	Nuc	No	TK	No	Unknown	May-76	Unknown	1,080,000	1,003	981
	2		ST	Nuc	No	TK	No	Unknown	Jun-83	Unknown	919,128	860	840
Turkey Point		Miami Dade County											
		27/57S/40E									2,978,910	2,960	2,825
	3		ST	Nuc	No	TK	No	Unknown	Nov-72	Unknown	877,200	859	837
	4		ST	Nuc	No	TK	No	Unknown	Jun-73	Unknown	877,200	848	821
	5		CC	NG	FO2	PL	TK	Unknown	May-07	Unknown	1,224,510	1,253	1,167
West County		Palm Beach County											
		29&32/43S/40E									4,100,400	4,027	3,692
	1		CC	NG	FO2	PL	TK	Unknown	Aug-09	Unknown	1,366,800	1,369	1,259
	2		CC	NG	FO2	PL	TK	Unknown	Nov-09	Unknown	1,366,800	1,309	1,195
	3		CC	NG	FO2	PL	TK	Unknown	May-11	Unknown	1,366,800	1,349	1,238
Wildflower Solar [3/]		Desoto County											
		25,26/36S/25E									74,500	74.5	74.5
	1		PV	Solar	Solar	N/A	N/A	Unknown	Jan-18	Unknown	74,500	74.5	74.5
										Total System Generating Capacity as of December 31, 2018 [6/] =		**25,862**	**24,373**
										System Firm Generating Capacity as of December 31, 2018 [7/] =		**25,008**	**23,970**

1/ These ratings are peak capability.
2/ These ratings relate to FPL's 76.36% share of Plant Scherer Unit 4 operated by Georgia Power, and represent FPL's 73.923% ownership share available at point of interchange.
3/ Approximately 54% of the 74.5 MW PV facility at Wildflower, and 31% of the 10 MW PV facility at Space Coast is considered as firm generating capacity for Summer reserve margin purposes and 0% is considered as firm capacity for Winter reserve margin purposes.
4/ Martin Unit 8 is also partially fueled by a 75 MW solar thermal facility that supplies steam when adequate sunlight is available, thus reducing fossil fuel use.
5/ Total capability of St. Lucie 1 is 981/1,003 MW. FPL's share of St. Lucie 2 is 840/860.FPL's ownership share of St. Lucie Units 1 and 2 is 100% and 85%, respectively, as shown above. FPL's share of the deliverable capacity from each unit is approx. 92.5% and exclude the Orlando Utilities Commission (OUC) and Florida Municipal Power Agency (FMPA) combined portion of approximately 7.448% per unit.
6/ The Total System Generating Capacity value shown includes FPL-owned firm and non-firm generating capacity.
7/ The System Firm Generating Capacity value shown includes only firm generating capacity.

UPPER MIDWEST INTEGRATED RESOURCE PLAN

2020-2034

Northern States Power Company
Docket No. E002/RP-19-368

Table 3: Existing Natural Gas and Oil Resources

Name of Unit or Contract	Type	Owned or Contracted (PPA)	Capacity	Existing or Planned Retirement/Contract Expiration
Black Dog 52	CC	Own	298	2032
High Bridge	CC	Own	606	2048
Riverside	CC	Own	508	2049
Mankato Energy Center[3]	CC	Own	762	2046, 2054
LSP – Cottage Grove	CC	PPA	245	2027
Angus Anson 2-4	CT	Own	386	2034
Black Dog 6	CT	Own	232	2058
Blue Lake 7,8	CT	Own	351	2034
Inver Hills 1-6	CT	Own	369	2026
Wheaton 1-4	CT	Own	241	2025
Cannon Falls Energy Center	CT	PPA	358	2025
Blue Lake 1-4	Oil	Own	191	2023
French Island 3,4	Oil	Own	160	2027
Wheaton 6	Oil	Own	70	2025

D. Biomass

The company owns and operates, and maintains PPAs with, various biomass facilities. Refuse-derived fuel (RDF), landfill (LND) and digester (DIGT) resources are also generally considered biomass resources and therefore included in this category. These facilities total nearly 160 MW of capacity on our system.

[3] Note: As stated above, we have modeled Mankato Energy Center as an owned resource. Approval of this acquisition is pending in Docket No. IP6949, E002/PA-18-702.

Name of Unit or Contract	Type	Owned or Contracted PPA	Capacity	Existing or Planned Retirement/Contract Expiration	In-Service Month	In-Service Year
Black Dog 52	CC	Own	298	2032	6	2002
High Bridge	CC	Own	606	2048	5	2008
Riverside	CC	Own	508	2049	4	2009
Mankato Energy Center	CC	Own	762	2046, 2054	7	2006
LSP - Cottage Grove	CC	PPA	245	2027	10	1997

PUC Docket No. 46449
Schedule D-6

SOUTHWESTERN ELECTRIC POWER COMPANY
Retirement Data For All Generating Units
For the Test Year Ended June 30, 2016

	(1)	(2)	(3)	(4)	(5)	(6)
Line No.	Unit Name	Net Dependable Capability (MW)	In-Service Date	Service Life (Years)	Depreciation Retirement Date	Planning Retirement Date
1	*GAS & OIL UNITS*					
2	Arsenal Hill					
3	Unit 5	110	1960	65	2025	2025
4	Knox Lee					
5	Unit 2	30	1950	70	2020	2020
6	Unit 3	25	1952	68	2020	2020
7	Unit 4	79	1956	63	2019	2019
8	Unit 5	342	1974	65	2039	2039
9	Lieberman					
10	Unit 2	26	1949	70	2019	2019
11	Unit 3	109	1957	65	2022	2022
12	Unit 4	108	1959	65	2024	2024
13	Lone Star					
14	Unit 1	50	1954	65	2019	2019
15	Mattison					
16	Unit 1	76	2007	45	2052	2052
17	Unit 2	76	2007	45	2052	2052
18	Unit 3	76	2007	45	2052	2052
19	Unit 4	76	2007	45	2052	2052
20	Wilkes					
21	Unit 1	177	1964	65	2029	2029
22	Unit 2	362	1970	65	2035	2035
23	Unit 3	362	1971	65	2036	2036
24	Stall Unit at Arsenal Hill	500	2010	40	2050	2050
25	*COAL & LIGNITE UNITS*					
26	Dolet Hills					
27	Unit 1	262	1986	50	2036	2036
28	Flint Creek					
29	Unit 1	264	1978	60	2038	2038
30	Pirkey					
31	Unit 1	580	1985	60	2045	2045
32	Turk					
33	Unit 1	440	2012	55	2067	2067
34	Welsh					
35	Unit 1	528	1977	60	2037	2037
36	Unit 3	528	1982	60	2042	2042

Note: Lieberman Unit 1 was retired in December 2014 and Welsh Unit 2 was retired in April 2016.

Sponsored by: Paul Franklin

GEORGIA POWER
CURRENT AND PROPOSED GENERATING UNIT RETIREMENT DATES

Location	Unit	Current Retirement Year	Proposed Retirement Year	Difference
1282, 1287, & 1288	McIntosh CT Units 5-6	2039	2039	0
1348	Mcintosh 7	2039	2039	0
1349	Mcintosh 8	2039	2039	0
1330	McManus CT	2017	2022	5
1345	Warner Robins CT Common	2040	2040	0
1346	Warner Robins CT Unit 1	2040	2040	0
1347	Warner Robins CT Unit 2	2040	2040	0
1332	Wansley CT	2025	2025	0
1333	Wilson CT	2018	2022	4
1300	McDonough CC Common	NA	2058	NA
1301	McDonough CC Unit 4	NA	2057	NA
1302	McDonough CC Unit 5	NA	2057	NA
1303	McDonough CC Unit 6	NA	2058	NA
1278	McIntosh CC Common	2040	2050	10
1279	McIntosh CC Unit 10	2040	2050	10
1280	McIntosh CC Unit 11	2040	2050	10
1334	Dalton Solar	NA	2036	NA
1313, 1314, & 1315	Falcon Project	NA	2045	NA
1306	Fort Benning Solar	NA	2050	NA
1304	Fort Gordon Solar	NA	2051	NA
1305	Fort Stewart Solar	NA	2051	NA
1307	Kings Bay Navy Base Solar	NA	2051	NA
1316	Tri-County Solar	NA	2041	NA
1308	UGA Solar	NA	2036	NA

McIntosh Combined Cycle | Power Plant Units

	MCINTOSH CC CC 10ST	MCINTOSH CC CC 11ST	MCINTOSH CC CC C10A	MCINTOSH CC CC C10B	MCINTOSH CC CC C11A	MCINTOSH CC CC C11B
Generator Information						
Prime Mover	Combined Cycle (CC)	Combined Cycle (CC)	Combined Cycle (CC)	Combined Cycle (CC)	Combined Cycle (CC)	Combined Cycle (CC)
Generation Technology	Combined Cycle Combustion Steam (CA)	Combined Cycle Combustion Steam (CA)	Combined Cycle Combustion Turbine (CT)	Combined Cycle Combustion Turbine (CT)	Combined Cycle Combustion Turbine (CT)	Combined Cycle Combustion Turbine (CT)
Generation Technology Detail	-	-	-	-	-	-
Current Development Status	Operating	Operating	Operating	Operating	Operating	Operating
In-Service Month and Year	6/2005	6/2005	6/2005	6/2005	6/2005	6/2005
Retirement Month and Year	-	-	-	-	-	-
Nameplate Capacity (MW)	281.9	281.9	203.2	203.2	203.2	203.2
Summer Net Capacity (MW)	295.0	295.0	183.0	183.0	181.3	181.3
Winter Net Capacity (MW)	295.0	295.0	196.5	196.5	195.0	195.0
Energy Pricing Node or Zone	-	-	-	-	-	-
Self-Generator?	No	No	No	No	No	No
Turbine Information						
Manufacturer	Alstom Power Inc.	Alstom Power Inc.	GE Energy	GE Energy	GE Energy	GE Energy
Turbine Type	SPT 35	SPT 35	7F.04	7F.04	7F.04	7F.04
Owner Information						
Owner/Ultimate Owner/Percent Owned	Georgia Power Co./Southern Co. (100.00%)	Georgia Power Co./Southern Co. (100.00%)	Georgia Power Co./Southern Co. (100.00%)	Georgia Power Co./Southern Co. (100.00%)	Georgia Power Co./Southern Co. (100.00%)	Georgia Power Co./Southern Co. (100.00%)
Fuel Data						
Primary Fuel	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas
Secondary Fuel	Distillate Fuel Oil	Distillate Fuel Oil	Distillate Fuel Oil	Distillate Fuel Oil	Distillate Fuel Oil	Distillate Fuel Oil
Additional Fuel Type(s)	Waste Heat	Waste Heat	-	-	-	-

S&P Global
Market Intelligence

Jack McDonough CC | Power Plant Units

	JACK MCDONOUGH CC 4	JACK MCDONOUGH CC 5	JACK MCDONOUGH CC 5ACT	JACK MCDONOUGH CC 5BCT	JACK MCDONOUGH CC 6	JACK MCDONOUGH CC 6ACT	JACK MCDONOUGH CC 6BCT	JACK MCDONOUGH CC CT4A	JACK MCDONOUGH CC CT4B
Generator Information									
Prime Mover	Combined Cycle (CC)	Combined Cycle (CC)	Combined Cycle (CC)	Combined Cycle (CC)	Combined Cycle (CC)	Combined Cycle (CC)	Combined Cycle (CC)	Combined Cycle (CC)	Combined Cycle (CC)
Generation Technology	Combined Cycle Combustion Steam (CA)	Combined Cycle Combustion Steam (CA)	Combined Cycle Combustion Turbine (CT)	Combined Cycle Combustion Turbine (CT)	Combined Cycle Combustion Steam (CA)	Combined Cycle Combustion Turbine (CT)	Combined Cycle Combustion Turbine (CT)	Combined Cycle Combustion Turbine (CT)	Combined Cycle Combustion Turbine (CT)
Generation Technology Detail	-	-	-	-	-	-	-	-	-
Current Development Status	Operating	Operating	Operating	Operating	Operating	Operating	Operating	Operating	Operating
In-Service Month and Year	12/2011	4/2012	4/2012	4/2012	10/2012	10/2012	10/2012	12/2011	12/2011
Retirement Month and Year	-	-	-	-	-	-	-	-	-
Nameplate Capacity (MW)	375.0	375.0	232.5	232.5	375.0	232.5	232.5	232.5	232.5
Summer Net Capacity (MW)	360.0	360.0	231.5	231.5	360.0	233.0	233.0	230.5	230.5
Winter Net Capacity (MW)	360.0	360.0	273.5	273.5	360.0	275.0	275.0	272.5	272.5
Energy Pricing Node or Zone	-	-	-	-	-	-	-	-	-
Self-Generator?	No	No	No	No	No	No	No	No	No
Turbine Information									
Manufacturer	Toshiba Corp.	Toshiba Corp.	Mitsubishi Heavy Industries	Mitsubishi Heavy Industries	Toshiba Corp.	Mitsubishi Heavy Industries	Mitsubishi Heavy Industries	Mitsubishi Heavy Industries	Mitsubishi Heavy Industries
Turbine Type	TCDF 40 FLEB	TCDF 40 FLEB	501 G1	501 G1	TCDF 40 FLEB	501 G1	501 G1	501 G1	501 G1
Owner Information									
Owner/Ultimate Owner/Percent Owned	Georgia Power Co./Southern Co. (100.00%)	Georgia Power Co./Southern Co. (100.00%)	Georgia Power Co./Southern Co. (100.00%)	Georgia Power Co./Southern Co. (100.00%)	Georgia Power Co./Southern Co. (100.00%)	Georgia Power Co./Southern Co. (100.00%)	Georgia Power Co./Southern Co. (100.00%)	Georgia Power Co./Southern Co. (100.00%)	Georgia Power Co./Southern Co. (100.00%)

	HIGH BRIDGE CC 7	HIGH BRIDGE CC 8	HIGH BRIDGE CC 9
Generator Information			
Prime Mover	Combined Cycle (CC)	Combined Cycle (CC)	Combined Cycle (CC)
Generation Technology	Combined Cycle Combustion Turbine (CT)	Combined Cycle Combustion Turbine (CT)	Combined Cycle Combustion Steam (CA)
Generation Technology Detail	-	-	-
Current Development Status	Operating	Operating	Operating
In-Service Month and Year	5/2008	5/2008	5/2008
Retirement Month and Year	-	-	-
Nameplate Capacity (MW)	197.0	197.0	250.0
Summer Net Capacity (MW)	152.0	152.0	226.0
Winter Net Capacity (MW)	185.0	185.0	236.0
Energy Pricing Node or Zone	-	-	-
Self-Generator?	No	No	No
Turbine Information			
Manufacturer	Mitsubishi Power Systems	Mitsubishi Power Systems	Mitsubishi Power Systems
Turbine Type	M501F	M501F	-
Owner Information			
Owner/Ultimate Owner/Percent Owned	Northern States Power Co. - MN/Xcel Energy Inc. (100.00%)	Northern States Power Co. - MN/Xcel Energy Inc. (100.00%)	Northern States Power Co. - MN/Xcel Energy Inc. (100.00%)
Fuel Data			
Primary Fuel	Natural Gas	Natural Gas	Natural Gas
Secondary Fuel	-	-	Waste Heat
Additional Fuel Type(s)	-	-	-

Riverside Generating Station

Key facts:

- **Power Production Capability:** Total 454 megawatts
  Unit 7A – 160 MW; Unit 9 – 147 MW; Unit 10 – 147 MW
- **Commercial Operation:** 2009
- **Generation type:** Combined cycle
- **Location:** On the Mississippi River in Minneapolis, Minnesota

Overview

Built in 1911, the original coal-powered station was the oldest in the Xcel Energy system. Although construction crews used primitive tools and horse-drawn equipment to build the plant, Unit 1 was up and running within 18 weeks after construction began. As Minneapolis grew, so did the Riverside plant. By 1966, Riverside had eight operating units and a net capability of 512 megawatts.

The original plant was replaced with a new natural gas fired facility starting in 2006 as part of our Metro Emissions Reduction Project to significantly reduce air emissions and increase electricity production. The coal-fired plant was retired as the new combined cycle facility came on line in April 2009.

S&P Global
Market Intelligence

Mankato Power Plant | Power Plant Units

	MANKATO POWER PLANT CC CTG1	MANKATO POWER PLANT CC CTG2	MANKATO POWER PLANT CC STG1
Generator Information			
Prime Mover	Combined Cycle (CC)	Combined Cycle (CC)	Combined Cycle (CC)
Generation Technology	Combined Cycle Combustion Turbine (CT)	Combined Cycle Combustion Turbine (CT)	Combined Cycle Combustion Steam (CA)
Generation Technology Detail	-	-	-
Current Development Status	Operating	Operating	Operating
In-Service Month and Year	6/2019	7/2006	7/2006
Retirement Month and Year	-	-	-
Nameplate Capacity (MW)	200.0	210.0	320.0
Summer Net Capacity (MW)	200.0	174.0	156.0
Winter Net Capacity (MW)	200.0	187.0	190.0
Energy Pricing Node or Zone	-	-	-
Self-Generator?	No	No	No
Turbine Information			
Manufacturer	-	Siemens-Westinghouse Inc	Toshiba Power Systems Co
Turbine Type	-	501FD2	TCDF
Owner Information			
Owner/Ultimate Owner/Percent Owned	SW Generation Operating Co LLC/IIF US Holding GP (100.00%)	SW Generation Operating Co LLC/IIF US Holding GP (100.00%)	SW Generation Operating Co LLC/IIF US Holding GP (100.00%)
Fuel Data			
Primary Fuel	Natural Gas	Natural Gas	Natural Gas
Secondary Fuel	-	Distillate Fuel Oil	Distillate Fuel Oil

	LAMAR STALL - ARSENAL HILL CC 6A	LAMAR STALL - ARSENAL HILL CC 6B	LAMAR STALL - ARSENAL HILL CC 6STG
Generator Information			
Prime Mover	Combined Cycle (CC)	Combined Cycle (CC)	Combined Cycle (CC)
Generation Technology	Combined Cycle Combustion Turbine (CT)	Combined Cycle Combustion Turbine (CT)	Combined Cycle Combustion Steam (CA)
Generation Technology Detail	-	-	-
Current Development Status	Operating	Operating	Operating
In-Service Month and Year	6/2010	6/2010	6/2010
Retirement Month and Year	-	-	-
Nameplate Capacity (MW)	184.0	184.0	256.0
Summer Net Capacity (MW)	160.0	160.0	187.0
Winter Net Capacity (MW)	184.0	184.0	201.0
Energy Pricing Node or Zone	-	-	-
Self-Generator?	No	No	No
Turbine Information			
Manufacturer	Siemens Power Generation	Siemens Power Generation	GE Energy
Turbine Type	W501FD2	W501FD2	D-11
Owner Information			
Owner/Ultimate Owner/Percent Owned	Southwestern Electric Power Co/American Electric Power Co. (100.00%)	Southwestern Electric Power Co/American Electric Power Co. (100.00%)	Southwestern Electric Power Co/American Electric Power Co. (100.00%)
Fuel Data			
Primary Fuel	Natural Gas	Natural Gas	Natural Gas
Secondary Fuel	-	-	Waste Heat

BEFORE THE
ALABAMA PUBLIC SERVICE COMMISSION

Alabama Power Company

PETITION: For a certificate of convenience and necessity for: (i) the construction and installation of combined cycle generating capacity at the site of Petitioner's Barry Steam Plant located in Mobile County, Alabama; (ii) the acquisition of existing combined cycle generating capacity in Autauga County, Alabama; (iii) the acquisition of rights and the assumption of payment obligations under a purchased power agreement for the output of combined cycle generating capacity operated in Mobile County, Alabama; and (iv) the acquisition of rights and the assumption of payment obligations under purchased power agreements for the output from five solar photovoltaic and battery energy storage systems, located in Calhoun, Chambers, Dallas, Houston and Talladega Counties; together with all transmission arrangements, structures, substations, and facilities, environmental control measures, facilities or arrangements for the handling, treatment, transportation, delivery and processing of fuel, and any and all other appliances, appurtenances, facilities, rights, equipment, acquisitions, commitments and accounting authorizations necessary for or incident thereto.

Docket No. ___________

(Confidential Version – Subject to Non-Disclosure Agreement)

VOLUME I

Petition

John B. Kelley Testimony and Exhibits JBK-1 – JBK-6

1710 Sixth Avenue North • P.O. Box 306 (35201) • Birmingham, AL 35203-2015 www.balch.com

BALCH
& BINGHAM LLP

DAN H. MCCRARY
t: (205) 226-3409
f: (205) 488-5886
e: dmccrary@balch.com

September 6, 2019

Alabama Public Service Commission
RSA Union Building
100 North Union Street, Suite 950
Montgomery, Alabama 36104

Attention: Mr. Walter L. Thomas, Jr.
Secretary

Re: Petition for a Certificate of Convenience and Necessity
Docket No. __________

Dear Secretary Thomas,

On behalf of Alabama Power Company, we are submitting for filing the enclosed petition for a certificate of convenience and necessity, along with supporting testimony and exhibits. As the supporting materials include information that is confidential and proprietary to the Company and to third parties, we are providing a version for public posting along with a non-public confidential version to be retained under seal by the Commission. Also enclosed is a Confidentiality Agreement for interested parties that are permitted to intervene in the proceeding and who desire access to the non-public confidential materials under the terms and conditions set forth in said agreement. Lastly, the Company is providing a proposed form of notice.

If you have questions concerning any aspect of the Company's filing, please contact the undersigned.

Very truly yours,

Dan H. McCrary

Dan H. McCrary

DHM:eb

Encl.

ALABAMA POWER COMPANY,

Petitioner

PETITION: For a certificate of convenience and necessity for: (i) the construction and installation of combined cycle generating capacity at the site of Petitioner's Barry Steam Plant located in Mobile County, Alabama; (ii) the acquisition of existing combined cycle generating capacity in Autauga County, Alabama; (iii) the acquisition of rights and the assumption of payment obligations under a power purchase agreement for the output of combined cycle generating capacity operated in Mobile County, Alabama; and (iv) the acquisition of rights and the assumption of payment obligations under power purchase agreements for the output from five solar photovoltaic and battery energy storage systems, located in Calhoun, Chambers, Dallas, Houston and Talladega Counties; together with all transmission arrangements, structures, substations, and facilities, environmental control measures, facilities or arrangements for the handling, treatment, transportation, delivery and processing of fuel, and any and all other appliances, appurtenances, facilities, rights, equipment, acquisitions, commitments and accounting authorizations necessary for or incident thereto.

Docket No. __________

TO THE ALABAMA PUBLIC SERVICE COMMISSION:

Alabama Power Company ("Petitioner" or "Company") hereby requests, pursuant to Alabama Code § 37-4-28 and Parts A and B of Rate CNP–Adjustment for Commercial Operation of Certificated New Plant, that the Commission issue an order in this proceeding granting a certificate of convenience and necessity ("Certificate"). By the Certificate, as described in this Petition and in the testimony and exhibits filed in support thereof, the Commission would authorize the Company to: (i) construct and install combined cycle generating capacity at the site of the Petitioner's Barry Steam Plant located in Mobile County, Alabama; (ii) acquire the Central Alabama Generating Station, a combined cycle generating facility located in Autauga County, Alabama; (iii) acquire rights and assume payment obligations under a power purchase agreement ("PPA") pertaining to the Hog Bayou Energy Center, a combined cycle generating facility located in Mobile County, Alabama; and (iv) acquire rights and assume payment obligations under five PPAs pertaining to solar photovoltaic facilities, each being paired with a battery energy storage system ("BESS"), as located in Calhoun, Chambers, Dallas, Houston and Talladega Counties. In addition to the requested authority under the Certificate, the Company is seeking authorization to pursue approximately 200 MW of demand-side management and distributed energy resource programs.

In support of its Petition, the Company states as follows:

1. Petitioner is a corporation organized and existing under the laws of the State of Alabama that owns and operates electric generating plants and has other sources of supply of electric power, all of which are connected by or delivered to transmission lines and facilities forming the Company's interconnected electrical system. Petitioner is engaged as a public utility in the distribution and sale to the public of the electricity so produced and acquired by it, and such utility service is furnished by Petitioner to the public in a large section of the State.

2. In order to meet the demand for electricity in the territory served by the Company and to render adequate and reliable service to the public, as contemplated under Title 37 of the Code of Alabama, it is necessary and appropriate for the Company to make the following additions to its portfolio of supply resources.[1]

[1] The Company's reliability-based need for additional resources is addressed in the supporting testimony and exhibits of John B. Kelley and Jeffrey B. Weathers.

3. Petitioner proposes to construct and install combined cycle generating capacity at the site of Petitioner's Barry Steam Plant located in Mobile County, Alabama ("Barry Unit 8").[2] Barry Unit 8 will initially provide approximately 726 MW of winter-rated capacity (increasing to approximately 743 MW of winter-rated capacity under a subsequent uprate), with an expected useful life of 40 years. Commercial operation is expected in November, 2023. The principal components of Barry Unit 8 include one Mitsubishi 501 J-series air-cooled combustion turbine, one heat recovery steam generator with duct firing, and one condensing reheat steam turbine (together comprising a 1-on-1 combined cycle configuration), along with other balance of plant equipment, including a cooling tower for closed-cycle cooling operations. The unit will be constructed under a turnkey Agreement for Engineering, Procurement and Construction with Mitsubishi Hitachi Power Systems Americas, Inc. and Black & Veatch Construction, Inc. The project will take maximum advantage of existing infrastructure at the Plant Barry site, but some infrastructure additions will be required, such as a new tie line to the existing adjacent Ellicott 230 kV substation, a gas extension line from the existing Plant Barry gas yard to the location of the new unit, and new water lines and access roads.

4. Petitioner proposes to acquire the Central Alabama Generating Station ("Central Alabama") located in Autauga County, Alabama.[3] Central Alabama is a combined cycle facility constructed in 2003, with an estimated remaining life (post-closing) of approximately 23 years. The facility, which has a winter capacity rating of 915 MW and a summer capacity rating of 890 MW, is owned by Tenaska Alabama II Partners, L.P. (the "Partnership"), a Delaware limited partnership in which a Tenaska subsidiary is the managing general partner and majority owner.

[2] Barry Unit 8 is addressed in the supporting testimony and exhibits of Michael A. Bush.

[3] The acquisition of Central Alabama, as well as the associated PPA that expires in mid-2023, is addressed in the supporting testimony and exhibits of John B. Kelley.

Upon the closing of a Purchase and Sale Agreement, the Company will hold a 100 percent interest in the Partnership, after which all rights, title and interest of the Partnership in its assets (Central Alabama, along with related assets and properties) will be transferred into Petitioner. Until May 2023, Central Alabama is subject to a PPA with a third party under which the third party is entitled to the capacity of the facility and the associated energy. The third-party PPA will remain in place until it expires, with the Company entitled to receive the associated revenues. Petitioner will thereafter have the same rights and responsibilities associated with Central Alabama as with any other generating facility that it owns.

5. Petitioner proposes to acquire rights and assume payment obligations under a PPA with Mobile Energy, LLC whereby the Company will be entitled to the entire capability of the Hog Bayou Energy Center located in Mobile County, Alabama, for a total term of approximately 19 years.[4] The Hog Bayou Energy Center is a combined cycle, natural-gas fired facility with a summer rating of 222 MW and a winter rating of 238 MW. In order to address certain near-term reliability needs of the Company, the PPA calls for an early start period beginning in 2020 through November 2023, followed by a 15-year term beginning in December 2023. Along with monthly capacity payments, the Company is responsible for an energy payment that includes a charge for each unit start, plus a charge for variable O&M expenses and a fuel adjustment based on a guaranteed heat rate. As this is a "tolling" PPA, the Company is separately responsible for the fuel-related arrangements (commodity and transportation).

6. Petitioner proposes to acquire rights and assume payment obligations under 28-year PPAs with five separate projects to be located in Calhoun, Chambers, Dallas, Houston and

[4] The PPA associated with the Hog Bayou Energy Center is addressed in the supporting testimony and exhibits of John B. Kelley.

Talladega Counties.[5] Each project comprises a nominal 80 MW solar photovoltaic facility and a nominal 80 MW BESS that, given operational parameters, yield a cumulative winter capacity equivalence of 340 MW (68 MW per project). Although the payment structure for each of these five PPAs bundles both solar- and BESS-related costs into a single combined energy payment, a portion of that combined energy payment is attributable to the cost of the BESS component that provides capacity to the Company.

7. Along with the above-described supply resources, Petitioner is requesting authorization to pursue 200 MW in additional demand-side management and distributed energy resource programs.[6] Petitioner contemplates submitting them to the Commission on a program-by-program basis, with approval contingent on a reasonable demonstration that the project results in positive benefit for all customers over its term. This demonstration would take into account the costs and revenue impacts of the project and the expected value corresponding to an avoided generic capacity addition, along with other positive benefits that may accrue through load growth, load retention or other relevant considerations associated with the particular project.

8. Petitioner states that the described generating units and PPAs, together with all transmission arrangements, structures, substations, and facilities, environmental control measures, facilities or arrangements for the handling, treatment, transportation, delivery and processing of fuel, and any and all other appliances, appurtenances, facilities, rights, equipment, acquisitions, commitments and accounting authorizations necessary for or incident thereto, are

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[5] These solar/BESS projects and the associated PPAs are addressed in the supporting testimony and exhibits of John B. Kelley.

[6] These additional demand-side management and distributed energy resource programs are addressed in the supporting testimony of John B. Kelley.

necessary, advantageous, efficient and appropriate for the purposes aforesaid and are in the public interest.[7]

9. Petitioner states that the costs associated with the portfolio of resources described in this Petition will be recovered through cost recovery mechanisms established by the Commission (specifically, Rate CNP–Adjustment for Commercial Operation of Certificated New Plant, Rate ECR–Energy Cost Recovery Rate, and Rate RSE–Rate Stabilization and Equalization Factor), together with such accounting authorizations, directions and clarifications from the Commission as needed in the circumstances.[8]

WHEREFORE, Petitioner requests that this Commission, after a public hearing of all parties interested at a time and place fixed by the Commission, grant to the Company a certificate of convenience and necessity pursuant to the provisions of Alabama Code § 37-4-28 (1975) and Parts A and B of Rate CNP–Adjustment for Commercial Operation of Certificated New Plant, approving and authorizing the portfolio of resources set forth in this Petition, together with all transmission arrangements, structures, substations, and facilities, environmental control measures, facilities or arrangements for the handling, treatment, transportation, delivery and processing of fuel, and any and all other appliances, appurtenances, facilities, rights, equipment, acquisitions, commitments and accounting authorizations necessary for or incident, and that the Commission make and enter such further orders as may be necessary or appropriate.

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[7] The cost-effectiveness of the proposed portfolio of generating resources and the manner by which that determination was made are addressed in the supporting testimony and exhibits of John B. Kelley and M. Brandon Looney.

[8] The timing and manner by which costs associated with the proposed generating resources would be recovered, along with associated accounting authorizations, are explained in detail in the supporting testimony of Christine M. Baker. The regulatory process associated with the demand-side management and distributed energy resource programs is addressed in the testimony of John B. Kelley.

This 6th day of September, 2019.

ALABAMA POWER COMPANY

By: ______________________
Executive Vice President

BALCH & BINGHAM LLP
Dan H. McCrary
Scott B. Grover
1710 North Sixth Avenue
Birmingham, AL 35203
(205) 251-8100

Attorneys for Petitioner

2019 Integrated resource plan

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Table 6.1 – 2019 Supply-Side Resource Table (2018$)

Description		Resource Characteristics				Costs			Operating Characteristics				Environmental			
Fuel	Resource	Elevation (AFSL)	Net Capacity (MW)	Commercial Operation Year	Design Life (yrs)	Base Capital ($/KW)	Var O&M ($/MWh)	Fixed O&M ($/KW-yr)	Average Full Load Heat Rate (HHV Btu/KWh)/Efficiency	EFOR (%)	POR (%)	Water Consumed (Gal/MWh)	SO2 (lbs/MMBtu)	NOx (lbs/MMBtu)	Hg (lbs/TBTu)	CO2 (lbs/MMBtu)
Natural Gas	SCCT Aero x3, ISO	0	142	2023	30	1,570	7.54	27.14	9279	2.6	3.9	58	0.0006	0.009	0.255	117
Natural Gas	Intercooled SCCT Aero x2, ISO	0	231	2023	30	1,092	5.05	18.78	8725	2.9	3.9	80	0.0006	0.009	0.255	117
Natural Gas	SCCT Frame "F" x1, ISO	0	233	2023	35	704	5.50	13.28	9811	2.7	3.9	20	0.0006	0.009	0.255	117
Natural Gas	IC Recips x 6, ISO	0	111	2023	35	1,810	7.45	29.82	8272	2.5	5.0	5	0.0006	0.0288	0.255	117
Natural Gas	CCCT Dry "G/H", 1x1, ISO	0	419	2024	40	1,469	1.76	20.52	6847	2.5	3.8	11	0.0006	0.0072	0.255	117
Natural Gas	CCCT Dry "G/H", DF, 1x1, ISO	0	51	2024	40	478	0.15	5.39	6847	0.8	3.8	11	0.0006	0.0072	0.255	117
Natural Gas	CCCT Dry "G/H", 2x1, ISO	0	840	2025	40	1,060	1.67	13.79	6861	2.5	3.8	11	0.0006	0.0072	0.255	117
Natural Gas	CCCT Dry "G/H", DF, 2x1, ISO	0	102	2025	40	365	0.16	4.44	6861	0.8	3.8	11	0.0006	0.0072	0.255	117
Natural Gas	CCCT Dry "J/HA.02", 1x1, ISO	0	539	2024	40	1,218	1.70	17.66	6787	2.5	3.8	0	0.0006	0.0072	0.255	117
Natural Gas	CCCT Dry "J/HA.02", DF, 1x1, ISO	0	63	2024	40	407	0.16	4.86	6787	0.8	3.8	0	0.0006	0.0072	0.255	117
Natural Gas	CCCT Dry, "J/HA.02" 2X1, ISO	0	1,083	2025	40	881	1.62	12.00	6787	2.5	3.8	0	0.0006	0.0072	0.255	117
Natural Gas	CCCT Dry "J/HA.02", DF, 2X1, ISO	0	126	2025	40	316	0.16	4.05	6787	0.8	3.8	0	0.0006	0.0072	0.255	117
Natural Gas	SCCT Aero x3	1,500	138	2023	30	1,612	7.76	27.96	9228	2.6	3.9	58	0.0006	0.009	0.255	117
Natural Gas	Intercooled SCCT Aero x2	1,500	221	2023	30	1,143	5.35	19.88	8689	2.9	3.9	80	0.0006	0.009	0.255	117
Natural Gas	SCCT Frame "F" x1	1,500	221	2023	35	741	5.81	14.02	9792	2.7	3.9	20	0.0006	0.009	0.255	117
Natural Gas	IC Recips x 6	1,500	111	2023	35	1,810	7.45	29.82	8272	2.5	5.0	5	0.0006	0.0288	0.255	117
Natural Gas	CCCT Dry "G/H", 1x1	1,500	396	2024	40	1,552	1.86	21.68	6788	2.5	3.8	11	0.0006	0.0072	0.255	117
Natural Gas	CCCT Dry "G/H", DF, 1x1	1,500	51	2024	40	478	0.15	5.39	6788	0.8	3.8	11	0.0006	0.0072	0.255	117
Natural Gas	CCCT Dry "G/H", 2x1	1,500	795	2025	40	1,120	1.77	14.57	6800	2.5	3.8	11	0.0006	0.0072	0.255	117
Natural Gas	CCCT Dry "G/H", DF, 2x1	1,500	102	2025	40	365	0.16	4.44	6800	0.8	3.8	11	0.0006	0.0072	0.255	117
Natural Gas	CCCT Dry "J/HA.02", 1x1	1,500	510	2024	40	1,288	1.80	18.67	6732	2.5	3.8	11	0.0006	0.0072	0.255	117
Natural Gas	CCCT Dry "J/HA.02", DF, 1x1	1,500	63	2024	40	407	0.16	4.86	6732	0.8	3.8	11	0.0006	0.0072	0.255	117
Natural Gas	CCCT Dry, "J/HA.02" 2X1	1,500	1,023	2025	40	932	1.71	12.69	6732	2.5	3.8	11	0.0006	0.0072	0.255	117
Natural Gas	CCCT Dry "J/HA.02", DF, 2X1	1,500	126	2025	40	316	0.16	4.05	6732	0.8	3.8	11	0.0006	0.0072	0.255	117
Natural Gas	SCCT Aero x3	3,000	131	2023	30	1,704	8.21	29.58	9232	2.6	3.9	58	0.0006	0.009	0.255	117
Natural Gas	Intercooled SCCT Aero x2	3,000	209	2023	30	1,209	5.67	21.10	8687	2.9	3.9	80	0.0006	0.009	0.255	117
Natural Gas	SCCT Frame "F" x1	3,000	210	2023	35	782	6.13	14.81	9799	2.7	3.9	20	0.0006	0.009	0.255	117
Natural Gas	IC Recips x 6	3,000	111	2023	35	1,810	7.45	29.82	8273	2.5	5.0	5	0.0006	0.0288	0.255	117
Natural Gas	CCCT Dry "G/H", 1x1	3,000	375	2024	40	1,641	1.97	22.92	6762	2.5	3.8	11	0.0006	0.0072	0.255	117
Natural Gas	CCCT Dry "G/H", DF, 1x1	3,000	51	2024	40	478	0.15	5.39	6762	0.8	3.8	11	0.0006	0.0072	0.255	117
Natural Gas	CCCT Dry "G/H", 2x1	3,000	752	2025	40	1,184	1.86	15.39	6775	2.5	3.8	11	0.0006	0.0072	0.255	117
Natural Gas	CCCT Dry "G/H", DF, 2x1	3,000	102	2025	40	365	0.16	4.44	6775	0.8	3.8	11	0.0006	0.0072	0.255	117
Natural Gas	CCCT Dry "J/HA.02", 1x1	3,000	482	2024	40	1,363	1.90	19.73	6690	2.5	3.8	11	0.0006	0.0072	0.255	117
Natural Gas	CCCT Dry "J/HA.02", DF, 1x1	3,000	63	2024	40	407	0.16	4.86	6690	0.8	3.8	11	0.0006	0.0072	0.255	117
Natural Gas	CCCT Dry, "J/HA.02" 2X1	3,000	967	2025	40	986	1.81	13.41	6692	2.5	3.8	11	0.0006	0.0072	0.255	117
Natural Gas	CCCT Dry "J/HA.02", DF, 2X1	3,000	126	2025	40	316	0.16	4.05	6692	0.8	3.8	11	0.0006	0.0072	0.255	117
Natural Gas	SCCT Aero x3	5,050	122	2023	30	1,829	8.85	31.86	9229	2.6	3.9	58	0.0006	0.009	0.255	117
Natural Gas	Intercooled SCCT Aero x2	5,050	194	2023	30	1,305	6.14	22.82	8680	2.9	3.9	80	0.0006	0.009	0.255	117
Natural Gas	SCCT Frame "F" x1	5,050	194	2023	35	843	6.61	15.97	9805	2.7	3.9	20	0.0006	0.009	0.255	117
Natural Gas	IC Recips x 6	5,050	111	2023	35	1,810	7.45	29.82	8280	2.5	5.0	5	0.0006	0.0288	0.255	117
Natural Gas	CCCT Dry "G/H", 1x1	5,050	344	2024	40	1,788	2.12	24.74	6510	2.5	3.8	11	0.0006	0.0072	0.255	117
Natural Gas	CCCT Dry "G/H", DF, 1x1	5,050	51	2024	40	478	0.15	5.39	6510	0.8	3.8	11	0.0006	0.0072	0.255	117
Natural Gas	CCCT Dry "G/H", 2x1	5,050	687	2025	40	1,297	2.01	16.63	6520	2.5	3.8	11	0.0006	0.0072	0.255	117
Natural Gas	CCCT Dry "G/H", DF, 2x1	5,050	102	2025	40	365	0.16	4.44	6520	0.8	3.8	11	0.0006	0.0072	0.255	117
Natural Gas	CCCT Dry "J/HA.02", 1x1	5,050	442	2024	40	1,485	2.05	21.26	6464	2.5	3.8	11	0.0006	0.0072	0.255	117
Natural Gas	CCCT Dry "J/HA.02", DF, 1x1	5,050	63	2024	40	407	0.16	4.86	6464	0.8	3.8	11	0.0006	0.0072	0.255	117
Natural Gas	CCCT Dry, "J/HA.02" 2X1	5,050	884	2025	40	1,079	1.95	14.45	6469	2.5	3.8	11	0.0006	0.0072	0.255	117
Natural Gas	CCCT Dry "J/HA.02", DF, 2X1	5,050	126	2025	40	316	0.16	4.05	6469	0.8	3.8	11	0.0006	0.0072	0.255	117
Natural Gas	SCCT Aero x3	6,500	113	2023	30	1,975	9.60	34.56	9209	2.6	3.9	58	0.0006	0.009	0.255	117
Natural Gas	Intercooled SCCT Aero x2	6,500	181	2023	30	1,394	6.45	24.00	8694	2.9	3.9	80	0.0006	0.009	0.255	117
Natural Gas	SCCT Frame "F" x1	6,500	185	2023	35	887	6.96	16.81	9786	2.7	3.9	20	0.0006	0.009	0.255	117
Natural Gas	IC Recips x 6	6,500	111	2023	35	1,810	7.75	31.04	8320	2.5	5.0	5	0.0006	0.0288	0.255	117
Natural Gas	CCCT Dry "G/H", 1x1	6,500	333	2024	40	1,843	2.25	26.20	6757	2.5	3.8	11	0.0006	0.0072	0.255	117
Natural Gas	CCCT Dry "G/H", DF, 1x1	6,500	51	2024	40	478	0.15	5.39	6757	0.8	3.8	11	0.0006	0.0072	0.255	117
Natural Gas	CCCT Dry "G/H", 2x1	6,500	669	2025	40	1,330	2.13	17.61	6772	2.5	3.8	11	0.0006	0.0072	0.255	117
Natural Gas	CCCT Dry "G/H", DF, 2x1	6,500	102	2025	40	365	0.16	4.44	6772	0.8	3.8	11	0.0006	0.0072	0.255	117
Natural Gas	CCCT Dry "J/HA.02", 1x1	6,500	424	2024	40	1,549	2.15	22.33	6681	2.5	3.8	11	0.0006	0.0072	0.255	117
Natural Gas	CCCT Dry "J/HA.02", DF, 1x1	6,500	63	2024	40	407	0.16	4.86	6681	0.8	3.8	11	0.0006	0.0072	0.255	117
Natural Gas	CCCT Dry, "J/HA.02" 2X1	6,500	851	2025	40	1,120	2.05	15.18	6681	2.5	3.8	11	0.0006	0.0072	0.255	117
Natural Gas	CCCT Dry "J/HA.02", DF, 2X1	6,500	126	2025	40	316	0.16	4.06	6681	0.8	3.8	11	0.0006	0.0072	0.255	117

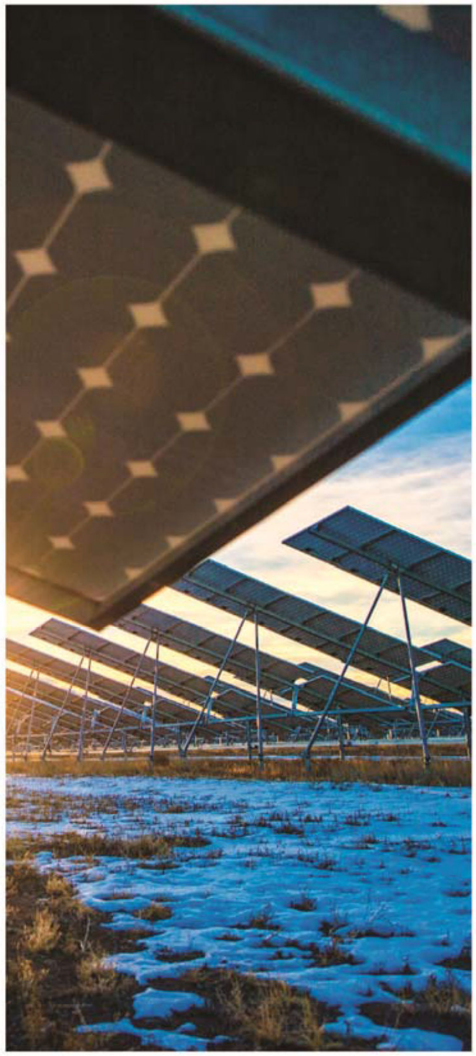
Table 6.1 – 2019 Supply-Side Resource Table (2018$) (Continued)

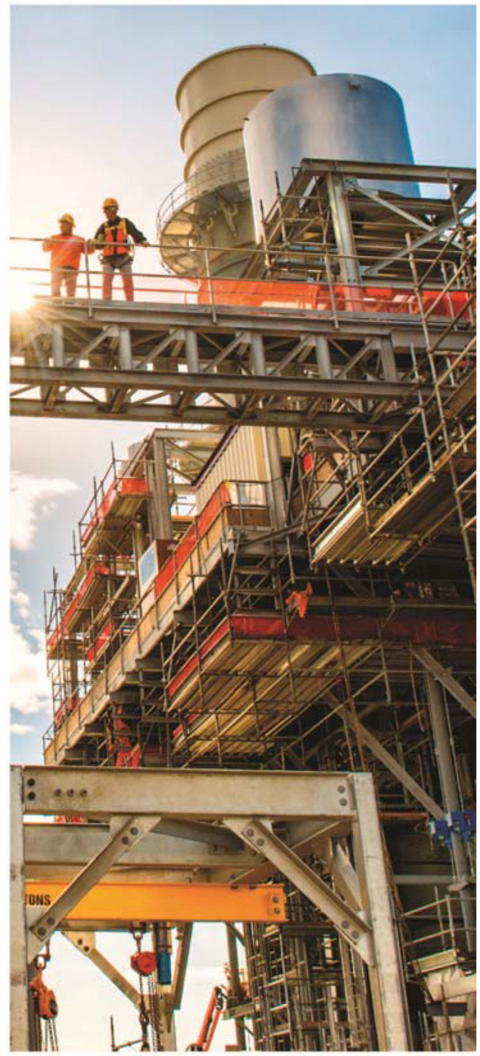
Description		Resource Characteristics				Costs			Operating Characteristics				Environmental			
Fuel	Resource	Elevation (AFSL)	Net Capacity (MW)	Commercial Operation Year	Design Life (yrs)	Base Capital ($/KW)	Var O&M ($/MWh)	Fixed O&M ($/KW-yr)	Average Full Load Heat Rate (HHV Btu/KWh)/Efficiency	EFOR (%)	POR (%)	Water Consumed (Gal/MWh)	SO2 (lbs/MMBtu)	NOx (lbs/MMBtu)	Hg (lbs/TBTu)	CO2 (lbs/MMBtu)
Coal	SCPC with CCS	4,500	526	2036	40	6,462	7.00	72.22	13087	5.0	5.0	1,004	0.009	0.070	0.022	20.5
Coal	IGCC with CCS	4,500	466	2036	40	6,257	11.77	58.20	10823	8.0	7.0	394	0.009	0.050	0.333	20.5
Coal	PC CCS retrofit @ 500 MW	4,500	-139	2033	20	1,419	6.47	77.76	14372	5.0	5.0	1,004	0.005	0.070	1.200	20.5
Coal	SCPC with CCS	6,500	692	2036	40	7,318	7.58	67.09	13242	5.0	5.0	1,004	0.009	0.070	0.022	20.5
Coal	IGCC with CCS	6,500	456	2036	40	7,085	14.11	63.40	11047	8.0	7.0	394	0.009	0.050	0.333	20.5
Coal	PC CCS retrofit @ 500 MW	6,500	-139	2031	20	1,607	7.00	72.22	14372	5.0	5.0	1,004	0.005	0.070	1.200	20.5
Geothermal	Blundell Dual Flash 90% CF	4,500	35	2021	40	5,708	1.16	103.85	n/a	5.0	5.0	10	n/a	n/a	n/a	n/a
Geothermal	Greenfield Binary 90% CF	4,500	43	2023	40	5,973	1.16	103.85	n/a	5.0	5.0	270	n/a	n/a	n/a	n/a
Geothermal	Generic Geothermal PPA 90% CF	4,500	30	2021	20	0	77.34	0.00	n/a	5.0	5.0	270	n/a	n/a	n/a	n/a
Wind	3.6 MW Wind turbine 37.1% CF WA, 2020	4,500	200	2020	30	1,354	0.00	27.99	n/a	Included with CF	0	n/a	n/a	n/a	n/a	n/a
Wind	3.6 MW Wind turbine 37.1% CF OR, 2020	1,500	200	2020	30	1,334	0.00	27.99	n/a	Included with CF	0	n/a	n/a	n/a	n/a	n/a
Wind	3.6 MW Wind turbine 37.1% CF ID, 2020	4,500	200	2020	30	1,358	0.00	27.99	n/a	Included with CF	0	n/a	n/a	n/a	n/a	n/a
Wind	3.6 MW Wind turbine 29.5% CF UT, 2020	6,500	200	2020	30	1,301	0.00	27.99	n/a	Included with CF	0	n/a	n/a	n/a	n/a	n/a
Wind	3.6 MW Wind turbine 43.6% CF WY, 2020	1,500	240	2020	30	1,301	0.65	27.99	n/a	Included with CF	0	n/a	n/a	n/a	n/a	n/a
Wind + Storag	Wind + Stor, Pocatello, ID, 200 MW+ 50 MW | 100 MWh	4,500	200	2023	30	1,738	0.00	29.18	1	Included with CF	0	n/a	n/a	n/a	n/a	n/a
Wind + Storag	Wind + Stor, Arlington, OR, 200 MW+ 50 MW | 100 MWh	1,500	200	2023	30	1,765	0.00	29.18	1	Included with CF	0	n/a	n/a	n/a	n/a	n/a
Wind + Storag	Wind + Stor, Monticello, UT, 200 MW+ 50 MW | 100 MWh	4,500	200	2023	30	1,735	0.00	29.18	1	Included with CF	0	n/a	n/a	n/a	n/a	n/a
Wind + Storag	Wind + Stor, Medicine Bow, WY, 200 MW+ 50 MW | 100 MWh	6,500	200	2023	30	1,730	0.65	29.18	1	Included with CF	0	n/a	n/a	n/a	n/a	n/a
Wind + Storag	Wind + Stor, Goldendale, WA, 200 MW+ 50 MW | 100 MWh	1,500	200	2023	30	1,772	0.00	29.18	1	Included with CF	0	n/a	n/a	n/a	n/a	n/a
Wind + Storag	Wind + Stor, Pocatello, ID, 200 MW+ 50 MW | 200 MWh	4,500	200	2023	30	1,880	0.00	29.88	1	Included with CF	0	n/a	n/a	n/a	n/a	n/a
Wind + Storag	Wind + Stor, Arlington, OR, 200 MW+ 50 MW | 200 MWh	1,500	200	2023	30	1,917	0.00	29.88	1	Included with CF	0	n/a	n/a	n/a	n/a	n/a
Wind + Storag	Wind + Stor, Monticello, UT, 200 MW+ 50 MW | 200 MWh	4,500	200	2023	30	1,877	0.00	29.88	1	Included with CF	0	n/a	n/a	n/a	n/a	n/a
Wind + Storag	Wind + Stor, Medicine Bow, WY, 200 MW+ 50 MW | 200 MWh	6,500	200	2023	30	1,872	0.65	29.88	1	Included with CF	0	n/a	n/a	n/a	n/a	n/a
Wind + Storag	Wind + Stor, Goldendale, WA, 200 MW+ 50 MW | 200 MWh	1,500	200	2023	30	1,924	0.00	29.88	1	Included with CF	0	n/a	n/a	n/a	n/a	n/a
Wind + Storag	Wind + Stor, Pocatello, ID, 200 MW+ 50 MW | 400 MWh	4,500	200	2023	30	2,158	0.00	31.03	1	Included with CF	0	n/a	n/a	n/a	n/a	n/a
Wind + Storag	Wind + Stor, Arlington, OR, 200 MW+ 50 MW | 400 MWh	1,500	200	2023	30	2,214	0.00	31.03	1	Included with CF	0	n/a	n/a	n/a	n/a	n/a
Wind + Storag	Wind + Stor, Monticello, UT, 200 MW+ 50 MW | 400 MWh	4,500	200	2023	30	2,155	0.00	31.03	1	Included with CF	0	n/a	n/a	n/a	n/a	n/a
Wind + Storag	Wind + Stor, Medicine Bow, WY, 200 MW+ 50 MW | 400 MWh	6,500	200	2023	30	2,150	0.65	31.03	1	Included with CF	0	n/a	n/a	n/a	n/a	n/a
Wind + Storag	Wind + Stor, Goldendale, WA, 200 MW+ 50 MW | 400 MWh	1,500	200	2023	30	2,221	0.00	31.03	1	Included with CF	0	n/a	n/a	n/a	n/a	n/a
Solar	PV Idaho Falls, ID, 50 MW, 28.1% CF	4,700	50	2021	25	1,366	0.00	21.72	n/a	Included with CF	0	n/a	n/a	n/a	n/a	n/a
Solar	PV Idaho Falls, ID, 200 MW, 2021, 28.1% CF	4,700	200	2021	25	1,271	0.00	21.72	n/a	Included with CF	0	n/a	n/a	n/a	n/a	n/a
Solar	PV Lakeview, OR, 50 MW, 2021, 29.7% CF	4,800	50	2021	25	1,424	0.00	22.35	n/a	Included with CF	0	n/a	n/a	n/a	n/a	n/a
Solar	PV Lakeview, OR, 200 MW, 2021, 29.7% CF	4,800	200	2021	25	1,329	0.00	22.35	n/a	Included with CF	0	n/a	n/a	n/a	n/a	n/a
Solar	PV Milford, UT, 50 MW, 2021, 32.5% CF	5,000	50	2021	25	1,363	0.00	22.32	n/a	Included with CF	0	n/a	n/a	n/a	n/a	n/a
Solar	PV Milford, UT, 200 MW, 2021, 32.5% CF	5,000	200	2021	25	1,268	0.00	22.32	n/a	Included with CF	0	n/a	n/a	n/a	n/a	n/a
Solar	PV Utah North, 200 MW, 2021, 30.1% CF	5,000	200	2021	25	1,266	0.00	21.13	n/a	Included with CF	0	n/a	n/a	n/a	n/a	n/a
Solar	PV Rock Springs, WY, 50 MW, 2021, 30.1% CF	6,400	50	2021	25	1,360	0.00	21.13	n/a	Included with CF	0	n/a	n/a	n/a	n/a	n/a
Solar	PV Rock Springs, WY, 200 MW, 2021, 30.1% CF	6,400	200	2021	25	1,266	0.00	21.13	n/a	Included with CF	0	n/a	n/a	n/a	n/a	n/a
Solar	PV Yakima, WA, 50 MW, 2021, 26% CF	1,000	50	2021	25	1,422	0.00	22.35	n/a	Included with CF	0	n/a	n/a	n/a	n/a	n/a
Solar	PV Yakima, WA, 200 MW, 2021, 26% CF	1,000	200	2021	25	1,327	0.00	22.35	n/a	Included with CF	0	n/a	n/a	n/a	n/a	n/a
Solar + Storag	PV + Stor, Idaho Falls, ID, 50 MW + 10 MW X 20 MWh	4,700	50	2021	25	1,628	0.00	23.48	1	Included with CF	0	n/a	n/a	n/a	n/a	n/a
Solar + Storag	PV + Stor, Idaho Falls, ID, 200 MW + 50 MW X 100 MWh	4,700	200	2021	25	1,470	0.00	22.91	1	Included with CF	0	n/a	n/a	n/a	n/a	n/a
Solar + Storag	PV + Stor,, Idaho Falls, ID, 50 MW + 10 MW X 40 MWh	4,700	50	2021	25	1,756	0.00	25.03	1	Included with CF	0	n/a	n/a	n/a	n/a	n/a
Solar + Storag	PV + Stor, Idaho Falls, ID, 200 MW + 50 MW X 200 MWh	4,700	200	2021	25	1,614	0.00	24.24	1	Included with CF	0	n/a	n/a	n/a	n/a	n/a
Solar + Storag	PV + Stor, Idaho Falls, ID, 50 MW + 10 MW X 80 MWh	4,700	50	2021	25	1,992	0.00	26.46	1	Included with CF	0	n/a	n/a	n/a	n/a	n/a
Solar + Storag	PV + Stor, Idaho Falls, ID, 200 MW + 50 MW X 400 MWh	4,700	200	2021	25	1,897	0.00	25.36	1	Included with CF	0	n/a	n/a	n/a	n/a	n/a
Solar + Storag	PV + Stor, Lakeview, OR, 50 MW + 10 MW X 20 MWh	4,800	50	2021	25	1,706	0.00	23.48	1	Included with CF	0	n/a	n/a	n/a	n/a	n/a
Solar + Storag	PV + Stor, Lakeview, OR, 200 MW + 50 MW X 100 MWh	4,800	200	2021	25	1,543	0.00	22.91	1	Included with CF	0	n/a	n/a	n/a	n/a	n/a
Solar + Storag	PV + Stor, Lakeview, OR, 50 MW + 10 MW X 40 MWh	4,800	50	2021	25	1,844	0.00	25.03	1	Included with CF	0	n/a	n/a	n/a	n/a	n/a
Solar + Storag	PV + Stor, Lakeview, OR, 200 MW + 50 MW X 200 MWh	4,800	200	2021	25	1,699	0.00	24.24	1	Included with CF	0	n/a	n/a	n/a	n/a	n/a
Solar + Storag	PV + Stor, Lakeview, OR, 50 MW + 10 MW X 80 MWh	4,800	50	2021	25	2,098	0.00	26.46	1	Included with CF	0	n/a	n/a	n/a	n/a	n/a
Solar + Storag	PV + Stor,, Lakeview, OR, 200 MW + 50 MW X 400 MWh	4,800	200	2021	25	2,004	0.00	25.36	1	Included with CF	0	n/a	n/a	n/a	n/a	n/a
Solar + Storag	PV + Stor,, Milford, UT, 50 MW + 10 MW X 20 MWh	5,000	50	2021	25	1,626	0.00	23.48	1	Included with CF	0	n/a	n/a	n/a	n/a	n/a
Solar + Storag	PV + Stor,, Milford, UT, 200 MW + 50 MW X 100 MWh	5,000	200	2021	25	1,467	0.00	22.91	1	Included with CF	0	n/a	n/a	n/a	n/a	n/a
Solar + Storag	PV + Stor,, Milford, UT 50 MW + 10 MW X 40 MWh	5,000	50	2021	25	1,754	0.00	25.03	1	Included with CF	0	n/a	n/a	n/a	n/a	n/a
Solar + Storag	PV + Stor,, Milford, UT, 200 MW + 50 MW X 200 MWh	5,000	200	2021	25	1,612	0.00	24.24	1	Included with CF	0	n/a	n/a	n/a	n/a	n/a
Solar + Storag	PV + Stor,, Milford, UT, 50 MW + 10 MW X 80 MWh	5,000	50	2021	25	1,990	0.00	26.46	1	Included with CF	0	n/a	n/a	n/a	n/a	n/a
Solar + Storag	PV + Stor,, Milford, UT, 200 MW + 50 MW X 400 MWh	5,000	200	2021	25	1,895	0.00	25.36	1	Included with CF	0	n/a	n/a	n/a	n/a	n/a
Solar + Storag	PV + Stor, Utah North, 200 MW + 50 MW X 200 MWh	5,000	200	2021	25	1,609	0.00	24.24	1	Included with CF	0	n/a	n/a	n/a	n/a	n/a
Solar + Storag	PV + Stor,, Rock Springs, WY, 50 MW + 10 MW X 20 MWh	6,400	50	2021	25	1,623	0.00	23.48	1	Included with CF	0	n/a	n/a	n/a	n/a	n/a
Solar + Storag	PV + Stor,, Rock Springs, WY, 200 MW + 50 MW X 100 MWh	6,400	200	2021	25	1,464	0.00	22.91	1	Included with CF	0	n/a	n/a	n/a	n/a	n/a
Solar + Storag	PV + Stor,, Rock Springs, WY, 50 MW + 10 MW X 40 MWh	6,400	50	2021	25	1,751	0.00	25.03	1	Included with CF	0	n/a	n/a	n/a	n/a	n/a
Solar + Storag	PV + Stor,, Rock Springs, WY, 200 MW + 50 MW X 200 MWh	6,400	200	2021	25	1,609	0.00	24.24	1	Included with CF	0	n/a	n/a	n/a	n/a	n/a
Solar + Storag	PV + Stor,, Rock Springs, WY, 50 MW + 10 MW X 80 MWh	6,400	50	2021	25	1,987	0.00	26.46	1	Included with CF	0	n/a	n/a	n/a	n/a	n/a
Solar + Storag	PV + Stor,, Rock Springs, WY, 200 MW + 50 MW X 400 MWh	6,400	200	2021	25	1,892	0.00	25.36	1	Included with CF	0	n/a	n/a	n/a	n/a	n/a
Solar + Storag	PV + Stor,, Yakima, WA, 50 MW + 10 MW X 20 MWh	1,000	50	2021	25	1,704	0.00	23.48	1	Included with CF	0	n/a	n/a	n/a	n/a	n/a
Solar + Storag	PV + Stor, Yakima, WA, 200 MW + 50 MW X 100 MWh	1,000	200	2021	25	1,541	0.00	22.91	1	Included with CF	0	n/a	n/a	n/a	n/a	n/a
Solar + Storag	PV + Stor, Yakima, WA, 50 MW + 10 MW X 40 MWh	1,000	50	2021	25	1,842	0.00	25.03	1	Included with CF	0	n/a	n/a	n/a	n/a	n/a
Solar + Storag	PV + Stor, Yakima, WA, 200 MW + 50 MW X 200 MWh	1,000	200	2021	25	1,697	0.00	24.24	1	Included with CF	0	n/a	n/a	n/a	n/a	n/a
Solar + Storag	PV + Stor, Yakima, WA, 50 MW + 10 MW X 80 MWh	1,000	50	2021	25	2,097	0.00	26.46	1	Included with CF	0	n/a	n/a	n/a	n/a	n/a
Solar + Storag	PV + Stor, Yakima, WA, 200 MW + 50 MW X 400 MWh	1,000	200	2021	25	2,002	0.00	25.36	1	Included with CF	0	n/a	n/a	n/a	n/a	n/a

Table 6.1 – 2019 Supply-Side Resource Table (2018$) (Continued)

Description		Resource Characteristics				Costs			Operating Characteristics				Environmental			
Fuel	Resource	Elevation (AFSL)	Net Capacity (MW)	Commercial Operation Year	Design Life (yrs)	Base Capital ($/KW)	Var O&M ($/MWh)	Fixed O&M ($/KW-yr)	Average Full Load Heat Rate (HHV Btu/KWh)/Efficiency	EFOR (%)	POR (%)	Water Consumed (Gal/MWh)	SO2 (lbs/MMBtu)	NOx (lbs/MMBtu)	Hg (lbs/TBTu)	CO2 (lbs/MMBtu)
Storage	Oregon PS, 400 MW X 3,800 MWh	4,457	400	2025	60	3,095	0.00	16.76	79%	3	7	0	0	0	0	0
Storage	Oregon PS joint ownership, 100 MW X 950 MWh	4,457	100	2025	60	3,099	0.00	16.76	79%	3	7	0	0	0	0	0
Storage	Washington PS, 1,200 MW X 16,800 MWh	500	1,200	2029	60	2,719	0.00	12.50	79%	3	7	0	0	0	0	0
Storage	Wyoming PS, 700 MW X 7,000 MWh	580	700	2027	60	3,255	0.00	17.00	79%	3	7	0	0	0	0	0
Storage	Wyoming PS, 400 MW X 3,400 MWh	6,000	400	2028	60	2,348	0.00	17.00	79%	3	7	0	0	0	0	0
Storage	Utah PS, 300 MW X 1,800 MWh	6,359	300	2025	60	2,991	0.00	17.00	79%	3	7	0	0	0	0	0
Storage	Idaho PS, 360 MW X 2,880 MWh	5,000	360	2031	60	2,680	0.00	17.00	79%	3	7	0	0	0	0	0
Storage	Idaho PS, 360 MW X 2,880 MWh	5,000	360	2031	60	2,680	0.00	17.00	79%	3	7	0	0	0	0	0
Storage	CAES, 320 MW X 15,360 MWh	4,600	320	2022	30	1,625	0.00	7.01	4230 / 55%	1	3	0	0	0	0	117
Storage	Li-Ion 1 MW X 250 kWh	0	1	2020	15	1,473	11.42	8.29	88%	1	3	0	0	0	0	0
Storage	Li-Ion 1 MW X 2 MWh	0	1	2020	15	2,615	15.70	23.56	88%	1	3	0	0	0	0	0
Storage	Li-Ion 1 MW X 4 MWh	0	1	2020	15	3,412	14.98	35.23	88%	1	3	0	0	0	0	0
Storage	Li-Ion 1 MW X 8 MWh	0	1	2020	15	5,455	14.98	52.09	88%	1	3	0	0	0	0	0
Storage	Li-Ion 15 MW X 60 MWh	0	15	2020	15	1,766	15.07	11.50	88%	1	3	0	0	0	0	0
Storage	Flow 1 MW X 6 MWh	0	1	2021	15	3,996	0.00	32.00	65%	2	3	0	0	0	0	0
Nuclear	Advanced Fission	5,000	2,234	2030	40	6,765	11.75	101.62	10,710	7.7	7.3	96	0	0	0	0
Nuclear	Small Modular Reactor x 12	5,000	570	2028	40	6,028	15.50	173.35	10,710	7.7	7.3	65	0	0	0	0

Xcel Energy®
RESPONSIBLE BY NATURE®





Public Service Company of Colorado

2016 Electric Resource Plan
Volume 2

(CPUC Proceeding No. 16A-0396E)
May 27, 2016

Table 2.7-10 Generic Dispatchable Resource Cost and Performance

Dispatchable Resources 1,2	2x1 CC [6,7]	1x1 CC [6,8]	Large CT [9]	LMS CT [10]	Aeroder. CT [11]
Nameplate Capacity (MW)	700	329	205	94	40
Summer Duct Firing Capacity (MW)	101	44	NA	NA	NA
Summer Peak Capacity (MW)	658	289	192	80	31
Fuel Source [3]	Nat Gas	Nat Gas	Nat Gas	Nat Gas	Nat Gas
Cooling	Dry	Dry	Dry	Dry	Dry
Capital Cost ($/kW) [4]	$843	$1,145	$610	$1,375	$1,988
Book Life	40	40	40	40	40
Fixed O&M Cost ($000/yr) [4]	$5,650	$3,421	$464	$640	$414
Variable O&M Cost ($/MWh)	$0.39	$0.44	$1.28	$1.17	$2.08
Ongoing Capital Expenditures	$3,509	$1,892	$1,692	$192	$110
Heat Rate with Duct Firing	7,839	NA	NA	NA	NA
Heat Rate 100 % Loading	6,925	8,492	9,955	9,146	9,635
Heat Rate ~75 % Loading	7,011	7,004	11,079	10,145	11,456
Heat Rate ~50 % Loading	7,149	7,391	14,661	11,761	14,904
Heat Rate ~30 % Loading	8,139	7,732	NA	16,092	23,291
Forced Outage Rate	3%	3%	3%	2%	3%
Maintenance (wks/yr)	3	3	2	2	2
Typical Capacity Factor	37%	37%	9%	10%	10%
CO2 Emissions (lbs/MMBtu)	118	118	118	118	118

Notes:

(1) All Costs in year 2015 dollars

(2) Thermal unit cost and performance characteristics are from Xcel Energy Services and other sources such as CERA, EPRI, and EIA

(3) For all units, a firm fuel charge of $6.16/kW-yr (levelized) has been applied

(4) Estimates of generic capital and fixed O&M costs are based on the midpoint between the costs of a greenfield EPC facility and those of a brownfield facility. Brownfield costs are estimated by removing certain cost items from the greenfield estimate but costs for an actual brownfield facility are very site specific. To estimate the midpoint costs for combined cycle units, greenfield capital and fixed O&M costs have beem reduced by 7.5% and 20% respectively from greenfield costs. To estimate the midpoint costs for combustion turbine units, greenfield capital and fixed O&M costs have been reduced by 12.5% and 20% respectively.

(5) For combined cycle units, modeled heat rates are the average of winter and summer values. For combustion turbine units, modeled heat rates represent the summer values.

(6) For all combined cycle units, a levelized $25/kW-yr charge has been applied to estimate transmission interconnection costs

(7) Based on Siemens 5000F 2x1 CC

(8) Based on GE 7FA 1x1 CC

(9) Based on Siemens 5000F SC

(10) Based on GE LMS 100

(11) Based on GE LMS 6000

Testimony Calculations

	In Service	Retirements	Rate Change	Total
Distribution	$ 96.8	$ (11.5)	$ 4.6	$ 89.9
Nuclear	$ 17.6	$ (1.8)	$ -	$ 15.9
Steam	$ 16.0	$ (49.3)	$ -	$ (33.3)
Blue Water Energy Center	$ 18.9	$ -	$ -	$ 18.9
Other Generation Plant	$ 2.7	$ (0.5)	$ -	$ 2.2
Hydraulic	$ 3.4	$ (0.5)	$ (8.3)	$ (5.4)
General Plant	$ 49.9	$ (19.2)	$ 0.0	$ 30.7
Other	$ 0.2	$ (0.1)	$ 0.0	$ 0.1
	$ 205.6	**$ (82.9)**	**$ (3.7)**	**$ 118.9**
Intangible Plant				$ 17.3
Amortization of DR Regulatory Asset				$ 1.0
Amortization of Capitalized OPEB				$ (2.4)
AFUDC Reg Asset and Capitalized Pension				$ (0.7)
Total Change in Depreciation and Amortization from Historical				**$ 134.2**

Check $ 0.01

	Historical Plant Balance 12/31/2020	Bridge Plant Balance 12/31/2021	Test Plant Balance 8/31/2023	Change	Historical Depr Exp 12/31/2020	Projected Depr Exp 8/31/2023	Change
Production Plant, Steam	7,690,866	7,876,029	6,850,545	(840,320)	237,910	204,613	(33,297)
Production Plant, Nuclear	1,430,195	1,537,588	1,723,337	293,142	56,394	72,252	15,858
Production Plant, Hydraulic	518,958	534,358	638,949	119,991	22,291	16,857	(5,434)
Production Plant, Other	684,356	712,636	1,803,108	1,118,753	13,572	34,664	21,093
Production Plant, Solar	-	-	-	-	-	-	-
Production Plant, Other (Acquisitions)	-	-	-	-	-	-	-
Production Plant, MERC	96,143	98,594	102,320	6,177	3,866	4,102	235
Transmission Plant	81,889	79,670	75,601	(6,288)	1,875	1,760	(115)
Distribution Plant	9,370,007	10,187,985	11,750,077	2,380,070	372,253	461,482	89,228
Distribution Plant, AMI	418,548	418,548	418,548	-	20,431	21,095	664
General Plant, Amortizable	519,003	504,989	459,517	(59,486)	45,475	39,115	(6,360)
General Plant, Depreciable	702,197	822,613	962,542	260,345	57,003	69,100	12,098
General Plant, Computer Equip 5 yr	60,157	108,243	193,847	133,690	9,225	34,171	24,945
Other Plant, Composite	-	-	-	-	-	-	-
Subtotal Depreciable Plant	21,572,318	22,881,253	24,978,392	3,406,074	840,294	959,209	118,916
Intangible Plant, 3 year	29,337	23,358	3,022	(26,315)	6,268	3,670	(2,597)
Intangible Plant, 4 year	296	296	96	(201)	532	43	(489)
Intangible Plant, 5 year	391,283	463,345	536,011	144,729	71,854	103,672	31,818
Intangible Plant, 7 year	-	-	-	-	-	-	-
Intangible Plant, 15 year	325,572	325,572	200,746	(124,826)	24,395	12,994	(11,401)
Amort. of Utility Plant Acq. Adjustment (406)					5,791	5,791	(0)
AFUDC Reg Asset Amort (407.3)					148	-	(148)
Amort of CTA (407.3)					-	-	-
TRM PLD Surcharge (407.3)					-	-	-
Amort of COLA (407.3)					4,893	4,893	0
Amort of Pension Reg Asset (407.3)					814	268	(546)
Other (407.3)					-	-	-
DECo FERMI Trust Fund Credits (407.4)					-	-	-
Transitional Reconciliation Mechanism (407.4)					-	-	-
Amort of OPEB Reg Liab (407.4)					(1,233)	(3,629)	(2,396)
Accretion Expense (411.1)					-	-	-
					953,755	1,086,912	133,157

Depreciation Variance Analysis ($000)

	SUMMARY					
	Volume Var. Prior Year	Volume Var. Additions	Volume Var. Retirements	Rate Change	Unexplained (plug)	Change per A-13 C6 p. 2
Intangible Plant, 3 year	3,511	-	(6,109)		0	(2,597)
Intangible Plant, 4 year	(458)	-	(31)		-	(489)
Intangible Plant, 5 year	6,403	44,212	(18,796)		0	31,818
Intangible Plant, 7 year	-	-	-		-	-
Intangible Plant, 15 year	(2,690)	1,681	(10,392)		-	(11,401)
Production Plant, Steam	(5,924)	16,046	(43,419)	-	(0)	(33,297)
Production Plant, Nuclear	4,570	13,038	(1,751)	-	(0)	15,858
Production Plant, Hydraulic	(235)	3,384	(261)	(8,323)	(0)	(5,434)
Production Plant, Other	6	21,538	(450)	-	-	21,093
Production Plant, Solar	-	-	-	-	-	
Production Plant, Other (Acquisitions)	-	-	-	-	-	
Production Plant, MERC	27	208	-	-	(0)	235
Transmission Plant	4	-	(119)	0	(0)	(115)
Distribution Plant	6,701	89,445	(11,490)	4,572	-	89,228
Distribution Plant, AMI	664	-	-	-	-	664
General Plant, Amortizable	(2,757)	-	(3,602)	-	0	(6,360)
General Plant, Depreciable	(3,772)	19,465	(3,602)	7	0	12,098
General Plant, Computer Equip 5 yr	2,806	27,644	(5,504)	-	-	24,945
Other Plant, Composite	-	-	-	-	-	-
Total Plant in Service	8,857	236,661	(105,527)	(3,744)	(0)	136,247
Amortization of COL (405)						0
Amort. of Utility Plant Acq. Adj. (406)						(0)
AFUDC-Reg Asset Amort (407.3)						(148)
Amortization of Capitalized Pension (407.3)						(546)
Amortization of 2019 Demand Response (407.3)						1,003
Amortization of Capitalized OPEB (407.4)						(2,396)
						134,160

	Unitization 2021	Unitization Jan 22 - Aug 22	Unitization Sep 22 - Aug 23	Unitization Total	Retirements 2021	Retirements Jan 22 - Aug 22	Retirements Sep 22 - Aug 23	Retirements Total
Production Plant, Steam	252,494	178,645	201,661	632,799	(67,330)	(1,338,459)	(67,330)	(1,473,119)
Production Plant, Nuclear	124,996	143,725	74,297	343,017	(17,603)	(14,669)	(17,603)	(49,876)
Production Plant, Hydraulic	19,621	104,211	8,119	131,951	(4,221)	(3,517)	(4,221)	(11,959)
Production Plant, Other	38,010	986,868	121,442	1,146,320	(9,730)	(8,108)	(9,730)	(27,567)
Production Plant, Solar	-	-	-	-	-	-	-	-
Production Plant, Other (Acquisitions	-	-	-	-	-	-	-	-
Production Plant, MERC	2,452	1,629	2,097	6,177	-	-	-	-
Transmission Plant	-	-	-	-	(2,219)	(1,849)	(2,219)	(6,288)
Distribution Plant	938,281	711,304	1,071,341	2,720,926	(120,302)	(100,252)	(120,302)	(340,856)
Distribution Plant, AMI	-	-	-	-	-	-	-	-
General Plant, Amortizable	-	-	-	-	(14,014)	(14,038)	(31,434)	(59,486)
General Plant, Depreciable	140,778	54,654	122,606	318,037	(20,362)	(16,968)	(20,362)	(57,693)
General Plant, Computer Equip 5 yr	60,175	47,025	62,036	169,236	(12,089)	(7,410)	(16,047)	(35,546)
Other Plant, Composite	-	-	-	-	-	-	-	-
Intangible Plant, 3 year	-	-	-	-	(5,978)	(4,358)	(15,979)	(26,315)
Intangible Plant, 4 year	-	-	-	-	-	(46)	(155)	(201)
Intangible Plant, 5 year	91,937	76,677	104,892	273,506	(19,875)	(39,311)	(69,592)	(128,778)
Intangible Plant, 7 year	-	-	-	-	-	-	-	-
Intangible Plant, 15 year	-	-	50,444	50,444	-	(136,500)	(38,771)	(175,270)

BWEC	951,800
Other	35,068
	986,868

	Estimated Historical Avg	Change in Vol Historical
Production Plant, Steam	7,887,243	(196,378)
Production Plant, Nuclear	1,322,980	107,216
Production Plant, Hydraulic	524,485	(5,528)
Production Plant, Other	684,078	277
Production Plant, Solar	-	-
Production Plant, Other (Acquisitions)	-	-
Production Plant, MERC	95,465	678
Transmission Plant	81,713	176
Distribution Plant	9,204,312	165,695
Distribution Plant, AMI	405,372	13,176
General Plant, Amortizable	552,501	(33,499)
General Plant, Depreciable	751,953	(49,756)
General Plant, Computer Equip 5 yr	46,127	14,030
Other Plant, Composite	-	-
Intangible Plant, 3 year	18,803	10,534
Intangible Plant, 4 year	2,127	(1,831)
Intangible Plant, 5 year	359,269	32,014
Intangible Plant, 7 year	-	-
Intangible Plant, 15 year	365,926	(40,354)

	Depreciation Rates		
	Old Rates	New Rates	Var
Production Plant, Steam	3.02%	3.02%	0.00%
Production Plant, Nuclear	4.26%	4.26%	0.00%
Production Plant, Hydraulic	4.25%	2.65%	-1.60%
Production Plant, Other	1.98%	1.98%	0.00%
Production Plant, Solar	2.52%	2.52%	0.00%
Production Plant, Other (Acquisitions)	0.00%	0.00%	0.00%
Production Plant, MERC	4.05%	4.05%	0.00%
Transmission Plant	2.29%	2.29%	0.00%
Distribution Plant	4.04%	4.09%	0.05%
Distribution Plant, AMI	5.04%	5.04%	0.00%
General Plant, Amortizable	8.23%	8.23%	0.00%
General Plant, Depreciable	7.58%	7.58%	0.00%
General Plant, Computer Equip 5 yr	20.00%	20.00%	0.00%
Other Plant, Composite	4.24%	4.24%	0.00%
Subtotal Depreciable Plant			
Intangible Plant, 3 year	33.33%	33.33%	0.00%
Intangible Plant, 4 year	25.00%	25.00%	0.00%
Intangible Plant, 5 year	20.00%	20.00%	0.00%
Intangible Plant, 7 year	14.29%	14.29%	0.00%
Intangible Plant, 15 year	6.67%	6.67%	0.00%

100/1.98 = 50.41

CC: SK

Entergy

Entergy Services, LLC
639 Loyola Avenue (70113)
P.O. Box 61000
New Orleans, LA 70161-1000
Tel 504 576 6825
Fax 504 576 5579
lhand@entergy.com

Lawrence J. Hand, Jr.
Associate General Counsel
Legal Services - Regulatory

March 3, 2020

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Via Fax (225) 342-0877 & UPS

Ms. Terri Lemoine Bordelon
Records Division
Louisiana Public Service Commission
P. O. Box 91154
Baton Rouge, Louisiana 70821-9154

Re: *Ex Parte:* Application of Entergy Louisiana, LLC for Approval to Construct Lake Charles Power Station, and for Cost Recovery (LPSC Docket No. U-34283)

Dear Ms. Bordelon:

Attached are an original and three copies of the current estimate of the first-year non-fuel revenue requirement of Lake Charles Power Station which is currently expected to be in-service by May 1, 2020, but could occur sooner or later than that date. This estimate is submitted in accordance with Order No. U-34283 which requires Entergy Louisiana, LLC to make "an additional update to the estimated first-year revenue requirement" 60 days prior to the expected in-service date. *See* Order No. U-34283 at page 3. By copy of this letter, the compliance submission is being provided to the official service list in Docket No. U-34283. Please retain the original and two copies for your files and return a date-stamped copy to me in the enclosed, self-addressed envelope.

Please let me know if you have any questions. Otherwise, thank you for your assistance with this matter.

Sincerely,

Lawrence J. Hand, Jr.

LJH/rdm

Enclosures
cc: Official Service List (w/enclosure by Email only)

Entergy Louisiana, LLC

LAKE CHARLES POWER STATION REVENUE REQUIREMENT

DERIVATION OF THE RATE BASE
(Dollars In Thousands)

Item	Beginning Of Year	End Of Year
Rate Base		
A. Plant In Service [1]	821,000	821,000
B. Accumulated Depreciation [1]	0	(25,615)
C. Accumulated Deferred Income Taxes [2]	0	0
D. Rate Base	821,000	795,385
E. Average Rate Base		808,192

Notes:

[1] Does not reflect $50.7 million of plant in service associated with transmission investment that will be recovered through the Transmission Recovery Mechanism of the Formula Rate Plan.

[2] The tax position of ELL, relative to the first year revenue requirement of Lake Charles Power Station, has not been finally determined. The amount of ADIT used to calculate the Average Rate Base is subject to change, based on ELL's then-existing Net Operating Losses for tax purposes.

Annual Depreciation: $25,615
Plant in Service: $821,000
Depreciation Rate: 3.12%
Useful Life: 32.05 years

FILED WITH
Executive Secretary
November 14, 2012
IOWA UTILITIES BOARD
RPU-2012-0003

MARSHALLTOWN GENERATING STATION

Iowa Utilities Board

Application for

Ratemaking Principles

Docket No. RPU-2012-0003

Interstate Power and Light Company

MGS Project is placed in service; provided, however, that the prudence of the cost above the threshold defined under Ratemaking Principle No. 3.5 may be disputed by any party and shall be subject to determination by the Board.

For purposes of determining the first interim or final rates which become effective after the date the IPL MGS Project is placed in service, the depreciable life shall be 35 years. (See direct testimony of Mr. Nielsen.)

3.4 **Cost Cap - Prudence.** IPL shall be permitted to include in rates the actual costs of the IPL MGS Project, defined in Ratemaking Principle No. 3.5 without the need to establish prudence or reasonableness. IPL shall be required to establish the prudence and reasonableness of any IPL investment costs in excess of the cost cap amount defined in Ratemaking Principle No. 3.5 before the Iowa jurisdictional portion of such excess can be included in rates. (See direct testimony of Ms. Mattes.)

3.5 **Cost Cap.** The cost cap amount shall be $700 million, including the facility, transmission interconnection costs and owner's costs, for a facility with nominal capacity of 600 MW, plus or minus 5 percent. The amount above is exclusive of its transmission provider's delivery systems network upgrades, as defined in Ratemaking Principle No. 3.6, and AFUDC. (See direct testimony of Ms. Mattes, Mr. Hookham and Mr. Bauer.)

3.6 **Transmission Upgrades.** Should IPL become responsible for reimbursing its transmission provider for the capital costs associated with transmission network upgrades under revised MISO Schedule FF (or replacement schedule) at the time of the network upgrades, IPL shall be entitled to recover those capital costs charged to IPL by its transmission provider under FERC-approved tariffs. (See direct testimony of Mr. Bauer.)

3.7 **Treatment of AFUDC.** Interest costs incurred on the IPL MGS Project will be capitalized using the appropriate AFUDC rates in effect during the

AUSLEY MCMULLEN

ATTORNEYS AND COUNSELORS AT LAW

123 SOUTH CALHOUN STREET
P.O. BOX 391 (ZIP 32302)
TALLAHASSEE, FLORIDA 32301
(850) 224-9115 FAX (850) 222-7560

December 30, 2020

VIA: ELECTRONIC FILING

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

In re: Petition of Tampa Electric Company for approval of its 2020 Depreciation and Dismantlement Study and Capital Recovery Schedules; Docket No. 2020____-EI

Dear Mr. Teitzman:

Attached for filing on behalf of Tampa Electric Company is a Petition for Approval of its 2020 Depreciation and Dismantlement Study and Capital Recovery Schedules ("Petition"), which includes its 2020 Depreciation Study as Exhibit H. The electronic files required by Rule 25-6.0436(4)(a), Florida Administrative Code, are being filed by hand delivery together with five (5) paper courtesy copies of the Petition and exhibits under a separate cover letter contemporaneously with the electronic filing of this Petition.

Thank you for your assistance in connection with this matter.

Sincerely,

J. Jeffry Wahlen

JJW/ne
Attachment

cc: J.R. Kelly and Charles J. Rehwinkel (OPC)
Jon Moyle (FIPUG)
Schef Wright (FRF)
Thomas Jernigan (FEA)
Mark Sundback (HUA)

WITNESS DIRECT TESTIMONY SUMMARY

Witness: Steven A. Rogers

Title: Senior Vice President – Financial Management for Dominion Generation

Summary:

Company Witness Steven A. Rogers provides a brief overview of the key points of the Company's proposed Greensville County Power Station project ("Project"), and introduces other Company witnesses. His testimony is responsive to the Schedule 46 requirement to provide information relative to the need and prudence of the proposed Project.

Greensville County Power Station will support a continued balance of demand and supply resources, in addition to wholesale market purchases, and will serve as a prudent addition to Dominion Virginia Power's generating fleet. The proposed project has the following attributes:

- Economically superior choice to meet customer needs for baseload/intermediate capacity and energy;
- One of the most efficient natural gas-fueled power plants in the country utilizing proven technology and will consume less fuel to generate the same amount of electricity than older designs;
- Estimated low installed cost of $837/kW, with approximately 83% of the total $1.33 billion cost, excluding financing costs, fixed by contract;
- Positive environmental attributes including a low carbon intensity, lower water usage, and a wastewater discharge plan that minimizes the impact to rivers and streams;
- Fueling approach includes firm transportation and commodity supply arrangements to allow access to abundant, reliable and low cost natural gas supplies;
- Location takes advantage of fuel and electric transmission infrastructure improvements undertaken for the Brunswick station; and
- Project provides significant economic development benefits provided for the locality, region and state.

transmission interconnection facilities (the "Project" or "Greensville Project"). The Company proposes to have the power station in operation by December 2018. The Company is also requesting Commission approval of a rate adjustment clause, designated Rider GV, under § 56-585.1 A 6 ("Subsection A 6") of the Code of Virginia ("Va. Code") for timely and current recovery of the costs of the Project, which in total are estimated at $1.33 billion, excluding financing costs.

Specifically, I will provide a brief overview of the key points of the Company's proposal, and I will introduce other Company witnesses, who will provide further details concerning the Project in their direct testimonies in this case. In addition, my testimony is responsive to the Schedule 46 requirement to provide information relative to the need and prudence of the proposed Project.

Q. Mr. Rogers, are you sponsoring an exhibit in this proceeding?

A. Yes. I am sponsoring Exhibit 1 to the Company's Application which includes the Company's responses to 20 VAC 5-302-20(1), (2), (3), (4), and (6) and 20 VAC 5-302-10, Par. 1(ii).

Q. Why is the Company proposing this particular project to the Commission? (20 VAC 5-302-10, Par. 1(v); 20 VAC 5-302-20(14))

A. We are proposing the Project for several reasons. The Greensville County Power Station will be capable of producing enough electricity to power nearly 400,000 homes while offering customers numerous benefits over the 36 year life of the facility. Below is a highlight of the key attributes:

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition by Duke Energy Florida, LLC for limited proceeding to approve 2021 Settlement Agreement, including general base rate increases	DOCKET NO. ___________
In re: Petition by Duke Energy Florida, LLC for limited proceeding for recovery of incremental storm restoration costs related to Hurricane Michael	DOCKET NO. 20190110-EI
In re: Petition by Duke Energy Florida, LLC for limited proceeding for recovery of incremental storm restoration costs related to Hurricane Dorian and Tropical Storm Nestor.	DOCKET NO. 20190222-EI

2021 SETTLEMENT AGREEMENT

WHEREAS, Duke Energy Florida, LLC ("DEF" or "Company") has taken all necessary steps, including the preparation of Minimum Filing Requirements ("MFRs"), cost of service studies, depreciation and dismantlement studies, a storm reserve study, and tariffs, to prepare, and would have, with absolute certainty, filed, a general base rate proceeding with the Florida Public Service Commission ("FPSC" or "Commission") in March 2021 to request new rates to be set effective January 1, 2022 and January 1, 2023;

WHEREAS, certain parties, including but not limited to the Office of Public Counsel ("OPC"), PCS White Springs ("PCS"), Nucor Steel Florida, Inc. ("Nucor"), and the Florida Industrial Power Users Group ("FIPUG") (collectively, the "Intervenor Groups") would have intervened and challenged DEF's case, when it was filed;

WHEREAS, DEF and the Intervenor Groups (collectively, the "Parties" and any one of the Parties individually, a "Party") desired to avoid the expense and time associated that are implemented before the effective date of the applicable federal or state income tax rate change will be adjusted as part of the overall method outlined in Paragraph 9 and section b. of Paragraph 18.

Depreciation, Dismantlement, and Storm Reserve Studies

19. The Parties agree that the Dismantlement Study, as filed by DEF on December 31, 2020 and attached hereto as Exhibit 6, should be approved without changes. DEF will be permitted to defer to a regulatory asset the impact of the cost increase during the term of the 2021 Settlement Agreement, and the Parties agree not to oppose approval of the recovery of the total regulatory asset in DEF's next base rate proceeding over a period not to exceed five years.

20. The Parties agree that the Storm Reserve Study filed by DEF on December 31, 2020, has been modified to reflect no increase to the current $132 million reserve that is currently in DEF's base rates. The modified Storm Reserve Study is attached to this 2021 Settlement Agreement as Exhibit 7 and should be approved as modified.

21. The Parties agree that the Depreciation Study filed by DEF on December 31, 2020 has been modified to reflect the changes detailed in Paragraphs 21(a) through (c) below and should be approved as modified. The modified Depreciation Study is attached to this 2021 Settlement Agreement as Exhibit 8.

a. Distribution (excluding account 373-Street Lighting and Signal Systems) and Transmission rates will remain at the same level as reflected in the 2009 Depreciation Study;
b. The useful lives of Combined Cycle units are 40 years; and
c. DEF will delay the start of amortization of the Cost of Removal ("COR") Regulatory Asset to January 1, 2025 and the recovery period of this regulatory

**BEFORE
THE PUBLIC SERVICE COMMISSION OF
SOUTH CAROLINA**

DOCKET NO. 2022-254-E

In the Matter of:	)	
	)	**DIRECT TESTIMONY OF**
Application of Duke Energy Progress, LLC For	)	**JOHN J. SPANOS**
Authority to Increase its Electric Rate Schedules	)	**FOR DUKE ENERGY**
and Charges	)	**PROGRESS, LLC**
	)	

the license or relicense dates. A life span of 40-53 years was estimated for the combustion turbines. The primary life span of 40 years was estimated for the combustion turbines, however, a couple facilities were extended to meet possible load changes. The combined cycle units are relatively new units with a commonly used 40-year life span estimate. All solar facilities have recently been constructed and will have a 30-year life span.

A summary of the major year in service, depreciable life span and depreciable life date for each power production unit follows:

Depreciable Group	Major Year in Service	Depreciable Life Date	Depreciable Life Span
Steam Production Plant			
Mayo Unit 1	1983	2028	45
Roxboro Unit 1	1966	2028	62
Roxboro Unit 2	1968	2028	60
Roxboro Unit 3	1973	2027	54
Roxboro Unit 4	1980	2027	47
Nuclear Production Plant			
Brunswick Unit 1	1977	2056	79
Brunswick Unit 2	1975	2054	79
Harris Unit 1	1987	2066	79
Robinson Unit 1	1971	2050	79
Hydraulic Production Plant			
Blewett	1912	2055	143
Marshall	1910	2035	125
Tillery	1928	2055	127
Walters	1930	2034	104
Other Production Plant			
Asheville	1999	2039	40
Asheville CC	2019	2059	40
Blewett	1971	2030	59
Darlington Units 1-11	1974	2020	46
Darlington Units 12 and 13	1997	2037	40
H.F. Lee (Wayne County) Units 10-13	2000	2040	40
H.F. Lee (Wayne County) Unit 14	2009	2049	40

Gannett Fleming

Excellence Delivered ***As Promised***

March 5, 2016

Florida Power and Light Company
700 Universe Boulevard
Juno Beach, FL 33408

Attention: Mr. Keith Ferguson
Assistant Controller

Ladies and Gentlemen:

Pursuant to your request, we have conducted a depreciation study related to the electric plant of Florida Power and Light Company as of December 31, 2017. The attached report presents a description of the methods used in the estimation of depreciation, the summary of annual and accrued depreciation, the statistical support for the service life and net salvage estimates, and the detailed tabulations of annual and accrued depreciation.

Respectfully submitted,

GANNETT FLEMING VALUATION
AND RATE CONSULTANTS, LLC

NED ALLIS
Supervisor, Depreciation Studies

RICHARD CLARKE
Director, Western U.S. Services

RC:krm

059947.100

Gannett Fleming Valuation and Rate Consultants, LLC

P.O. Box 67100 • Harrisburg, PA 17106-7100 | 207 Senate Avenue • Camp Hill, PA 17011-2316
t: 717.763.7211 • f: 717.763.4590

www.gannettfleming.com

based on a number of factors, including the operating characteristics of the facilities, the type of technology used at each plant, environmental and other regulations, experience in the industry, current forecasted life spans, and the Company's outlook for each facility.

A description of each generating facility, as well as the bases for the estimated probable retirement dates and estimated interim survivor curves can be found in the section beginning on page X-2. Generally, the recommended retirement dates are consistent with 50 year life spans for the Company's steam units, 60 year life spans for the Company's nuclear units, 40 year life spans for the Company's combined cycle and new peaker units, and 30 year life spans for the Company's solar units. The probable retirement dates used in this study for each of the production facilities are summarized below. The same retirement date was used for each unit at the facility unless otherwise noted.

GENERATING PLANT	PROBABLE RETIREMENT DATE
STEAM PRODUCTION	
Manatee	2028
Martin	2031
Scherer	2039
St. Johns River Power Park	2038
NUCLEAR PRODUCTION	
St. Lucie Common	2043
St. Lucie Unit 1	2036
St. Lucie Unit 2	2043
Turkey Point Common	2033
Turkey Point Unit 3	2032
Turkey Point Unit 4	2033