approval, modification, or rejection of the individual sheets of the tariff proposal. Responses to Staff's recommendation shall be filed no later than 15 days after the filing of the tariff. The Commission shall by letter approve, modify, or reject each tariff sheet, effective the date of the letter.

10. The tariff sheets shall be deemed approved and shall become effective on the expiration of 20 days from the date of filing, in the absence of written notification of modification or rejection by the Commission. If any sheets are modified or rejected, SWEPCO shall file proposed revisions of those sheets in accordance with the Commission's letter within ten days of the date of that letter, and the review procedure set out above shall apply to the revised sheets.

11. Copies of all tariff-related filings shall be served on all parties of record.

12. All other motions, requests for entry of specific findings of fact and conclusions of law, and any other requests for general or specific relief, if not expressly granted, are denied.

Signed: August 27, 2021.

ANDREW LUTOSTANSKI
ADMINISTRATIVE LAW JUDGE
STATE OFFICE OF ADMINISTRATIVE HEARINGS

STEVEN H. NEINAST
ADMINISTRATIVE LAW JUDGE
STATE OFFICE OF ADMINISTRATIVE HEARINGS

ROBERT H. PEMBERTON
ADMINISTRATIVE LAW JUDGE
STATE OFFICE OF ADMINISTRATIVE HEARINGS

CASSANDRA QUINN
ADMINISTRATIVE LAW JUDGE
STATE OFFICE OF ADMINISTRATIVE HEARINGS

Attachment A

SOAH DOCKET NO. 473-21-0538
PUC DOCKET NO. 51415
COMPANY NAME Southwestern Electric Power Company
TEST YEAR END 31-Mar-20

PFD Schedule I
Total Company Revenue Requirement
Page 1 of 1

	Company Test Year Total	Company Adjustments To Test Year	REBUTTAL Co Requested Test Year Total Electric	PFD Adj To Company Request	PFD Adjusted Total Electric
	(a)	(b)	(c) = (a) + (b)	(d)	(e) = (c) + (d)
REVENUE REQUIREMENT					
Operations & Maintenance	1,096,640,498	(545,239,261)	551,401,239	(23,625,522)	527,775,717
Loss on Disposition of Utility Property	653,208	(490,000)	163,208	0	163,208
Accretion Expense	3,484,561	0	3,484,561	0	3,484,561
Amortization Expense	17,994,221	5,940,656	23,934,877	3,310,118	27,244,995
Depreciation Expense	236,316,513	1,872,435	238,188,948	(6,258,253)	231,930,695
Taxes Other Than Income Taxes	100,527,332	(566,762)	99,960,570	(6,106,245)	93,854,325
Federal Income Taxes	7,262,011	65,052,207	65,052,207	(18,584,325)	46,467,882
Return on Invested Capital	263,445,627	123,780,532	387,226,159	(58,606,702)	328,619,457
Other State Income Taxes	(1,364,764)	1,364,764	0		
TOTAL	**1,724,959,207**	**(348,285,429)**	**1,369,411,769**	**(109,870,929)**	**1,259,540,840**

Attachment A

SOAH DOCKET NO. 473-21-0538
PUC DOCKET NO. 51415
COMPANY NAME Southwestern Electric Power Company
TEST YEAR END 31-Mar-20

PFD Schedule II
O&M Expense
Page 1 of 2

OPERATIONS AND MAINTENANCE EXPENSE	Acct. No	Company Test Year Total (a)	Company Adjustments To Test Year (b)	REBUTTAL Co Requested Test Year Total Electric (c)	PFD Adj To Company Request (d)	PFD Adjusted Total Electric (e) = (c) + (d)
Operations & Maintenance:						
Prod. Operation and Supr	500	21,645,237	(1,299,105)	20,346,132	(2,711,267)	17,634,865
Fuel-Reconcilable	501	399,631,093	(382,531,543)	17,099,550	(49,336)	17,050,214
Fuel-Non Reconcilable	501	0	0	0	(3,266,584)	(3,266,584)
Steam Expenses	502	19,098,323	(8,212,796)	10,885,527	(1,319,045)	9,566,482
Electric Expenses	505	10,576,275	(532,822)	10,043,453	(431,460)	9,611,993
Misc Steam Power Expenses	506	16,480,428	2,024,792	18,505,220	(3,831,596)	14,673,624
Rents	507	3,339	0	3,339	(634)	2,705
Allowance Expense	509	333,862	(41,727)	292,135	0	292,135
Maintenance Supv and Eng	510	5,221,988	(367,421)	4,854,567	(391,247)	4,463,320
Maintenance of structures	511	5,930,496	(99,368)	5,831,128	(235,335)	5,595,793
Maintenance of boiler plant	512	36,899,429	(769,067)	36,130,362	(3,976,004)	32,154,358
Maintenance of electric plant	513	8,232,373	(192,019)	8,040,354	(184,768)	7,855,586
Maintenance of misc steam plant	514	7,151,128	(164,156)	6,986,972	(1,095,596)	5,891,376
Operation supervision and engineering	517	0	0	0	(456)	(456)
Maintenance Supv and Eng	541	0	0	0	(355)	(355)
Operation Supv and Eng	546	4,833	(8,710)	(3,877)	(368)	(4,245)
Operation Fuel	547	10,520,437	(10,520,437)	0	(64)	(64)
Operation Generation Exp	548	257,827	(11,366)	246,461	1,512	247,973
Misc. Other Power Gen Exp	549	6,031	0	6,031	(3)	6,028
Operation Rents	550	0	0	0	0	0
Maintenance Supv and Eng	551	(35)	0	(33)	1	(32)
Maintenance of structures	552	961	60	1,021	7	1,028
Maintenance of generating and ele	553	827,970	(17,633)	810,337	1,500	811,837
Maint of Misc Other power gen plant	554	81,759	0	81,759	0	81,759
Purchased Power	555	207,609,120	(200,987,454)	6,621,666	0	6,621,666
System Control & Load Dispatch	556	1,494,472	(103,460)	1,391,012	(99,295)	1,291,717
System Control & Dispatch Other	557	1,822,709	1,255,487	3,078,196	(194,920)	2,883,276
Transmission Ops Supr & Engr	560	10,546,443	(565,371)	9,981,072	(527,202)	9,453,870
Transmission Load Dispatching -reliability	5611	0	0	0	0	0
Monitor and operate transmission-sys	5612	1,073,774	(43,835)	1,029,939	(66,502)	963,437
Trans service and scheduling	5613	417	0	417	0	417
Schedule system controland disatch ser	5614	11,545,148	0	11,545,148	0	11,545,148
Reliability planning and standards deve	5615	251,831	(9,586)	242,245	(15,744)	226,501
Reliability planning and standards deve s	5618	914,530	0	914,530	0	914,530
Transmission Station Equipment	562	1,235,007	(22,879)	1,212,128	1,318	1,213,446
Trans OH Line Expense	563	430,199	(2,044)	428,155	(1,111)	427,044
Underground Line Expenses	564	1,573	19	1,592	0	1,592
Transmission of Electricity by Others	565	73,241,705	79,285,200	152,526,905	0	152,526,905
Misc. Transmission Expenses	566	2,924,908	452,807	3,377,715	(92,286)	3,285,429
Rents	567	25,508	(1)	25,507	(9)	25,498
SPP Admin - MAM&SC	5757	2,366,891	0	2,366,891	0	2,366,891
Maint. Supv. And Eng.	568	15,702	(864)	14,838	(617)	14,221
Maint. of Structures	569	36,341	(195)	36,146	32	36,178
Maint. of computer hardware	5691	9,937	(312)	9,625	(621)	9,004
Maint. of computer software	5692	642,128	(5,624)	636,504	(9,777)	626,727
Maint. of computer equip	5693	56,944	0	56,944	0	56,944
Transmission Maint Station Equip	570	2,651,013	(78,372)	2,572,641	(6,307)	2,566,334
Transmission Maint OH Line Exp	571	14,533,315	(27,704)	14,505,611	1,206	14,506,817
Maint. of Underground Lines	572	11,239	111	11,350	0	11,350
Maint. of Misc. Transmission	573	85,869	(4,658)	81,211	(82)	81,129
Distribution Ops Supr & Engr	580	2,632,859	(167,391)	2,465,468	(154,371)	2,311,097
Distribution Load Dispatching	581	62,791	(1,291)	61,500	0	61,500
Distribution Station Expenses	582	749,112	(21,825)	727,287	(2,564)	724,723
Distribution OH Line Expenses	583	1,752,384	(223,813)	1,528,571	(10,170)	1,518,401
Underground Line Expenses	584	1,383,497	(46,597)	1,336,900	3,632	1,340,532
Street Lighting & Signal Sys	585	162,030	(3,872)	158,158	189	158,347
Meter Expenses	586	3,819,316	(302,033)	3,517,283	6,241	3,523,524
Customer Installations	587	410,742	(20,716)	390,026	1,916	391,942
Miscellaneous Distribution Exp	588	20,017,606	2,087,692	22,105,298	(4,186)	22,101,112
Rents	589	889,843	0	889,843	0	889,843
Distribution Maint Supr & Engr	590	166,883	(13,911)	152,972	337	153,309
Maint. of Structures	591	39,491	(209)	39,282	51	39,333
Distribution Maint Station Equip	592	2,040,674	(46,290)	1,994,384	(908)	1,993,476
Distribution Maint OH lines	593	57,550,019	(1,092,825)	56,457,194	38,430	56,495,624
Underground Line Expenses	594	660,415	(15,706)	644,709	1,351	646,060
Dist Maint Line Trnf, Regulators	595	140,636	(8,001)	132,635	533	133,168
MaintStreet Light & Signal Sys	596	303,595	(18,992)	284,603	978	285,581
Maintenance of Meters	597	442,928	(28,138)	414,790	2,491	417,281
Maint of Misc Distr Plant	598	371,393	(15,560)	355,833	1,488	357,321
Supervision - Customer Accts	901	781,491	(60,532)	720,959	(1,997)	718,962
Meter Reading Exp	902	2,614,840	(145,207)	2,469,633	3,185	2,472,818
Customer Records & Collection	903	17,797,556	(75,924)	17,721,632	(595,255)	17,126,377
Customer Deposit Interest	903.2	0	0	0	0	0
Uncollectible Accounts	904	724,395	0	724,395	0	724,395
Miscellaneous	905	101,498	(323)	101,175	(1,972)	99,203
Factoring Expense	426.5	9,711,825	(1,296,219)	8,415,606	0	8,415,606
Factoring Expense on Revenue Deficiency			1,117,582	1,117,582	(567,072)	550,510
Factoring Rate on Revenue Deficiency				0.0048258000000		0.0051612600000
Customer Service and Information	906	0	0	0	0	0
Supervision	907	7,429,119	(6,739,057)	690,062	(1,311)	688,751
Customer Assistance	908	15,029,496	(12,749,804)	2,279,692	8,601	2,288,293
Information & Instr Advertising	909	0	0	0	0	0
Misc. Cust. Service and Information	910	27,409	(1,365)	26,044	(965)	25,079
Sales Supervision	911	2,198	0	2,198	0	2,198
Demonstrating & Selling Exp	912	265,976	(6,786)	259,190	(200)	258,990
Advertising Expense	913	0	0	0	0	0
Misc. Sales Expense	916	0	0	0	0	0
Sales Expense	917	0	0	0	0	0
		0	0	0	0	0
TOTAL Operations & Maintenance		**1,024,512,494**	**(543,499,166)**	**481,013,330**	**(19,774,563)**	**461,238,767**

Attachment A

SOAH DOCKET NO. 473-21-0538
PUC DOCKET NO. 51415
COMPANY NAME Southwestern Electric Power Company
TEST YEAR END 31-Mar-20

PFD Schedule II
O&M Expense
Page 2 of 2

OPERATIONS AND MAINTENANCE EXPENSE	Acct. No	Company Test Year Total (a)	Company Adjustments To Test Year (b)	REBUTTAL Co Requested Test Year Total Electric (c)	PFD Adj To Company Request (d)	PFD Adjusted Total Electric (e) = (c) + (d)
Administrative & General: (WP/A)						
Admin & General Salaries	920	32,325,718	(4,055,803)	28,269,915	(1,457,325)	26,812,590
Office Supplies & Exp	921	2,947,644	(1,212,661)	1,734,983	(54)	1,734,929
Admin Expenses Transferred	922	(4,430,969)	(59,256)	(4,490,225)	(15,049)	(4,505,274)
Outside Services	923	9,712,500	7,253	9,719,753	(70)	9,719,683
Property Insurance	924	2,428,223	1,689,700	4,117,923	(2,132,274)	1,985,649
Injuries & Damages	925	3,657,677	(29,527)	3,628,150	493	3,628,643
Employee Pensions & Benefits	926	13,373,091	2,799,757	16,172,848	(1,638)	16,171,210
Regulatory Commission Exp	928	2,624,761	(2,540,746)	84,015	(231,756)	(147,741)
Duplicate Charges	929	0	0	0	0	0
General Advertising Exp	9301	318,019	(1,129)	316,890	(24)	316,866
Miscellaneous	9302	1,724,290	1,732,377	3,456,667	(12,049)	3,444,618
Rents	931	1,008,537	(585)	1,007,952	0	1,007,952
Maint. Of General Plant	935	6,436,014	(69,422)	6,366,592	(1,213)	6,365,379
TOTAL Administrative & General		72,125,505	(1,740,042)	70,385,463	(3,850,959)	66,534,504
TOTAL O & M EXPENSE		**1,096,637,999**	**(545,239,208)**	**551,398,793**	**(23,625,522)**	**527,773,271**
	8140	53	-53	0		0
Gains/Losses Disposition Allowances	4118, 4119	4	0	4		4
Operations Expense - Non associated	4010	2442	0	2,442		2442
TOTAL		**1,096,640,498**	**(545,239,261)**	**551,401,239**		**527,775,717**

Attachment A

SOAH DOCKET N 473-21-0538
PUC DOCKET NO 51415
COMPANY NAME Southwestern Electric Power Company
TEST YEAR END 31-Mar-20

PFD Schedule III
Invested Capital
Page 1 of 1

	Acct. No	Company Test Year Total (a)	Company Adjustments To Test Year (b)	REBUTTAL Co Requested Test Year Total Electric (c)	PFD Adj To Company Request (d)	PFD Adjusted Total Electric (e) = (c) + (d)
INVESTED CAPITAL						
Plant in Service	101	9,262,354,949	59,960,988	9,322,315,937	(339,874,755)	8,982,441,182
Accumulated Depreciation	108	(3,329,123,077)	104,944,688	(3,224,178,389)	316,560,953	(2,907,617,436)
Net Plant In Service		5,933,231,872	164,905,676	6,098,137,548	(23,313,802)	6,074,823,746
Construction Work in Progress	107	226,392,894	(226,392,894)	0	0	0
Plant Held for Future Use	105	1,044,101	(823,186)	220,915	0	220,915
Dolet Hills Mine FAS 143 ARO Asset	101.6	61,976,617	(61,976,617)	0	0	0
Capitalized leases	1011	105,842,819	(105,842,819)	0	0	0
Accumulated Provision - Leased Assets		(31,065,524)	31,065,524	0		
Completed Construction Not Classified	106	319,647,154	0	319,647,154	0	319,647,154
Plant Acquisition	114	18,043,976	(18,043,976)	0	0	0
Accumulated Provision - Plant Acquisition		(18,043,976)	18,043,976	0	0	0
Other Electric Plant Adjustments	116				0	0
Turk Impairments		(51,821,999)		(51,821,999)		(51,821,999)
Tx Trans Veg Mgmt Cost Writeoff		(1,471,585)		(1,471,585)		(1,471,585)
Tx Dist Veg Mgmt Cost Writeoff		(3,993,357)		(3,993,357)		(3,993,357)
SERP		(637,842)		(637,842)		(637,842)
CWIP Fin Based Incentive		(12,432,748)	42,000	(12,390,748)	(84,000)	(12,474,748)
RWIP Fin Based Incentive		(499,903)		(499,903)		(499,903)
Working Cash Allowance		(145,220,159)	0	(145,220,159)	3,058,346	(142,161,813)
Materials and Supplies	154	70,436,747	(913,340)	69,523,407	0	69,523,407
Fuel Inventories	151/152	105,918,091	(19,211,748)	86,706,343	(28,528,383)	58,177,960
Prepayments	165	17,148,962	83,452,444	100,601,406	0	100,601,406
SFAS #109 Regulatory Assets & Liabilities	1823/254	(412,675,887)	35,506,181	(377,169,706)	0	(377,169,706)
Accumulated DFIT - Reg Assets and Liabilities		412,675,897	(35,506,191)	377,169,706	0	377,169,706
Accumulated Deferred Federal Income Taxes		(1,270,549,476)	291,719,543	(978,829,933)	(455,122,490)	(1,433,952,423)
Rate Base - Other		0	0	0		0
IPP Credit	2530067	(7,532,556)	0	(7,532,556)	0	(7,532,556)
Trading Deposits	1340018/1340	2,092,064	0	2,092,064	0	2,092,064
Excess Earnings Deferral	2540052	(2,453,476)	0	(2,453,476)	0	(2,453,476)
T.V. Pole Attachments	2530050	(831,313)	0	(831,313)	0	(831,313)
Sabine Mine Reclamation	2420059	0	(64,960,236)	(64,960,236)	0	(64,960,236)
Investment in Oxbow		0	16,576,181	16,576,181	(16,576,181)	0
Electric Plant Purchased or Sold		64,005	(64,005)	0		
SFAS #106 Medicare Subsidy		2,533,221	0	2,533,221		2,533,221
Customer Deposits		(65,072,259)	0	(65,072,259)	0	(65,072,259)
TOTAL INVESTED CAPITAL (RATE BASE)		**5,252,746,360**	**107,576,513**	**5,360,322,873**	**(520,566,510)**	**4,839,756,363**
RATE OF RETURN		**5.02%**		**7.22%**		**6.79%**
RETURN ON INVESTED CAPITAL		**263,445,627**	**123,780,532**	**387,226,159**	**(58,606,702)**	**328,619,457**

Attachment A

SOAH DOCKET NO. 473-21-0538
PUC DOCKET NO. 51415
COMPANY NAME Southwestern Electric Power Company
TEST YEAR END 31-Mar-20

PFD Schedule IV
Depreciation, Amortizatioin & Acretion Expense
Page 1 of 1

	Acct. No	Company Test Year Total (a)	Company Adjustments To Test Year (b)	REBUTTAL Co Requested Test Year Total Electric (c)	PFD Adj To Company Request (d)	PFD Adjusted Total Electric (e) = (c) + (d)
AMORTIZATION EXPENSE						
Amortization Exp	404	17,421,930	3,435,169	20,857,099	0	20,857,099
Amort of Elec Plt Aqui	406	0	0	0	0	0
Amort Exp (Reg Debit)	4073	860,876	2,288,902	3,149,778	3,310,118	6,459,896
Amort Exp (Reg Credit)	4074	(288,585)	216,585	(72,000)	0	(72,000)
Total Amortization		17,994,221	5,940,656	23,934,877	3,310,118	27,244,995
ACRETION EXPENSE						
Acretion Expense	4111	3,484,561	0	3,484,561	0	3,484,561
DEPRECIATION EXPENSE						
Production	4030.1	118,198,563	1,104,459	119,303,022	(3,335,777)	115,967,245
Transmission	4030.2	49,421,354	(1,487,507)	47,933,847	(1,926,373)	46,007,474
Distribution	4030.3	61,585,051	2,596,244	64,181,295	(996,103)	63,185,192
General	4030.4	7,111,545	(340,761)	6,770,784	0	6,770,784
Total Depreciation Expense		236,316,513	1,872,435	238,188,948	(6,258,253)	231,930,695
TOTAL DEPRECIATION, ACRETION & AMT EXP		257,795,295	7,813,091	265,608,386	(2,948,135)	262,660,251
Loss on Disposition Util Prop	411	653,208	(490,000)	163,208		163,208
TOTAL		**$ 258,448,503**	**$ 7,323,091**	**$ 265,771,594**	**$ (2,948,135)**	**$ 262,823,459**

Attachment A

SOAH DOCKET NO. 473-21-0538
PUC DOCKET NO. 51415
COMPANY NAME Southwestern Electric Power Company
TEST YEAR END 31-Mar-20

PFD Schedule V
Taxes Other Than FIT

		Company Test Year Total	Company Adjustments To Test Year	REBUTTAL Co Requested Test Year Total Electric	PFD Adj To Company Request	PFD Adjusted Total Electric
		(a)	(b)	(c)	(d)	(e) = (c) + (d)
TAXES OTHER THAN FIT						
Non Revenue Related						
Ad Valorem Taxes-Texas		19,752,787	1,626,874	21,379,661	(3,255,645)	18,124,016
Ad Valorem Taxes-Other States		42,662,719	3,422,126	46,084,845	0	46,084,845
Total Property		62,415,506	5,049,000	67,464,506	(3,255,645)	64,208,861
Payroll Taxes						
FICA		6,971,664	45,867	7,017,531	(258,162)	6,759,369
FUTA		40,193	0	40,193	0	40,193
SUTA		40,777	0	40,777	0	40,777
Total Payroll		7,052,634	45,867	7,098,501	(258,162)	6,840,339
Franchise Taxes Texas	408.33	0	0	0	0	0
Other States		4,393,405	(4,393,405)	0	0	0
Total Franchise		4,393,405	(4,393,405)	0	0	0
Other Sales and Use Tax		39,720	(39,720)	0	0	0
Other		85,990	(84,295)	1,695	0	1,695
Total Other		125,710	(124,015)	1,695	0	1,695
TOTAL NON REVENUE RELATED TAXES		**73,987,255**	**577,447**	**74,564,702**	**(3,513,807)**	**71,050,895**
Revenue Related						
State Gross Receipts - Texas		6,215,215	2,454,209	8,669,424	(1,231,432)	7,437,992
State Gross Receipts - Other		8	0	8	0	8
Local Gross Receipts - Texas		9,357,340	(3,757,069)	5,600,271	(792,642)	4,807,629
Local Gross Receipts - Other		8,327,064	0	8,327,064	0	8,327,064
PUC Assessment - Texas		989,177	390,598	1,379,775	(195,988)	1,183,787
PUC Assessment - Other		1,188,520	0	1,188,520	0	1,188,520
State Gross Margins - Texas		462,753	(231,947)	230,806	(372,377)	(141,571)
TOTAL REVENUE RELATED TAXES		**26,540,077**	**(1,144,209)**	**25,395,868**	**(2,592,438)**	**22,803,430**
TOTAL TAXES OTHER THAN INCOME TAXES		**100,527,332**	**(566,762)**	**99,960,570**	**(6,106,245)**	**93,854,325**

Attachment A

SOAH DOCKET NO. 473-21-0538
PUC DOCKET NO. 51415
COMPANY NAME Southwestern Electric Power Company
TEST YEAR END 31-Mar-20

PFD Schedule VI
Federal Income Taxes
Page 1 of 1

FEDERAL INCOME TAXES - METHOD 1

	113,324,648	(10,903,917)	102,420,731
	1,458,080	0	1,458,080
	3,719,670	4,664,032	8,383,702
Return	0	0	0
	0	0	0
Less:	0	0	0
Synynchronized Interest	73,596	0	73,596
DITC Amortization	0	0	0
Amortization of Protected Excess DFIT	16,602,098	0	16,602,098
Preferred Dividend Exclusion	0	0	0
Medicare Subsidy	135,178,092	(6,239,885)	128,938,207
AFUDC		0	0
Restricted Stock Plan - Tax Deduction		0	0
Prior Year T/R Adjustment	542,023	0	542,023
Accelerated Book Depletion	10,069,545	0	10,069,545
Parent Company Tax Loss Saving	1,538,774	0	1,538,774
TOTAL	0	0	0
Plus:		0	0
AFUDC			0
Business Meals not Deductible	12,150,342	0	12,150,342
Additional Depreciation			
Stock based Compensation			
AFUDC-BIP Amortization			
FAS 106 (Medicare Reimbursement)			
Business Meals Not Deductible			
TOTAL			

REBUTTAL

Co Requested Test Year Total Electric	**PFD Adj To Company Request**	**PFD Adjusted Total Electric**
(a)	**(b)**	**(c) = (a) + (b)**
387,226,159	(58,606,702)	328,619,457

TAXABLE COMPONENT OF RETURN	264,198,409	(52,366,816)	211,831,592
TAX FACTOR (1/1-.21)(.21)	26.582278%	26.582278%	26.582278%
TOTAL FIT BEFORE ADJUSTMENTS	**70,229,957**	**(13,920,293)**	**56,309,664**
Adjustments:			
Amortization of DITC	(1,458,080)	0	(1,458,080)
Amortization of Excess DFIT	(3,719,670)	(4,664,032)	(8,383,702)
	0	0	0
Prior Year T/R Adjustment	0	0	0
		0	0
TOTAL	(5,177,750)	(4,664,032)	(9,841,782)
		0	
TOTAL FEDERAL INCOME TAXES	**65,052,207**	**(18,584,325)**	**46,467,882**

PUBLIC UTILITY COMMISSION OF TEXAS
SOUTHWESTERN ELECTRIC POWER COMPANY
PUC DOCKET NO. 51415
PFD JURISDICTIONAL & FUNCTIONAL MODEL
FOR TEST YEAR JUNE 30, 2020

	TOTAL COMPANY			TEXAS RETAIL		
DESCRIPTION	TOTAL COMPANY REQUESTED AMOUNT	PFD ADJUSTMENT	PFD ADJUSTED TOTAL COMPANY	COMPANY REQUESTED TEXAS RETAIL	PFD ADJUSTMENT TO TEXAS RETAIL	PFD ADJUSTED TEXAS RETAIL
SUMMARY - EQUALIZED RETURN						
RATE BASE	5,360,322,879	(520,566,509)	4,839,756,370	2,025,542,720	(238,979,972)	1,786,562,748
RETURN	387,226,159	(58,606,701)	328,619,458	146,323,859	(25,016,248)	121,307,611
RATE OF RETURN ON RATE BASE	7.22%	-0.43%	6.79%	7.22%		6.79%
PRESENT O&M EXP	550,283,659	(23,625,522)	526,658,137	215,193,067	(14,433,904)	200,759,163
INCR IN 903-CUST ACCT & COLL FACTC	1,117,582		1,117,582	548,442	(26,200)	522,242
TOT OPERATION & MAINT EXP	551,401,241	(23,625,522)	527,775,719	215,741,509	(14,460,104)	201,281,405
DEPRECIATION & AMORTIZATION EXP	265,771,594	(2,948,135)	262,823,459	105,928,834	(3,999,442)	101,929,392
SO2 ALLOWANCE	4	0	4	1	0	1
NON-REVENUE TAXES OTHER THAN INC	74,564,702	(3,513,807)	71,050,895	28,266,008	(1,680,382)	26,585,626
REVENUE RELATED TAXES ARK	0	0	0	0	0	0
REVENUE RELATED TAXES LA	9,515,593	0	9,515,593	0	0	0
REVENUE RELATED TAXES TX	10,821,602	(2,592,438)	8,229,164	10,821,602	(935,821)	9,885,781
TOTAL TAXES OTHER THAN INCOME	94,901,897	(6,106,245)	88,795,652	39,087,610	(2,616,203)	36,471,407
REV RELATED TAX ON REVENUE DEFCIENCY	5,058,674		5,058,674	2,482,493	(118,595)	2,363,898
FED INCOME TAX LIABILITY	65,052,207	(18,584,325)	46,467,882	24,601,826	(7,502,124)	17,099,702
TOTAL OPERATING EXPENSES	982,185,617	(51,264,227)	930,921,390	387,842,273	(28,696,469)	359,145,805
COST OF SERVICE	1,369,411,776	(109,870,929)	1,259,540,848	534,166,132	(53,712,717)	480,453,415
TOTAL PROPOSED CEEDITS	(195,477,466)	0	(195,477,466)	(82,636,594)	4,826,353	(77,810,240)
BASE REVENUE REQUIREMENT	**1,173,934,310**	**(109,870,929)**	**1,064,063,381**	**451,529,538**	**(48,886,363)**	**402,643,175**

PUBLIC UTILITY COMMISSION OF TEXAS
SOUTHWESTERN ELECTRIC POWER COMPANY
PUC DOCKET NO. 51415
PFD CLASS-FUNCTIONAL SUMMARY
FOR TEST YEAR JUNE 30, 2020

	Generation Energy	Total Capacity				Total Capacity	Distribution Customer	Total Rate Base Revenue Requirement
		Generation Demand	Transmission Demand	Distribution Primary	Distribution Secondary			
1 Basic Residential	10,430,079	73,170,363	34,220,198	22,903,082	18,528,481	**148,822,124**	13,166,421	**172,418,624**
2								
3 General Service with Demand	1,018,314	7,812,815	3,644,839	3,046,980	2,466,402	**16,971,037**	1,492,041	**19,481,392**
4 General Service without Demand	322,184	2,511,009	1,172,995	1,201,655	974,293	**5,859,952**	1,123,696	**7,305,832**
5								
6 Cotton Gin	23,978	66,716	31,788	193,256	157,295	**449,056**	2,074	**475,107**
7								
8 Lighting and Power-Secondary	10,268,402	54,254,095	25,425,582	17,730,844	14,344,762	**111,755,284**	2,656,917	**124,680,603**
9 Lighting and Power-Primary	2,995,901	11,031,478	5,176,150	3,953,772	433,126	**20,594,525**	380,793	**23,971,220**
10								
11 Large Lighting and Power-Primary	734,000	3,315,901	1,550,824	244,304	133,551	**5,244,581**	217,532	**6,196,112**
12 Large Lighting and Power-Transmission	3,394,016	11,263,027	5,403,989	1,924	1,526	**16,670,465**	310,437	**20,374,918**
13								
14 Oilfield Primary	1,660,069	5,259,127	2,470,116	2,289,579	217,297	**10,236,119**	351,585	**12,247,773**
15 Oilfield Secondary	85,085	434,857	204,328	145,899	116,319	**901,402**	3,502	**989,989**
16								
17 Metal Melting-Primary	172,980	537,910	250,419	527,623	51,025	**1,366,977**	86,404	**1,626,361**
18 Metal Melting-Transmission	238,287	735,426	342,783	9,626	6,363	**1,094,198**	47,505	**1,379,990**
19 Metal Melting-Secondary	9,231	30,676	14,120	69,194	56,269	**170,259**	5,707	**185,197**
20								
21 Municipal Pumping	277,854	860,492	404,293	438,718	355,114	**2,058,617**	75,002	**2,411,473**
22 Municipal Service	129,406	529,183	246,432	222,058	178,929	**1,176,601**	170,688	**1,476,695**
23								
24 Municipal Lighting	130,007	391,774	178,231	337,876	273,149	**1,181,030**	1,136,591	**2,447,628**
25 Public Street and Highway	4,859	15,636	7,262	13,500	10,979	**47,377**	38,016	**90,252**
26								
27 Private, Outdoor, Area	237,573	734,190	334,465	637,573	515,915	**2,222,144**	2,055,495	**4,515,211**
28 Customer-Owned Lighting	32,476	97,873	44,872	91,950	74,565	**309,261**	27,165	**368,902**
29								
35 **Total**	**32,164,699**	**173,052,547**	**81,123,687**	**54,059,414**	**38,895,359**	**347,131,007**	**23,347,572**	**402,643,278**

PUBLIC UTILITY COMMISSION OF TEXAS
SOUTHWESTERN ELECTRIC POWER COMPANY
PUC DOCKET NO. 51415
PFD CLASS MODEL SUMMARY
FOR TEST YEAR JUNE 30, 2020

DESCRIPTION	RESIDENTIAL BASIC	RESIDENTIAL DG	GS W/ DEMAND	GS WO/ DEMAND	COTTON GIN	GS DG	LIGHT & POWER SEC	LIGHT & POWER PRI	LIGHT & POWER DG	LLP PRI
SUMMARY - EQUALIZED RETURN										
RATE BASE	761,788,151	605,497	86,016,949	31,250,884	1,934,195	50,400	558,732,246	105,446,858	704,730	28,092,780
RETURN	51,725,415	41,113	5,840,551	2,121,935	131,332	3,422	37,937,920	7,159,842	47,851	1,907,500
RATE OF RETURN ON RATE BASE	6.79%	6.79%	6.79%	6.79%	6.79%	6.79%	6.79%	6.79%	6.79%	6.79%
PRESENT O&M EXP	85,733,514	69,338	9,622,527	3,720,438	203,037	5,458	60,804,955	12,384,861	170,899	3,177,117
INCR IN 903-CUST ACCT & COLL FACTC	217,946	88	20,769	12,165	1,436	13	183,554	12,280	805	7,374
TOT OPERATION & MAINT EXP	85,951,460	69,426	9,643,297	3,732,603	204,473	5,472	60,988,509	12,397,142	171,704	3,184,491
DEPRECIATION & AMORTIZATION EXP	43,618,367	36,563	4,947,105	1,803,624	118,284	2,997	31,694,871	6,003,504	39,302	1,538,383
SO2 ALLOWANCE	1	0	0	0	0	0	0	0	0	0
NON-REVENUE TAXES OTHER THAN INC	11,415,708	9,239	1,300,959	479,384	29,559	765	8,255,095	1,546,269	11,904	408,611
REVENUE RELATED TAXES ARK	0	0	0	0	0	0	0	0	0	0
REVENUE RELATED TAXES LA	0	0	0	0	0	0	0	0	0	0
REVENUE RELATED TAXES TX	4,129,943	3,010	470,080	146,868	5,905	399	3,493,852	689,394	4,614	270,009
TOTAL TAXES OTHER THAN INCOME	15,545,651	12,248	1,771,039	626,253	35,463	1,164	11,748,947	2,235,663	16,518	678,620
REV RELATED TAX ON REVENUE DEFCIENCY	986,520	398	94,011	55,064	6,501	59	830,845	55,587	3,646	33,377
FED INCOME TAX LIABILITY	7,458,685	5,850	851,988	312,542	18,902	498	5,336,705	953,740	6,942	258,236
TOTAL OPERATING EXPENSES	153,560,684	124,485	17,307,439	6,530,085	383,624	10,190	110,599,878	21,645,635	238,112	5,693,106
COST OF SERVICE	205,286,099	165,598	23,147,990	8,652,020	514,955	13,612	148,537,798	28,805,477	285,963	7,600,606
TOTAL PROPOSED CREDITS	(33,013,458)	(19,616)	(3,678,284)	(1,346,188)	(39,848)	(1,927)	(24,120,664)	(4,834,257)	(22,494)	(1,404,493)
BASE REVENUE REQUIREMENT	**172,272,641**	**145,983**	**19,469,706**	**7,305,832**	**475,107**	**11,685**	**124,417,134**	**23,971,220**	**263,469**	**6,196,112**

PUBLIC UTILITY COMMISSION OF TEXAS
SOUTHWESTERN ELECTRIC POWER COMPANY
PUC DOCKET NO. 51415
PFD CLASS MODEL SUMMARY
FOR TEST YEAR JUNE 30, 2020

LLP TRAN	OILFIELD PRI	METAL MELTING PRI	METAL MELTING TRANS	METAL MELTING SEC	OILFIELD SEC	PUMPING SERVICE	MUNICIPAL SERVICE	MUNICIPAL LIGHTING	PUBLIC HIGHWAY	PRIVATE AREA LIGHTING	CUST-OWNED LIGHTING	TOTAL
93,058,024	53,016,721	6,467,541	5,902,818	735,800	4,561,234	10,310,226	6,271,826	10,778,186	392,491	18,950,263	1,494,930	1,786,562,748
6,318,640	3,599,835	439,146	400,801	49,961	309,708	700,064	425,857	731,839	26,650	1,286,723	101,506	121,307,611
6.79%	6.79%	6.79%	6.79%	6.79%	6.79%	6.79%	6.79%	6.79%	6.79%	6.79%	6.79%	6.79%
11,378,422	6,474,063	815,817	745,991	81,324	493,053	1,195,292	745,067	907,436	35,619	1,819,455	175,478	200,759,163
40,150	12,957	1,875	44	282	2,575	1,778	(263)	1,923	351	3,613	543	522,260
11,418,572	6,487,021	817,692	746,035	81,606	495,628	1,197,070	744,804	909,359	35,971	1,823,068	176,022	201,281,423
5,154,647	3,007,261	377,988	328,323	45,931	254,608	601,634	368,021	674,108	23,373	1,201,754	88,744	101,929,392
0	0	0	0	0	0	0	0	0	0	0	0	1
1,342,528	787,288	97,053	85,539	11,517	66,781	153,247	94,413	165,013	6,014	296,089	22,651	26,585,626
0	0	0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0	0	0
19,148	197,437	66,314	75,628	4,221	2,584	59,928	49,162	73,877	1,512	111,698	10,199	9,885,781
1,361,676	984,725	163,366	161,167	15,738	69,365	213,176	143,575	238,889	7,526	407,787	32,851	36,471,407
181,735	58,651	8,489	198	1,277	11,657	8,050	(1,192)	8,704	1,590	16,355	2,460	2,363,982
796,535	468,832	59,225	50,027	7,179	42,859	93,918	59,629	108,856	3,926	190,550	14,078	17,099,702
18,913,165	11,006,489	1,426,760	1,285,749	151,731	874,118	2,113,848	1,314,837	1,939,917	72,387	3,639,515	314,154	359,145,907
25,231,805	14,606,325	1,865,906	1,686,550	201,692	1,183,825	2,813,912	1,740,694	2,671,756	99,037	4,926,237	415,660	480,453,518
(4,856,887)	(2,358,552)	(239,545)	(306,561)	(16,495)	(193,837)	(402,439)	(264,000)	(224,128)	(8,785)	(411,026)	(46,758)	(77,810,240)
20,374,918	**12,247,773**	**1,626,361**	**1,379,990**	**185,197**	**989,989**	**2,411,473**	**1,476,695**	**2,447,628**	**90,252**	**4,515,211**	**368,902**	**402,643,278**

PUBLIC UTILITY COMMISSION OF TEXAS
SOUTHWESTERN ELECTRIC POWER COMPANY
PUC DOCKET NO. 51415
PFD TCRF BASELINES
FOR TEST YEAR JUNE 30, 2020

DESCRIPTION	TCRF BASELINE	RESIDENTIAL BASIC	RESIDENTIAL DG	GS W/ DEMAND	GS WO/ DEMAND	COTTON GIN	GS DG	LIGHT & POWER SEC	LIGHT & POWER PRI	LIGHT & POWER DG	LLP PRI
TIC	487,591,029	205,962,749	111,753	21,938,119	7,060,969	128,601	11,163	152,470,678	31,266,158	130,684	9,268,154
ROR	6.79%	6.79%	6.79%	6.79%	6.79%	6.79%	6.79%	6.79%	6.79%	6.79%	6.79%
RTIC	33,107,431	13,984,871	7,588	1,489,598	479,440	8,732	758	10,352,759	2,122,972	8,873	629,308
TDEPR	18,861,569	7,967,293	4,323	848,636	273,141	4,975	432	5,898,050	1,209,474	5,055	358,522
TFIT	5,130,407	2,166,109	1,175	231,085	74,378	871	118	1,606,050	329,340	1,376	97,626
TOT	6,095,885	2,574,917	1,397	274,281	88,280	1,590	140	1,906,260	390,904	1,634	115,875
TCRED	(70,834,945)	(29,929,943)	(16,240)	(3,183,747)	(1,024,716)	(26,750)	(1,620)	(22,127,153)	(4,537,470)	(18,965)	(1,345,031)
revreqt	(7,660,103)	(3,236,753)	(1,756)	(344,388)	(110,843)	(2,520)	(175)	(2,393,504)	(490,822)	(2,052)	(145,493)
ATC	67,409,237	28,474,256	15,450	3,032,935	976,176	17,779	1,543	21,079,001	4,322,532	18,067	1,281,318
ALLOC		100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
ClassALLOC		42.24%	0.02%	4.50%	1.45%	0.03%	0.00%	31.27%	6.41%	0.03%	1.90%
RR	**59,749,134**	**25,237,502**	**13,694**	**2,688,547**	**865,333**	**15,259**	**1,368**	**18,685,498**	**3,831,710**	**16,015**	**1,135,825**
BD		2,163,595,580	2,013,476	205,483,534	66,333,658	5,234,123	114,497	6,522,773	1,370,803	8,452	358,160
BD BASIS		kWh	kWh	kWh	kWh	kWh	kWh	kW	kW	kW	kW

PUBLIC UTILITY COMMISSION OF TEXAS
SOUTHWESTERN ELECTRIC POWER COMPANY
PUC DOCKET NO. 51415
PFD TCRF BASELINES
FOR TEST YEAR JUNE 30, 2020

Schedule B
Page 6 of 8

LLP TRAN	OILFIELD PRI	METAL MELTING PRI	METAL MELTING TRANS	METAL MELTING SEC	OILFIELD SEC	PUMPING SERVICE	MUNICIPAL SERVICE	MUNICIPAL LIGHTING	PUBLIC HIGHWAY	PRIVATE AREA LIGHTING	CUST-OWNED LIGHTING	TOTAL
32,360,709	14,983,459	1,467,947	2,041,182	80,097	1,044,089	2,438,406	1,486,875	1,056,355	20,673	1,991,867	270,340	487,591,029
6.79%	6.79%	6.79%	6.79%	6.79%	6.79%	6.79%	6.79%	6.79%	6.79%	6.79%	6.79%	6.79%
2,197,292	1,017,377	99,674	138,596	5,439	70,894	165,568	100,959	71,726	1,404	135,248	18,356	33,107,431
1,251,815	579,608	56,785	78,959	3,098	40,389	94,325	57,517	40,863	800	77,052	10,458	18,861,569
340,857	157,828	15,462	21,500	844	9,062	25,869	15,774	11,208	84	20,950	2,843	5,130,407
404,589	187,330	18,353	25,520	1,001	12,983	30,493	18,594	13,210	254	24,902	3,380	6,095,885
(4,696,315)	(2,174,459)	(213,034)	(296,225)	(11,624)	(178,056)	(351,732)	(214,477)	(152,375)	(6,273)	(289,453)	(39,285)	(70,834,945)
(508,017)	(235,213)	(23,045)	(32,043)	(1,258)	(18,397)	(38,088)	(23,225)	(16,499)	(463)	(31,301)	(4,248)	(7,660,103)
4,473,853	2,071,456	202,943	282,193	11,073	144,345	337,109	205,560	146,041	2,858	275,375	37,374	67,409,237
100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	
6.64%	3.07%	0.30%	0.42%	0.02%	0.21%	0.50%	0.31%	0.22%	0.00%	0.41%	0.06%	100%
3,965,836	**1,836,244**	**179,899**	**250,149**	**9,816**	**125,948**	**299,021**	**182,335**	**129,541**	**2,395**	**244,073**	**33,126**	**59,749,134**
1,433,918	765,088	194,231	220,660	24,392	40,837	60,026,735	26,943,781	26,004,489	1,070,584	49,398,122	6,704,408	
kW	kW	kW	kW	kW	kW	kWh	kWh	kWh	kWh	kWh	kWh	

PUBLIC UTILITY COMMISSION OF TEXAS
SOUTHWESTERN ELECTRIC POWER COMPANY
PUC DOCKET NO. 51415
PFD DCRF BASELINES
FOR TEST YEAR JUNE 30, 2020

DESCRIPTION	DCRF BASELINE	RESIDENTIAL BASIC	RESIDENTIAL DG	GS W/ DEMAND	GS WO/ DEMAND	COTTON GIN	GS DG	LIGHT & POWER SEC	LIGHT & POWER PRI	LIGHT & POWER DG	LLP PRI
DIC_{RC}	411,184,963	185,511,173	288,996	24,256,526	11,132,747	1,547,765	19,802	129,122,916	16,476,754	274,234	1,613,289
ROR_{AT}	6.79%	6.79%	6.79%	6.79%	6.79%	6.79%	6.79%	6.79%	6.79%	6.79%	6.79%
$DEPR_{RC}$	24,342,308	10,964,970	17,117	1,436,387	658,121	58,388	1,175	7,664,097	983,494	16,118	95,408
FIT_{RC}	4,207,614	1,898,758	2,966	248,200	113,827	11,328	204	1,326,484	169,317	2,747	16,374
OT_{RC}	5,442,530	2,458,138	3,832	321,841	147,691	13,000	263	1,715,051	218,808	3,617	21,355
$ALLOC_{CLASS}$		45.13%	0.07%	5.90%	2.71%	0.34%	0.00%	31.44%	4.01%	0.07%	0.39%
$DISTREV_{RC}$	61,911,911	27,918,075	43,538	3,653,446	1,675,552	187,809	2,986	19,473,078	2,490,390	41,102	242,680
$BD_{RC\text{-}CLASS}$		2,163,595,580	2,013,476	205,483,534	66,333,658	5,234,123	114,497	6,522,773	1,370,803	8,452	358,160
$BD_{RC\text{-}CLASS}$ BASIS		kWh	kWh	kWh	kWh	kWh	kWh	kW	kW	kW	kW

PUBLIC UTILITY COMMISSION OF TEXAS
SOUTHWESTERN ELECTRIC POWER COMPANY
PUC DOCKET NO. 51415
PFD DCRF BASELINES
FOR TEST YEAR JUNE 30, 2020

LLP TRAN	OILFIELD PRI	METAL MELTING PRI	METAL MELTING TRANS	METAL MELTING SEC	OILFIELD SEC	PUMPING SERVICE	MUNICIPAL SERVICE	MUNICIPAL LIGHTING	PUBLIC HIGHWAY	PRIVATE AREA LIGHTING	CUST-OWNED LIGHTING	TOTAL
91,751	9,887,949	2,207,512	15,772	512,979	1,142,741	3,324,019	1,991,028	7,760,859	313,483	12,982,668	709,999	411,184,963
6.79%	6.79%	6.79%	6.79%	6.79%	6.79%	6.79%	6.79%	6.79%	6.79%	6.79%	6.79%	6.79%
4,991	589,309	131,735	872	30,466	55,093	198,891	118,657	466,740	7,637	800,572	42,069	24,342,308
739	101,321	22,661	133	5,275	10,110	34,377	20,512	80,336	1,589	133,070	7,287	4,207,614
1,146	131,209	29,306	199	6,815	12,296	44,525	26,645	103,959	1,688	171,732	9,414	5,442,530
0.02%	2.41%	0.54%	0.00%	0.12%	0.27%	0.81%	0.49%	1.89%	0.07%	3.15%	0.17%	100.00%
13,106	1,493,230	333,592	2,276	77,387	155,091	503,494	301,004	1,177,997	32,200	1,986,897	106,980	61,911,911
1,433,918	765,088	194,231	220,660	24,392	40,837	60,026,735	26,943,781	26,004,489	1,070,584	49,398,122	6,704,408	
kW	kW	kW	kW	kW	kW	kWh	kWh	kWh	kWh	kWh	kWh	

PUBLIC UTILITY COMMISSION OF TEXAS
SOUTHWESTERN ELECTRIC POWER COMPANY
PUC DOCKET NO. 51415
PFD REVENUE DISTRIBUTION
FOR TEST YEAR JUNE 30, 2020

Schedule C
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Class	Present Base Revenue	Present Base + TCRF + DCRF Revenue	Cost-Based Electric Revenue	PFD Cost Based Gross Bill Change	Cost-Based % Change	PFD Target Gross Bill Change	PFD Target Gross % Change	PFD Target Net Bill Change	PFD Target Net % Change	PFD Revenue Requirements
Residential	**147,077,995**	**153,227,969**	**172,418,624**	**25,340,629**	**17.23%**	**25,340,629**	**17.23%**	**19,190,655**	**12.52%**	**172,418,624**
General Service w/ Demand	16,998,369	17,638,468	19,481,392	2,483,022	14.61%	2,508,967	14.76%	1,868,869	10.60%	19,507,337
General Service w/o Demand	5,669,225	5,875,817	7,305,832	1,636,607	28.87%	1,646,337	29.04%	1,439,745	24.50%	7,315,562
Lighting & Power Sec	100,037,248	104,243,548	124,680,603	24,643,355	24.63%	24,809,402	24.80%	20,603,103	19.76%	124,846,650
Lighting & Power Pri	23,827,679	24,896,460	23,971,220	143,541	0.60%	175,465	0.74%	(893,316)	-3.59%	24,003,144
Cotton Gin	231,688	249,858	475,107	243,419	105.06%	100,228	43.26%	82,058	32.84%	331,916
Large Lighting & Power Pri	5,298,104	5,538,446	6,196,112	898,008	16.95%	906,260	17.11%	665,918	12.02%	6,204,364
Large Lighting & Power Tran	22,387,847	23,470,723	20,374,918	(2,012,929)	-8.99%	(1,985,795)	-8.87%	(3,068,670)	-13.07%	20,402,053
Metal Melting-Sec	143,749	151,026	185,197	41,448	28.83%	41,695	29.01%	34,418	22.79%	185,444
Metal Melting-Pri	1,402,858	1,496,310	1,626,361	223,503	15.93%	225,669	16.09%	132,217	8.84%	1,628,527
Metal Melting-Tran	1,498,929	1,672,408	1,379,990	(118,939)	-7.93%	(117,102)	-7.81%	(290,581)	-17.37%	1,381,827
Oilfield Pri	10,636,387	11,134,950	12,247,773	1,611,386	15.15%	1,627,698	15.30%	1,129,134	10.14%	12,264,084
Oilfield Sec	588,848	591,392	989,989	401,140	68.12%	254,736	43.26%	252,193	42.64%	843,584
Total Commercial & Industrial	**188,720,933**	**196,959,406**	**218,914,493**	**30,193,561**	**16.00%**	**30,193,561**	**16.00%**	**21,955,087**	**11.15%**	**218,914,493**
Municipal Pumping	2,279,333	2,390,468	2,411,473	132,140	5.80%	150,041	6.58%	38,905	1.63%	2,429,373
Municipal Service	1,650,219	1,701,604	1,476,695	(173,524)	-10.52%	(162,563)	-9.85%	(213,948)	-12.57%	1,487,656
Municipal Lighting	2,267,085	2,351,444	2,447,628	180,543	7.96%	198,712	8.77%	114,353	4.86%	2,465,797
Public Street & Hwy Lighting	30,170	33,447	90,252	60,082	199.14%	13,051	43.26%	9,775	29.22%	43,221
Total Muni & Muni Lighting	**6,226,806**	**6,476,962**	**6,426,047**	**199,241**	**3.20%**	**199,241**	**3.20%**	**(250,156)**	**-3.86%**	**6,226,806**
Private, Outdoor, Area Lighting	4,150,616	4,307,444	4,515,211	364,595	8.78%	364,595	8.78%	207,767	4.82%	4,515,211
Customer-Owned Lighting	293,022	324,093	368,902	75,880	25.90%	75,880	25.90%	44,809	13.83%	368,902
Total Lighting	**4,443,639**	**4,631,537**	**4,884,113**	**440,474**	**9.91%**	**440,474**	**9.91%**	**252,576**	**5.45%**	**4,884,113**
Total Firm Retail	**346,469,372**	**361,295,874**	**402,643,278**	**56,173,905**	**16.21%**	**56,173,905**	**16.21%**	**41,347,404**	**11.44%**	**402,643,278**

PUBLIC UTILITY COMMISSION OF TEXAS
SOUTHWESTERN ELECTRIC POWER COMPANY
PUC DOCKET NO. 51415
PFD RATES SUMMARY
FOR TEST YEAR JUNE 30, 2020

RATE SHEET	RATE CLASS	TYPE OF RATE	Current Rates	SWEPCO Proposed Rates	Staff Proposed Rates	
IV-1	Residential	Customer Charge	$ 8.00	$ 10.00	$ 9.44	per customer
		Net Metering Admin Fee	$ 8.00	$ 10.00	$ 9.44	per customer
		kWh Charge (on peak)	$ 0.072266	$ 0.092448	$ 0.084717	per kWh
		Block 1 kWh Charge	$ 0.053589	$ 0.068555	$ 0.062835	per kWh
		Block 2 kWh Charge	$ 0.043789	$ 0.056855	$ 0.051354	per kWh
IV-2	General Service W/D	Customer Charges	$ 11.59	$ 15.00	$ 13.30	per customer
		Net Metering Admin Fee	$ 8.00	$ 10.00	$ 9.44	
		Block 2 kW Charge	$ 4.87	$ 2.95	$ 5.59	per kW
		kWh Charge	$ 0.061302	$ 0.075419	$ 0.070526	per kWh
IV-2	General Service Wo/D	Customer Charges	$ 11.59	$ 15.00	$ 13.30	per customer
		kWh Charge	$ 0.061302	$ 0.089950	$ 0.082768	per kWh
IV-3	Lighting & Power Secondary	Block 2 kW Charge	$ 9.38	$12.48	$ 9.23	per kW
		kWh Charge	$ 0.016155	$ 0.022038	$ 0.015610	per kWh
	Lighting & Power Primary	Block 2 kW Charge	$ 9.16	$ 12.18	$ 9.23	per kW
		kWh Charge	$ 0.014904	$ 0.020470	$ 0.015610	per kWh
IV-4	Large Lighting & Power Primary	Block 2 kW Charge	$ 10.02	$ 13.32	$ 11.73	per kW
		kWh Charge	$ 0.010382	$ 0.013816	$ 0.012166	per kWh
IV-4	Large Lighting & Power Transmission	Block 2 kW Charge	$ 6.87	$ 7.93	$ 6.26	per kW
		kWh Charge	$ 0.010382	$ 0.012212	$ 0.010075	per kWh
Various		kVAR charge	$ 0.51	$ 0.66	$ 0.51	per kVAR
		Additional Transformer Cap	$ 1.60	$ 2.08	$ 1.86	per kVAR
IV-6	Metal Melting-Secondary	Block 2 kW Charge	$ 4.63	$ 6.16	$ 5.27	per kW
		kWh Charge	$ 0.015014	$ 0.019925	$ 0.020074	per kWh
	Metal Melting-Primary	Block 2 kW Charge	$ 4.54	$ 6.04	$ 5.33	per kW
		kWh Charge	$ 0.014613	$ 0.019422	$ 0.015868	per kWh
IV-7	Metal Melting-69kV	Block 2 kW Charge	$ 3.42	$ 4.55	$ 3.15	per kVA
		kWh Charge	$ 0.010211	$ 0.013569	$ 0.009425	per kWh
IV-8	Off Peak Rider	Customer Charge	$ 81.14	$ 107.90	$ 94.12	per customer
IV-13	Oilfield Service	Primary kW Charge	$ 7.93	$ 10.55	$ 9.14	per kW
		Primary kWh Charge	$ 0.01155	$ 0.015507	$ 0.013236	per kWh
		Secondary kW Charge	$ 8.29	$ 11.02	$ 11.88	per kW
		Secondary kWh Charge	$ 0.01209	$ 0.016109	$ 0.017226	per kWh
IV-14	Cotton Gin Service	Customer Charge	$ 29.21	$ 38.84	$ 41.85	per customer
		Per kWh (May-Oct)	$ 0.097105	$ 0.129129	$ 0.139113	per kWh
		Per kWh (Nov - Apr)	$ 0.050171	$ 0.066717	$ 0.061343	per kWh
IV-19	Municipal Pumping	kWh Charge	$ 0.036899	$ 0.041875	$ 0.039328	per kWh
IV-20	Municipal Service	kWh Charge	$ 0.058369	$ 0.066241	$ 0.052619	per kWh
IV-21/22	Recreational Lighting and	Customer Charge	$ 7.35	$ 10.01	$ 9.25	per customer
	Customer-Supplied Lighting	kWh Charge	$ 0.040229	$ 0.055472	$ 0.050752	per kWh

PUBLIC UTILITY COMMISSION OF TEXAS
SOUTHWESTERN ELECTRIC POWER COMPANY
PUC DOCKET NO. 51415
PFD RATES SUMMARY
FOR TEST YEAR JUNE 30, 2020

IV-23	MUNICIPAL STREET LIGHTING								
IV-24	Rate Code 521								
IV-25	175W Mercury Vapor	Wood/Overhead	$	8.71	$	6.84	$	9.00	per fixture
IV-31	400W Mercury Vapor	Wood/Overhead	$	14.82	$	11.63	$	15.32	
	400W Mercury Vapor	Non-Wood/Overhead	$	16.44	$	12.91	$	16.99	
	400W Mercury Vapor	Base-Mounted/Overhead	$	18.24	$	14.32	$	18.85	
	400W Mercury Vapor	Base-Mounted/Underground	$	20.44	$	16.05	$	21.13	
	70W High Pressure Sodium	Wood/Overhead	$	10.51	$	8.25	$	10.86	
	70W High Pressure Sodium	Non-Wood/Overhead	$	12.13	$	9.52	$	12.54	
	70W High Pressure Sodium	Base-Mounted/Overhead	$	13.92	$	10.93	$	14.39	
	70W High Pressure Sodium	Non-Wood/Underground	$	14.34	$	11.26	$	14.82	
	70W High Pressure Sodium	Base-Mounted/Underground	$	16.12	$	12.65	$	16.66	
	150W High Pressure Sodium	Wood/Overhead	$	19.21	$	15.08	$	19.85	
	150W High Pressure Sodium	Non-Wood/Overhead	$	20.84	$	16.36	$	21.54	
	150W High Pressure Sodium	Base-Mounted/Overhead	$	22.65	$	17.78	$	23.41	
	150W High Pressure Sodium	Non-Wood/Underground	$	23.05	$	18.09	$	23.82	
	150W High Pressure Sodium	Base-Mounted/Underground	$	24.84	$	19.50	$	25.67	
	250W High Pressure Sodium	Wood/Overhead	$	22.31	$	17.51	$	23.06	
	250W High Pressure Sodium	Non-Wood/Overhead	$	23.94	$	18.79	$	24.74	
	250W High Pressure Sodium	Base-Mounted/Overhead	$	25.72	$	20.19	$	26.58	
	250W High Pressure Sodium	Non-Wood/Underground	$	26.14	$	20.52	$	27.02	
	250W High Pressure Sodium	Base-Mounted/Underground	$	27.93	$	21.93	$	28.87	
	300W High Pressure Sodium	Wood/Overhead	$	32.58	$	25.58	$	33.67	
	300W High Pressure Sodium	Non-Wood/Overhead	$	34.21	$	26.85	$	35.36	
	300W High Pressure Sodium	Base-Mounted/Overhead	$	36.00	$	28.26	$	37.21	
	300W High Pressure Sodium	Non-Wood/Underground	$	36.41	$	28.58	$	37.63	
	300W High Pressure Sodium	Base-Mounted/Underground	$	38.20	$	29.99	$	39.48	
	500W High Pressure Sodium	Wood/Overhead	$	36.65	$	28.77	$	37.88	
	500W High Pressure Sodium	Non-Wood/Overhead	$	38.28	$	30.05	$	39.56	
	500W High Pressure Sodium	Base-Mounted/Overhead	$	40.07	$	31.45	$	41.41	
	500W High Pressure Sodium	Non-Wood/Underground	$	40.48	$	31.78	$	41.84	
	500W High Pressure Sodium	Base-Mounted/Underground	$	42.26	$	33.17	$	43.68	
	35W Low Pressure Sodium	Wood/Overhead	$	10.67	$	8.38	$	11.03	
	55W Low Pressure Sodium	Wood/Overhead	$	10.67	$	8.38	$	11.03	
	55W Low Pressure Sodium	Non-Wood/Overhead	$	12.29	$	9.65	$	12.70	
	55W Low Pressure Sodium	Base-Mounted/Overhead	$	14.09	$	11.06	$	14.56	
	90W Low Pressure Sodium	Wood/Overhead	$	20.36	$	15.98	$	21.04	
	90W Low Pressure Sodium	Non-Wood/Overhead	$	21.99	$	17.26	$	22.73	
	90W Low Pressure Sodium	Base-Mounted/Overhead	$	23.79	$	18.68	$	24.59	
	90W Low Pressure Sodium	Non-Wood/Underground	$	24.19	$	18.99	$	25.00	
	90W Low Pressure Sodium	Base-Mounted/Underground	$	25.99	$	20.40	$	26.86	
	180W Low Pressure Sodium	Wood/Overhead	$	34.61	$	27.17	$	35.77	
	180W Low Pressure Sodium	Non-Wood/Overhead	$	36.24	$	28.45	$	37.46	
	180W Low Pressure Sodium	Base-Mounted/Overhead	$	38.04	$	29.86	$	39.32	
	180W Low Pressure Sodium	Non-Wood/Underground	$	38.44	$	30.18	$	39.73	
	180W Low Pressure Sodium	Base-Mounted/Underground	$	40.24	$	31.59	$	41.59	
	Rate Code 529-(CLOSED)								
	75W Mercury Vapor		$	4.18	$	5.27	$	4.32	per fixture
	100W Mercury Vapor		$	4.61	$	5.81	$	4.76	
	400W Mercury Vapor		$	9.39	$	11.83	$	9.71	
	Rate Code 528 (OPEN)								
	100W Mercury Vapor		$	2.01	$	2.53	$	2.08	per fixture
	175W Mercury Vapor		$	2.75	$	3.46	$	2.84	
	250W Mercury Vapor		$	3.80	$	4.79	$	3.93	
	150W Mercury Vapor		$	5.60	$	7.06	$	5.79	
	400W Metal Halide		$	4.96	$	6.25	$	5.13	
	400W Metal Halide		$	6.45	$	8.13	$	6.67	
	1000W Metal Halide		$	15.00	$	18.90	$	15.50	
	70W High Pressure Sodium		$	2.11	$	2.66	$	2.18	
	100W High Pressure Sodium		$	2.75	$	3.46	$	2.84	
	150W High Pressure Sodium		$	3.07	$	3.87	$	3.17	
	250W High Pressure Sodium		$	4.54	$	5.72	$	4.69	
	400W High Pressure Sodium		$	6.45	$	8.13	$	6.67	
	1000W High Pressure Sodium		$	14.90	$	18.77	$	15.40	

PUBLIC UTILITY COMMISSION OF TEXAS
SOUTHWESTERN ELECTRIC POWER COMPANY
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PFD RATES SUMMARY
FOR TEST YEAR JUNE 30, 2020

	Rate Code 538 (CLOSED)							
	6,000L Incandescent		$	8.71	$	10.97	$ 9.00	per fixture
	16000L Mercury Vapor Wood		$	9.05	$	11.40	$ 9.35	
	Rate Code 535 (OPEN)							
	100W Mercury Vapor		$	2.53	$	3.19	$ 2.61	
	175W Mercury Vapor		$	3.49	$	4.40	$ 3.61	
	250W Mercury Vapor		$	4.80	$	6.05	$ 4.96	
	400W Mercury Vapor		$	7.06	$	8.89	$ 7.30	
	1000W Mercury Vapor		$	15.83	$	19.94	$ 16.36	
	150W Metal Halide		$	6.26	$	7.89	$ 6.47	
	400W Metal Halide		$	8.14	$	10.26	$ 8.41	
	1000W Metal Halide		$	18.92	$	23.84	$ 19.55	
	70W High Pressure Sodium		$	2.66	$	3.35	$ 2.75	
	100W High Pressure Sodium		$	3.48	$	4.38	$ 3.60	
	150W High Pressure Sodium		$	3.87	$	4.88	$ 4.00	
	250W High Pressure Sodium		$	5.73	$	7.22	$ 5.92	
	400W High Pressure Sodium		$	8.14	$	10.26	$ 8.41	
	1000W High Pressure Sodium		$	18.75	$	23.62	$ 19.38	
IV-26	PUBLIC STREET & HIGHWAY LIGHTING							
IV-27	Rate Codes 534,539,739 (OPEN)							
	100W Mercury Vapor		$	1.38	$	1.57	$ 2.15	per fixture
	175W Mercury Vapor		$	2.12	$	2.41	$ 3.30	
	250W Mercury Vapor		$	3.20	$	3.63	$ 4.98	
	400W Mercury Vapor		$	5.01	$	5.69	$ 7.79	
	1000W Mercury Vapor		$	11.73	$	13.31	$ 18.25	
	400W Metal Halide		$	5.00	$	5.67	$ 7.78	per fixture
	1000W Metal Halide		$	12.01	$	13.63	$ 18.68	
	70W High Pressure Sodium		$	1.08	$	1.23	$ 1.68	
	100W High Pressure Sodium		$	1.60	$	1.82	$ 2.49	
	150W High Pressure Sodium		$	1.92	$	2.18	$ 2.99	
	250W High Pressure Sodium		$	3.41	$	3.87	$ 5.30	
	400W High Pressure Sodium		$	5.34	$	6.06	$ 8.31	
	1000W High Pressure Sodium		$	12.46	$	14.14	$ 19.38	
IV-28	PRIVATE, OUTDOOR & AREA LIGHTING							
IV-29	Private 2500L	Incandescent	$	4.54	$	6.15	$ 5.27	per fixture
IV-30	Private 7700	Mercury Vapor	$	6.05	$	8.19	$ 7.02	
IV-32	Private 7700 w/Pole	Mercury Vapor	$	6.05	$	8.19	$ 7.02	
IV-33	Area 100W	Mercury Vapor	$	5.42	$	7.34	$ 6.30	per fixture
	Area 175W	Mercury Vapor	$	6.05	$	8.19	$ 7.03	
	Area 250W	Mercury Vapor	$	6.84	$	9.26	$ 7.95	
	Area 400W	Mercury Vapor	$	8.17	$	11.06	$ 9.50	
	Area 1000W	Mercury Vapor	$	13.43	$	18.18	$ 15.60	
	Area 400W	Metal Halide	$	4.79	$	6.48	$ 5.57	
	Area 1000W	Metal Halide	$	11.14	$	15.08	$ 12.94	
	Area 100W	High Pressure Sodium	$	2.05	$	2.78	$ 2.38	
	Area 250W	High Pressure Sodium	$	3.38	$	4.58	$ 3.93	
	Area 400W	High Pressure Sodium	$	4.79	$	6.48	$ 5.56	
	Area 1000W	High Pressure Sodium	$	11.07	$	14.99	$ 12.85	
	Outdoor 175W	Mercury Vapor	$	8.14	$	11.02	$ 9.46	per fixture
	Outdoor 400W	Mercury Vapor	$	11.37	$	15.39	$ 13.20	
	Outdoor 70W	High Pressure Sodium	$	8.60	$	11.64	$ 9.99	
	Outdoor 150W	High Pressure Sodium	$	12.00	$	16.24	$ 13.93	
	Floodlighting 250W	Metal Halide	$	9.26	$	12.53	$ 10.75	per fixture
	Floodlighting 400W	Metal Halide	$	10.53	$	14.25	$ 12.23	
	Floodlighting 1000W	Metal Halide	$	18.97	$	25.68	$ 22.03	
	Floodlighting 150W	High Pressure Sodium		$7.98		$10.80	$ 9.27	
	Floodlighting 250W	High Pressure Sodium		$9.16		$12.40	$ 10.64	
	Floodlighting 400W	High Pressure Sodium		$10.37		$14.04	$ 12.04	
	Floodlighting 1000W	High Pressure Sodium		$18.82		$25.48	$ 21.85	

PUBLIC UTILITY COMMISSION OF TEXAS
SOUTHWESTERN ELECTRIC POWER COMPANY
PUC DOCKET NO. 51415
PFD RATE CASE EXPENSES
FOR TEST YEAR JUNE 30, 2020

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RESIDENTIAL	$	0.000244	$/kWh
TOTAL COMMERCIAL & SMALL INDUSTRIAL C	$	0.000174	$/kWh
TOTAL MUNICIPAL CLASS	$	0.000117	$/kWh
TOTAL LIGHTING CLASS	$	0.000249	$/kWh
TOTAL INDUSTRIAL CLASS		0.306%	% of Base Revenues

PUBLIC UTILITY COMMISSION OF TEXAS
SOUTHWESTERN ELECTRIC POWER COMPANY
PUC DOCKET NO. 51415
PFD RATE CASE EXPENSES
FOR TEST YEAR JUNE 30, 2020

Docket No. 51415 REC Costs	$ 1,281,301
TX Retail Allocation (ENERGY)	36.96%
TX Retail Allocated REC Costs	$ 473,593

	Class ENERGY	REC Costs in Base Rates	kWh at Meter	REC Opt Out Credit/kWh
Residential	31.72%	$ 150,230.47		
Commercial	45.13%	$ 213,749.07	3,105,486,129	$ 0.000069
Industrial	20.65%	$ 97,810.06	1,481,924,742	$ 0.000066
Municipal	1.67%	$ 7,911.46		
Lighting	0.82%	$ 3,891.89		

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STYLE/CASE: SOUTHWESTERN ELECTRIC POWER COMPANY

SOAH DOCKET NUMBER: 473-21-0538

REFERRING AGENCY CASE: 51415

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TEXAS INDUSTRIAL ENERGY CONSUMERS

September 26, 2022

Stephen Journey Commission Counsel
Public Utility Commission of Texas
1701 N. Congress 7th Floor
Austin, Texas 78701

VIA EFILE TEXAS

Re: SOAH Docket No. 473-22-1074; PUC Docket No. 52487; *Application of Entergy Texas, Inc. to Amend Its Certificate of Convenience and Necessity to Construct Orange County Advanced Power Station*

Enclosed is the Proposal for Decision (PFD) in the above-referenced case. By copy of this letter, the parties to this proceeding are being served with the PFD.

Please place this case on an open meeting agenda for the Commissioners' consideration. Please notify the undersigned Administrative Law Judges and the parties of the open meeting date, as well as the deadlines for filing exceptions to the PFD, replies to the exceptions, and requests for oral argument.

Christiaan Siano,
Administrative Law Judge

Megan Johnson,
Administrative Law Judge

Enclosure
xc: All Parties of Record

SOAH Docket No. 473-22-1074 **Suffix: PUC**
PUC Docket No. 52487

Before the
State Office of Administrative Hearings

APPLICATION OF ENTERGY TEXAS, INC. TO AMEND ITS CERTIFICATE OF CONVENEINCE AND NECESSITY TO CONSTRUCT ORANGE COUNTY ADVANCED POWER STATION

TABLE OF CONTENTS

LIST OF ACRONYMS AND ABBREVIATIONS

ALJ	Administrative Law Judge
BP21	2021 Business Plan
BP22	2022 Business Plan
CCCT	Combined-Cycle Gas Combustion Turbine
CCGT	Combined-Cycle Gas Turbine
CCN	Certificate of Convenience and Necessity
CMP	Coastal Management Program
CoL	Conclusion of Law
Commission or PUC	The Public Utility Commission of Texas
CONE	Cost of New Entry
CT	Combustion Turbine
EIA	Energy Information Administration
EPA	United States Environmental Protection Agency
EPC	Engineering, Procurement, and Construction
EPG	Entergy's Enterprise Planning Group
ETI or Company	Entergy Texas, Inc.
FoF	Finding of Fact
IM	Independent Monitor

LCSF	Liberty County Solar Facility
LNTP	Limited Notice to Proceed
LRZ	Load Resource Zone
MCPS	Montgomery County Power Station
MISO	Midcontinent Independent System Operator
MMBtu	Millions of British Thermal Units
MW	Megawatt
NPV	Net Present Value
NOx	Nitrogen Oxide
NYMEX	New York Mercantile Exchange
OCAPS	Orange County Advanced Power Station
O&M	Operations & Maintenance
PFD	Proposal for Decision
PPA	Purchase Power Agreement
PRA	Planning Resource Auction
PURA	Public Utility Regulatory Act, Tex. Util. Code §§ 11.001 *et seq.*
RFP	Request for Proposals
TIEC	Texas Industrial Energy Consumers
VLR	Voltage and Local Reliability

SOAH Docket No. 473-22-1074 Suffix: PUC
PUC Docket No. 52487

Before the
State Office of Administrative Hearings

APPLICATION OF ENTERGY TEXAS, INC. TO AMEND ITS CERTIFICATE OF CONVENEINCE AND NECESSITY TO CONSTRUCT ORANGE COUNTY ADVANCED POWER STATION

PROPOSAL FOR DECISION

Entergy Texas, Inc. (ETI) filed an application with the Public Utility Commission of Texas (Commission) seeking to amend its certificate of convenience and necessity (CCN) for approval to construct, own, and operate the proposed 1,215-megawatt (MW) Orange County Advanced Power Station (OCAPS), at its existing Sabine Power Station site in Bridge City, Texas. OCAPS would be able to co-fire up to 30% hydrogen by volume upon commercial operation, and upgradeable to support 100% hydrogen operation in the future. The estimated total cost of construction and interconnection has increased from $1.19 billion at the filing of the application in September 2021, to $1.58 billion at the time of the hearing in June 2022. For reasons discussed in this Proposal for Decision (PFD), the Administrative Law Judges (ALJs) recommend approving the application without the hydrogen component and impose certain conditions, including a cost cap.

I. JURISDICTION, NOTICE, PROCEDURAL HISTORY

The Commission has jurisdiction and authority over this matter pursuant to the Public Utility Regulatory Act (PURA)[1] sections 14.001, 37.051(a), 37.053, 37.056, 37.058(d), and 39.452(j). The State Office of Administrative Hearings (SOAH) has jurisdiction, pursuant to Texas Government Code section 2003.049 and PURA section 14.053, over all matters relating to the conduct of a hearing in this matter.

The application was found administratively complete and notice sufficient.[2] The details of the provision of notice were not disputed and are addressed in the findings of fact and conclusions of law.

The Commission referred the matter to SOAH on December 13, 2021. Cities,[3] East Texas Electric Cooperative, Inc. (ETEC), Texas Industrial Energy Consumers (TIEC), Sierra Club, International Brotherhood of Electrical Workers, Local 2286 (IBEW 2286), and the Office of Public Utility Counsel (OPUC) intervened. ETI, staff of the Commission (Staff), TIEC, Sierra Club, and OPUC filed testimony. TIEC, Sierra Club, IBEW 2286, and ETEC filed statements of

[1] Public Utility Regulatory Act, Tex. Util. Code §§ 11.001-66.016 (PURA).

[2] Order No. 3 (Oct. 18, 2021).

[3] As used herein, Cities refers to the Cities of Anahuac, Beaumont, Bridge City, Cleveland, Dayton, Groves, Houston, Huntsville, Liberty, Montgomery, Navasota, Nederland, Oak Ridge North, Orange, Pine Forest, Pinehurst, Port Arthur, Port Neches, Roman Forest, Shenandoah, Silsbee, Sour Lake, Splendora, Vidor, West Orange, and Willis.

position. ETEC and Cities support the application, except that Cities oppose the hydrogen component, as does Staff, who takes no position on the application, but recommends conditions. IBEW 2286 expresses general concern about the proposed project. TIEC, Sierra Club and OPUC oppose the application.

The Commission issued a Preliminary Order (PO) listing the issues to be addressed in this proceeding.[4] The hearing on the merits, originally scheduled to begin April 28, 2022, was continued at ETI's request to June 29; it concluded on July 1, 2022. The evidentiary record closed on July 5, 2022. Parties filed initial briefs on July 18, 2022, and reply briefs on July 29, 2022. The record closed with the filing of reply briefs.

After the record close date, TIEC requested the opportunity to provide supplemental briefing on the impact of the energy-related provisions of the recently enacted Inflation Reduction Act (IRA), which became law on August 16, 2022. Given the time constraints, the request was denied. The ALJs recognize that the IRA could have a significant impact on key assumptions relating to the economics of the proposed project, including the increased penetration of renewable resources and the viability of hydrogen. Those potential impacts are noted where obvious, but without the benefit of further analysis, the impacts are not fully reflected in this PFD.

ETI designated certain information and documents as containing "Highly Sensitive Protected Material" (HSPM) pursuant to the Protective Order adopted

[4] Preliminary Order (Dec. 16, 2021).

in this case. Therefore, the ALJs closed the hearing to the public when a party indicated HSPM information needed to be discussed and opened the hearing after the discussions were complete. Some of this information has since been declassified by consent of ETI.

II. THE PROJECT

A. Description of OCAPS

OCAPS will be located in Bridge City, Texas, adjacent to ETI's existing generation plant at the Sabine Power Station.[5] The proposed OCAPS is a combined-cycle gas combustion turbine (CCCT) plant.[6] The turbines would be designed to co-fire up to 30% hydrogen.[7] OCAPS is expected to add 1,158 MW (summer rating) to ETI's generation portfolio with a heat rate of 6,226 British thermal units per kiloWatt hour (Btu/kWh).[8] OCAPS will be capable of providing a nominal output of 1,215 MW of generating capacity.[9] OCAPS will be constructed to use the existing gas storage capability at ETI's Spindletop gas storage facility.[10] If approved, the OCAPS project is expected to enter service by May of 2026.[11]

[5] ETI Ex. 8 (Ruiz Dir.) at 4-5; ETI Ex. 3A (Rainer Dir.) at 9.

[6] ETI Ex. 1 (Application) at 1; ETI Ex. 3A (Rainer Dir.) at 4, 8.

[7] ETI Ex. 3A (Rainer Dir.) at 8.

[8] ETI Ex. 1 (Application) at 1, n. 1; Cities Ex. 1 (O'Donnell Dir.) at 9, Att. 1 at 29 (citing ETI's Response to Cities 2-3).

[9] ETI Ex. 8 (Ruiz Dir.) at 4.

[10] ETI Ex. 3A (Rainer Dir.) at 4.

[11] ETI Ex. 3A (Rainer Dir.) at 9; ETI Ex. 1 (Application) at 2.

ETI's service territory is fully contained in the West of Atchafalaya Basin (WOTAB) planning region, which is considered a load pocket, but also includes portions of Southwest Louisiana.[12] ETI's Eastern Region, where OCAPS would be located, is the area from the Louisiana border on the east, the Gulf of Mexico on the South, ETI's Western Region on the west, and the Southwest Power Pool on the north.[13]

B. Construction Contract

OCAPS will be constructed under an engineering, procurement, and construction (EPC) contract by the EPC Consortium.[14] The price of OCAPS is determined by two cost categories: EPC agreement costs and non-EPC costs.[15]

EPC agreement costs include certain commodity costs and major equipment such as the turbines.[16] As explained by ETI witness Carlos Ruiz, many of the costs to construct OCAPS will be largely fixed at the time that ETI issues a limited notice to proceed (LNTP) to the EPC Consortium. However, EPC costs can be affected by change of scope, force majeure events, market escalation, delay in issuing a notice to proceed, craft attraction needs, or changes in law.[17] ETI chief executive officer Eliecer Viamontes testified that part of the risk of OCAPS is that there is no way of knowing what the price of the EPC agreement will

[12] ETI Ex. 4 (Weaver Dir.) at 26; ETI Ex. 5 (Kline Dir.) at 6, Exh. DK-2 at Bates 33 of 46.

[13] ETI Ex. 5 (Kline Dir.) at 6, Exh. DK-2 (Bates 8, 33).

[14] "EPC Consortium" consists of a number of contractors including Sargent & Lundy, The Industrial Company, and Mitsubishi Power Americas. ETI Ex. 8 (Ruiz Dir.) at 4.

[15] ETI Ex. 8 (Ruiz Dir.) at 17-19.

[16] Tr. at 193 (Ruiz Cross).

[17] ETI Ex. 8 (Ruiz Dir.) at 14.

ultimately be.[18] The EPC agreement price can be amended, or "trued-up," for escalation at the request of the EPC Contractor before LNTP issuance.[19] Part of that true-up will be based on risk of escalation that will impact procurement costs.[20] Mr. Viamontes further explained that by "true-up" ETI means "that the previous price that we received would no longer apply and we would seek from the EPC vendors an updated pricing for the project."[21] Thus, while the EPC costs can fluctuate, they are largely fixed when the LNTP is issued.

Nevertheless, the cost of the EPC agreement may change following the LNTP issuance for change orders, discovery of new facts, and force majeure events that could increase the final price.[22] Mr. Ruiz testified that force majeure events have already occurred and increased the cost of OCAPS, and some (like the war in Ukraine) are ongoing.[23]

[18] Tr. at 28 (Viamontes Cross).

[19] Tr. at 185-200 (Ruiz Cross); ETI Ex. 8A (Ruiz Dir.) (HSPM), Exh. CR-8 at Bates 52 of 2120 (Sec. 3.3).

[20] ETI Ex. 8A (Ruiz Dir.) (HSPM), Exh. CR-8 at Bates 1610 of 2120.

[21] Tr. at 28 (Viamontes Cross).

[22] Tr. at 195-97 (Ruiz Cross); ETI Ex. 8A (Ruiz Dir., Conf.), Exh. CR-8 at Bates 91 of 2120 (Section 33.2), Bates 92 of 2120 (Article 5.4), Bates 95 of 2120 (Section 37.7).

[23] Tr. at 239 (Ruiz Cross).

The non-EPC costs are not fixed.[24] Non-EPC costs include components such as other vendors and expenses, project management, allowance for funds used during construction (AFUDC), regulatory, transmission upgrades, and project contingency.[25]

As of ETI's third periodic report on market escalation, EPC costs comprised 71% of the total estimate, with non-EPC costs comprising the remaining 29%.[26]

C. Costs

Although initially expected to decline,[27] the estimated costs for the OCAPS project have increased dramatically over the course of this proceeding. In September 2021, when the application was filed, the estimated cost was \$1.19 billion, including the costs for the generation facilities, transmission upgrades, contingencies, and AFUDC.[28] However, market escalation in commodity, metal, and other relevant price indices brought the estimate to \$1.37 billion in April 2022,[29] and further to \$1.58 billion at the end of June 2022, based on issuing a

[24] ETI Ex. 8 (Ruiz Dir.) at 5, n.3.

[25] Tr. at 202-03 (Ruiz Cross); ETI Ex. 8 (Ruiz Dir.) at 18-19.

[26] Tr. at 201-03 (Ruiz Cross).

[27] ETI Ex. 8 (Ruiz Dir.) at 37 ("ETI and the EPC Consortium expect the currently elevated materials and major component prices to decline between now and the issuance of LNTP.").

[28] ETI Ex. 1 (Application) at 2; ETI Ex. 3A (Rainer Dir.) at 22; ETI Ex. 8 (Ruiz Dir.) at 5; ETI Ex. 5 (Kline Dir.) at 27.

[29] ETI Ex. 27 (Ruiz Reb.) at 3.

LNTP by July 15, 2022 (now passed).[30] At the time of the hearing, ETI's Board had approved up to $1.67 billion for the project.[31]

Included in those estimates are the hydrogen co-firing infrastructure costs, which have risen from $65 million upon filing the application[32] to about $91 million.[33]

Furthermore, Mr. Ruiz testified that he expects the cost of OCAPS to continue to rise even further before the issuance of a LNTP.[34] Mr. Viamontes testified that we are in "uncharted territory" in terms of possible cost escalations through the rest of 2022, due in part to the effects of inflation, the war in Ukraine, and supply chain issues.[35]

ETI's estimated cost to interconnect OCAPS at transmission voltage at the Sabine substation is $15.4 million.[36] Meanwhile, the expected cost of transmission interconnection upgrades associated with OCAPS has decreased from approximately $70 million to approximately $20 million.[37]

[30] Staff Ex. 21 at 3-4 (ETI response to Staff RFI No. 1-5, Addendum 1). ETI Ex. 8B (Ruiz Dir.) (First Periodic Report on Market Escalation, Feb. 2022); ETI Ex. 8C at 3 (Ruiz Dir.) (Third Periodic Report on Market, June 27, 2022); Tr. at 335-36 (Nguyen Cross).

[31] ETI Ex. 61 (ETI Board Minutes, Jun. 14, 2022).

[32] ETI Ex. 3A (Rainer Dir.) at 8; Staff Ex. 8 (ETI response to Staff RFI No. 1-7).

[33] Tr. at 201 (Ruiz Cross); TIEC Ex. 4 at 5 (ETI HSPM response to TIEC RFI 14-1, Addendum 1).

[34] Tr. at 205 (Ruiz Cross).

[35] Tr. at 18-19, 39 (Viamontes Cross).

[36] ETI Ex. 5 (Kline Dir.) at 24.

[37] Tr. at 314 (Kline Redir.).

In briefing and in testimony, ETI commits to update the parties regarding costs after the issuance of a PFD but before the Commission considers the case at a future open meeting. To do so, ETI will perform a true-up mechanism, which will allow ETI to lock-in certain prices under the EPC agreement.[38] Thus, according to ETI, the Commission and the parties will have the most up-to-date cost estimate for OCAPS prior to a final Commission decision.[39]

TIEC, OPUC, Sierra Club, and Staff express significant concerns with price escalations continuing to grow beyond the updated cost provided by ETI, which are discussed further below.

III. CERTIFICATE OF CONVENIENCE AND NECESSITY STANDARD

The Commission may grant or amend a CCN only upon finding that the certificate "is necessary for the service, accommodation, convenience, or safety of the public."[40] When making this determination, the Commission must consider:

(1) the adequacy of existing service;
(2) the need for additional service;
(3) the effect of granting the certificate on the recipient of the certificate and any electric utility serving the proximate area; and
(4) other factors, such as:

[38] ETI Ex. 8 (Ruiz Dir.) at 37-38.

[39] ETI Ex. 8 (Ruiz Dir.) at 37-38.

[40] PURA § 37.056(a); *see also id.* § 37.051(a) (underlying requirement that an electric utility obtain a CCN from the Commission to "directly or indirectly provide service to the public under a franchise or permit"); *id.* § 11.003(19) (In PURA, "'[s]ervice' has its broadest and most inclusive meaning . . . includ[ing] any act performed, anything supplied, and any facilities used or supplied by a public utility in the performance of the utility's duties under [PURA] to its patrons, employees, other public utilities, an electrical cooperative, and the public.").

(A) community values;

(B) recreational and park areas;

(C) historical and aesthetic values;

(D) environmental integrity;

(E) the probable improvement of service or lowering of cost to consumers in the area if the certificate is granted, including any potential economic or reliability benefits associated with dual fuel and fuel storage capabilities in areas outside the ERCOT power region; and

(F) to the extent applicable, the effect of granting the certificate on the ability of this state to meet the goal established by Section 39.904(a) of this title.[41]

These factors reflect potentially competing policies and interests whose relative weight will vary with the particular circumstances of each case.[42] Consequently, "[n]one of the statutory factors is intended to be absolute in the sense that any one shall prevail in all possible circumstances," but must instead be balanced to the end of furthering "the overall public interest."[43]

Additionally, PURA section 39.452(j) requires the Commission to ensure (1) the environmental integrity of the project, (2) the probable improvement of

[41] PURA § 37.056(c); *see also* 16 Tex. Admin. Code (TAC) § 25.101(b) ("[T]he commission may grant an application and issue a certificate only if it finds that the certificate is necessary for the service, accommodation, convenience, or safety of the public, and complies with the statutory requirements in [PURA] § 37.056.").

[42] *See Public Util. Comm'n of Tex. v. Texland Elec. Co.*, 701 S.W.2d 261, 266-67 (Tex. App.—Austin 1985, writ ref'd n.r.e.) ("To implement in particular circumstances such broadly stated legislative objectives and standards, the Commission must necessarily decide what they mean in those circumstances; and because some of them obviously compete *inter se*, the agency may in some cases be required to adjust or accommodate the competing policies and interests involved. For example, a 'need' for additional service implies a relative requirement, ranging from imperative need to one that is minimal; and, if a 'need' be sufficiently grave, it may have to prevail notwithstanding an adverse [e]ffect upon another interest, such as the environment," and *vice versa*).

[43] *Id.* at 267. *See also Hammack v. Pub. Util. Comm'n of Texas*, 131 S.W.3d 713, 723 (Tex. App.—Austin 2004, pet. denied).

service or lowering of cost to consumers in the area, and (3) that the generating facility satisfies the identified reliability needs of the utility.

After considering the listed factors, the Commission may grant the certificate as requested; grant the certificate for the construction of a portion of the requested facility or the partial exercise of the requested right or privilege; or refuse to grant the certificate.[44]

IV. ADEQUACY OF EXISTING SERVICE AND NEED FOR ADDITIONAL SERVICE (P.O. ISSUE NOS. 15-18)

A. Adequacy of Existing Service

No party disputes that ETI's existing service is adequate.

B. Need for additional Service

ETI asserts its need for additional capacity is based on the planned retirement of three aging generation plants while also meeting anticipated load growth in its service territory. TIEC, Sierra Club, and OPUC challenge both assertions.

[44] PURA § 37.056(b).

1. Deactivating Generation

By 2026, ETI plans to deactivate three aging generators at its Sabine Power Station, where ETI owns five gas-fired steam boiler units.[45] Below is a profile of the units planned for retirement.

	Planned Retirement Date	COD[46]	Age at Retirement	MW
Sabine 1	2023	1962	61	212
Sabine 3	2026	1966	60	418
Sabine 4	2026	1974	52	533

With these deactivations, ETI will lose a little over 1,000 MW of capacity.[47] Replacing this capacity is the primary driver for ETI's assertion concerning the need to ensure reliable service.[48] ETI will lose an additional 243.3 MW of capacity with the expiration of its Carville purchase power agreement (PPA) in 2022.[49]

ETI's evidence for deactivating Sabine 1 and 3 on their current deactivation dates, and the necessity of replacing their approximately 500 MW of capacity, is uncontested.[50] While Cities support the deactivation of Sabine 4, TIEC, Sierra Club, OPUC oppose it.

[45] ETI Ex. 4 (Weaver Dir.) at 14; TIEC Ex. 1 (Griffey Dir.) at 47.

[46] Commercial Operation Date.

[47] ETI Ex. 4 (Weaver Dir.) at 10-11, 20, Exhs. ABW-2 at Bates 37, ABW-5 at Bates 51, ABW-6 at 8 of 122.

[48] ETI Ex. 29 (Weaver Reb.) at 10.

[49] ETI Ex. 4A (Weaver Dir., Conf.) at 11, Table 3 (Bates 1).

[50] ETI Ex. 4 (Weaver Dir.), Exh. ABW-5 at 11-26 (Bates 53-68); Tr. at 474 (Griffey Cross).

a) Sabine 4

ETI witness Abigail Weaver, Director of Resource Planning and Market Operations, testified that ETI must make assumptions regarding the useful lives of its legacy fleet to properly plan for replacing aging units and enable an orderly, economic, and reliable transition to new resources.[51] In deciding whether to deactivate a generating plant, ETI, through its Enterprise Planning Group (EPG), assesses whether it is economic to sustain or extend the life of a unit.[52] In 2019, EPG conducted a portfolio analysis (2019 Portfolio Analysis) which evaluated operating Sabine 4 until 2034 and found that doing so poses substantial reliability and operational risks for customers and threatens ETI's ability to provide adequate service.[53]

b) Intervenor Positions

TIEC, Sierra Club, OPUC argue that Sabine 4 is too young to deactivate in 2026 and that its useful life should be extended as an alternative to building OCAPS notwithstanding the findings in the 2019 Portfolio Analysis.[54] These parties argue that there is no physical reason that Sabine 4 could not be operated for 60 years, assuming proper maintenance.[55] TIEC witness Charles Griffey testified that it is not uncommon for such plants to have a useful life of 60 years. Even ETI indicated in a prior CCN case that it "generally assumes a

[51] ETI Ex. 4 (Weaver Dir.) at 14.

[52] ETI Ex. 4 (Weaver Dir.) at 15-17, Exh. ABW-4.

[53] ETI Ex. 4 (Weaver Dir.) at 17-18; ETI Ex. 29 (Weaver Reb.) at 30-32.

[54] TIEC Ex. 1 (Griffey Dir.) at 14; OPUC Ex. 1 (Nalepa Dir.) at 12, 19-20.

[55] TIEC Ex. 1 (Griffey Dir.) at 47-48.

60-year operational life for solid fuel and steam generators unless evidence suggests a shorter or longer life assumption is appropriate."[56] Mr. Griffey and OPUC witness Karl Nalepa note that similar gas units at the same location, including Sabine 1 and 3, will be operated for 60 years or more,[57] and that Sabine 4's proposed service life is approximately 14% less than those plants.[58] OPUC argues that the service life of Sabine 4 is most appropriately assessed by comparing it to Sabine 1 and 3, rather than national averages, because those units will be retired with service lives of 60 years or more.[59]

Cities support deactivating Sabine 4, pointing to evidence that the Sabine 4 life extension is not a reasonable planning approach for customers.[60]

c) ETI's Position

ETI argues that extending the life of Sabine 4 is an irresponsible approach to resource planning, given its obligation to reliably serve its customers (current and future) and the considerable lead time it takes to procure new resources.[61]

ETI argues that extending the service life of Sabine 4 would be excessively risky to reliability. First, Ms. Weaver stated that the comparison to Sabine 1 and 3 is misplaced. She testified that the operational lives of these type of generators are

[56] Tr. at 705 (Weaver Cross); TIEC Ex. 52 at Bates 11 (D. 43958, Rebuttal Testimony of Stuart Barrett).

[57] TIEC Ex. 1 (Griffey Dir.) at 47; OPUC Ex. 1 (Nalepa Dir.) at 10.

[58] OPUC Ex. 1 (Nalepa Dir.) at 10.

[59] OPUC Reply Brief at 3-4.

[60] ETI Ex. 29 (Weaver Reb.) at 27-30.

[61] ETI Ex. 29 (Weaver Reb.) at 30, 39.

inversely proportional to their size.[62] Sabine 4 is larger and has been dispatched for more hours and at higher capacity factors than Sabine 1 and 3.[63] Ms. Weaver further testified that no natural gas-only steam boiler generators of Sabine 4's size have operated 60 years or more and doing so would be unprecedented.[64] The vast majority of gas-fired steam boiler generators operate less than 60 years, the average retirement age is 52.6 years, and the average deactivation age for steam generators over 500 MW, such as Sabine 4, is 39.4 years.[65] Accordingly, she stated there is no example to show that extending Sabine 4's service life to 60 is not very risky to reliability.[66]

Ms. Weaver further testified that Sabine 4 is already experiencing significant age-related issues that have increased its forced outage rate and degradation to its max capacity.[67] These issues include gas supply valve wear, water pump replacement and failures, stop-valve replacement, hot spots on the boiler, frequent tube leaks in multiple key components, and air duct failures.[68] A recent forced outage caused by a reheater tube failure that began in February took several months to resolve.[69] During the first six months of 2022, Sabine 4 was only available for approximately 30 days.[70] Over the past five years, Sabine 4's outage rate has

[62] ETI Ex. 29 (Weaver Reb.) at 28.

[63] ETI Ex. 29 (Weaver Reb.) at 28.

[64] ETI Ex. 29 (Weaver Reb.) at 31.

[65] ETI Ex. 29 (Weaver Reb.) at 31, Fig. 2.

[66] Tr. at 697-98 (Weaver Cross).

[67] ETI Ex. 29 (Weaver Reb.) at 33-35, Figs. 3-5.

[68] ETI Ex. 29 (Weaver Reb.) at 33-35, Figs. 3-5.

[69] ETI Ex. 29 (Weaver Reb.) at 35-36, Figs. 6-7.

[70] Tr. at 716 (Weaver Redir.).

increased 50% as compared to the previous five-year period.[71] Sabine 4's unforced capacity used by Midcontinent Independent System Operator (MISO) to determine capacity credit has recently decreased, and its Generator Verification Test Capacity has degraded approximately 30 MW over the past five years.

Moreover, according to Ms. Weaver, from a reliability standpoint and Loss of Load Expectation, extending Sabine 4 ranked worse than other options considered given its higher expected Equivalent Forced Outage Rate Demand (EFORd) and greater risk of investing in, maintaining, and operating as the chances of serious failures increase.[72]

Additionally, Ms. Weaver testified that sustainability investments to extend the life of Sabine 4 are not certain to improve the forced outage rate and capacity.[73] Conditions that can only be discovered by disassembling the unit could lead to unit failure from which the unit could not return to service.[74] This occurred with an ETI affiliate's unit (scheduled for near-term deactivation), wherein previously unknown damage revealed during a forced outage prevented it from operating to its planned deactivation date.[75] For that unit, incremental sustainability investments would have been futile and imprudent, as they would not have extended its service life.[76] Sabine 4's outage rate has been higher than other ETI

[71] ETI Ex. 29 (Weaver Reb.) at 32.

[72] ETI Ex. 29 (Weaver Reb.) at 18.

[73] ETI Ex. 29 (Weaver Reb.) at 29.

[74] ETI Ex. 29 (Weaver Reb.) at 32.

[75] ETI Ex. 29 (Weaver Reb.) at 32.

[76] ETI Ex. 29 (Weaver Reb.) at 32.

gas steam units in the years preceding their deactivation, and these type of units commonly experience dramatically increasing outage rates as they enter their final years of operation.[77] Based on historical experience involving other Entergy Operating Company's resources, the changes in unit operations based on market conditions, and a shift in unit wear drivers, ETI expects frequent forced outages for known and unknown causes to continue at Sabine 4.[78] Waiting until Sabine 4 suffers a catastrophic failure from which it cannot return to service, Ms. Weaver testified, creates significant reliability risks for ETI customers.[79]

Another concern, Ms. Weaver testified that Sabine 4 relies on steam, which is currently provided by Sabine 3 and 5.[80] With Sabine 3's retirement in 2026, Sabine 5 will be the sole source of steam for Sabine 4. If Sabine 5 were to experience an outage, planned or forced, Sabine 4 could not start without investing in an auxiliary boiler.[81] In 2020 and 2021, MISO committed at least one of Sabine 1, Sabine 3, or Sabine 4 for 83% of the time for addressing voltage and local reliability (VLR) issues, with Sabine 4 being committed for an average of 54% of that time.[82] The inability to start Sabine 4 without a steam source could cause operational and reliability issues if MISO calls on Sabine 4 as a VLR must-run unit to maintain system reliability, or if ETI needs to designate Sabine 4 as a must-run unit, and

[77] ETI Ex. 29 (Weaver Reb.) at 29-30; ETI Ex. 29A (Weaver Reb., Conf.) at 29-30.

[78] ETI Ex. 29 (Weaver Reb.) at 36.

[79] ETI Ex. 29 (Weaver Reb.) at 3-4.

[80] ETI Ex. 29 (Weaver Reb.) at 37.

[81] ETI Ex. 29 (Weaver Reb.) at 37-38.

[82] ETI Ex. 26 (Owens Reb.) at 12-13, Fig. 1.

Sabine 4 is not already online.[83]

Finally, Ms. Weaver testified regarding environmental compliance concerns. Sabine 4 has been derated or taken offline several times to comply with nitrogen oxide (NOx) emission limitations.[84] A proposed rule by the United States Environmental Protection Agency (EPA) relating to NOx emissions would require ETI to spend approximately $60 million to install Selective Catalytic Reduction controls by 2026 to continue operations, which is incremental to the estimated capital upgrades modeled in ETI's 2019 Portfolio Analysis (see PFD Section VI.A.5 below).[85]

d) Responses

TIEC and Sierra Club respond that Ms. Weaver overstates the unprecedented nature of extending the service life of Sabine 4 to 60 years. They note that extending its life is only unprecedented because no natural gas-only steam boiler generators of Sabine 4's size were placed into service more than 60 years ago, given that the oldest natural such generator is only 57 years old.[86] Sierra Club argues that even accepting a 57-year maximum life, Sabine 4 could operate through 2031. TIEC further notes that ETI made its decision to retire Sabine 4 in 2026, contingent on OCAPS being constructed.[87]

[83] ETI Ex. 29 (Weaver Reb.) at 37-38.

[84] ETI Ex. 29 (Weaver Reb.) at 38.

[85] ETI Ex. 29 (Weaver Reb.) at 38.

[86] Tr. at 696, 706 (Weaver Cross); TIEC Ex. 64 (HSPM).

[87] ETI Ex. 4 (Weaver Dir.), Exh. ABW-5 at 8-9, 28 (Bates 50-51, 70 of 260) (requesting to deactivate Sabine 4 "in 2026, or at the time OCAPS reaches Commercial Operations").

TIEC points to evidence demonstrating that there are numerous plants of this type that are (i) still in operation, (ii) approaching 60 years of service, and (iii) not scheduled for retirement at this time.[88] TIEC points to other similar plants with planned retirement dates of 60 years or more.[89] Additionally, TIEC places great significance on ETI having considered operating Sabine 4 until 2034 in its 2019 Portfolio Analysis. TIEC argues that because ETI admits that all five portfolios were reasonable alternatives and would meet the Loss-of-Load standard in the WOTAB region for measuring reliability, ETI must have considered operating Sabine 4 for 60 years as a viable option.[90]

TIEC further argues that Sabine 4's dependence on steam can be remedied with a boiler, and that ETI has not claimed this solution would be prohibitively expensive.[91]

Without disputing that the maintenance issues Sabine 4 is experiencing are a sound basis for its retirement, Sierra Club argues that nothing requires it to be retired in just four years; instead, the "retirement date should be flexible enough within a reasonable range of near-term years to allow adjustment to enable procurement of the lowest-cost portfolio of replacement resources."[92] Sierra Club also argues that ETI failed to reasonably or realistically quantify the costs associated

[88] TIEC Ex. 64 (HSPM).

[89] TIEC Reply Brief at 15.

[90] ETI Ex. 4 (Weaver Dir.), Exh. ABW-6 at Bates 115 of 260.

[91] TIEC Reply Brief at 17.

[92] Sierra Club Initial Brief at 9.

with continuing to operate Sabine 4.

Sierra Club further disputes ETI's stated environmental compliance risks of continuing to operate Sabine 4 beyond 2026. Sierra Club notes that the NOx rule has not yet been adopted by the EPA and could subject to protracted legal challenges, as have other such EPA rules, and $60 million could be avoided by the rule's proposed alternative of purchasing emission credits.[93]

e) Analysis

The ALJs find the overwhelming evidence shows that Sabine 4 should be deactivated as soon as a replacement can be found. Whether Sabine 4 is deactivated in 2026, or somewhat sooner or later, the evidence nevertheless supports not waiting until catastrophic failure to find a replacement.

Sabine 4 is a roughly 500 MW unit that ETI and MISO have historically relied upon to support regional reliability, and it is currently experiencing significant age-related maintenance issues that make its reliability a present uncertainty. It has an increasing forced outage rate—available only 30 days in the first half of 2022. Additionally, it has been derated or taken offline to comply with NOx emission limitations. ETI diligently considered extending its life and found that extension would pose reliability risks without any commensurate economic benefit. Specifically, ETI analyzed operating Sabine 4 to 2034, longer than any supercritical unit of its size, and the analysis showed that it would have greater total

[93] Tr. at 682 (Weaver Cross); *see also* 87 Fed. Reg. at 20036-01 ("The Agency proposes establishing nitrogen oxides emissions budgets requiring fossil fuel-fired power plants in 25 states to participate in an allowance-based ozone season trading program.").

supply costs across a wide range of future scenarios and provide considerably less energy coverage than OCAPS.[94] Assessing the extension of Sabine 4's life does not concede that doing so is the best viable option, only that it was evaluated.[95]

In light of this evidence, intervenors' arguments that Sabine 4 could be pushed to operate up to and past 60 years are not persuasive. The Company should not be required to engage in heroic efforts to test whether Sabine 4 will be the first of its kind to live to 60 years. The average life of generation units of similar size and type is 39 years.[96] The dearth of Sabine 4-type units operating for 60 years does not negate its unprecedented nature; and it does not follow that simply waiting will result in any new information regarding its longevity. The ALJs find that Sabine 4 should be retired as planned, thereby creating a need for replacing its generation capacity.

2. Load Growth

Although plant retirements is the primary driver of the need for OCAPS, Ms. Weaver testified that ETI needs "additional long-term generating capacity to meet its customers' future resource needs, and to satisfy adequacy requirements."[97] Those resource needs include projected load growth of approximately 1,000 MWs by 2026 and 1.4 gigawatts (GW) by 2031, when accounting for a reserve margin.[98] ETI's coincident peak load is projected to grow

[94] ETI Ex. 4 (Weaver Dir.) at 20-22, Exh. ABW-6 at 19 (Bates 22-24, 109); ETI Ex. 29 (Weaver Reb.) at 21.

[95] ETI Ex. 4A (Weaver Dir., Conf.), Exh. ABW-5 (Bates 3).

[96] ETI Ex. 29 (Weaver Reb.) at 31; Tr. at 716 (Weaver Redir.).

[97] ETI Ex. 29 (Weaver Reb.) at 10; ETI Ex. 4 (Weaver Dir.) at 9, Exh. ABW-5 at Bates 77.

[98] ETI Ex. 4 (Weaver Dir.) at 11-12.

10.3% (or 348 MW) by 2026 and 13.3% (or 448 MW) by 2031.[99] Energy needs are also expected to increase: ETI is projected to be short 9.2 terawatt-hours (or 40% of customer energy needs) in 2026.[100] According to Ms. Weaver, this results in an incremental need for a significant amount of economic, reliable, and sustainable long-term capacity over the planning horizon.[101]

ETI witness William John, senior finance manager, discussed how ETI's load forecast is developed, which includes statistical modeling, out-of-model adjustments, and estimates for specific large industrial customers.[102] ETI witness Ryan Magee, industrial accounts manager, explained that the sales forecast for large industrial customers is developed through discussions between customers (or potential customers), which is then fed into ETI's Economic Development Pipeline tracker and continuously updated with the latest information to gauge when and if projects will materialize.[103] At the time the application was filed, the Economic Development Pipeline consisted of 15 active industrial projects with in-service dates through 2025, with a total potential load of 1,172 MW. Only 556 MW of these active projects were included in ETI's 2021 business plan (BP21) forecast for 2026 going forward.[104] Mr. Magee testified that there are good indications that additional industrial loads could materialize during that forecast period, including

[99] ETI Ex. 1 (Application) at 2; ETI Ex. 4 (Weaver Dir.) at 11.

[100] ETI Ex. 4 (Weaver Dir.) at 12.

[101] ETI Ex. 4 (Weaver Dir.) at 11, Exh. ABW-3 (Capacity Position Analysis) (Bates 13, 39).

[102] ETI Ex. 15 (John Supp. Dir.) at 3.

[103] ETI Ex. 6 (Magee Dir.) at 2-6.

[104] ETI Ex. 6 (Magee Dir.) at 9, Exh. RM-1 (HSPM).

some of the on-hold projects that ETI is negotiating.[105] For example, an additional 1,195 MW of industrial projects that were on-hold are expected to return to active status and ultimately materialize.[106] One on-hold industrial project has returned to active status and is on track to be completed in 2024.[107] Mr. John testified that, based on the forecast's conservatism, there is a high probability that all of the industrial load included in BP21, if not more, will ultimately be completed.[108]

TIEC, Sierra Club, and OPUC challenge ETI's load forecast. TIEC and Sierra Club argue that ETI's load forecasting overestimates load growth.[109] These arguments focus on shortcomings in ETI's previous load forecasts, resources in ETI's 2022 business plan (BP22), and its reserve margin. Sierra Club further argues that the load projections fail to sufficiently account for expanding interruptible and energy conservation programs. OPUC does not challenge ETI's load forecast but argues that its need could be delayed principally by extending the life of Sabine 4.

Cities support ETI's load forecast, noting that ETI has been short on capacity for several years and has had to purchase between 74 MW to 787 MW of capacity every year between 2015 and 2021 in the MISO Planning Resource Auction (PRA).[110] This, Cities argue, shows that ETI tends to under-estimate load and

[105] ETI Ex. 6 (Magee Dir.) at 9.

[106] ETI Ex. 6 (Magee Dir.) at 8.

[107] ETI Ex. 24 (Magee Reb.) at 2-3.

[108] ETI Ex. 15 (John Supp. Dir.) at 6-7.

[109] Sierra Club Ex. 1 (Glick Dir.) at 4, 9-13; TIEC Ex. 1 (Griffey Dir.) at 50-51.

[110] TIEC Ex. 15 (ETI response to TIEC RFI No. 12-7).

capacity needs.

a) Historical Accuracy

TIEC and Sierra Club argue that ETI's load forecast is not reliable because ETI's load forecasts have historically overstated growth. TIEC references testimony from 2015 in which an ETI witness projected loads would grow by 700 MW by 2023,[111] which has since proven to be too high by over 500 MW.[112] TIEC notes that on a MISO coincident peak basis, ETI's loads actually shrank by approximately 30 MW from 2015 to 2020, and are projected to grow by less than 80 MW from 2015 to 2023.[113] Sierra Club argues that ETI's projected growth over the next five years (around 2% per year for a total of 10.3%) is double the growth over the previous five years (2016-2020), when ETI's peak load grew by only 4.6%, or 1.1% per year.[114]

ETI responds that its current load projections are more accurate than in 2015, arguing that those projections were driven primarily by household income and an internal multiplier effect based on expected new industrial projects.[115] Today, ETI uses the Itron suite of software and a broader set of economic data inputs, which is benchmarked for accuracy, and has tended to understate forecasted load, not overstate it.[116]

[111] TIEC Ex. 52 at 7 (Docket No. 43958, Rebuttal Testimony of Stuart Barrett); Tr. at 457-64 (John Cross).

[112] ETI Ex. 20 (John Reb.), Exh. WCJ-SD-2 (Bates 15 of 17); Tr. at 464-65 (John Recross).

[113] ETI Ex. 15 (John Supp. Dir.), Exh. WCJ-SD-2 (Bates 17 of 17).

[114] Sierra Club Ex. 1 (Glick Dir.) at 9.

[115] TIEC Ex. 52 at 7-8 (Docket No. 43958, Rebuttal Testimony of Stuart Barrett).

[116] ETI Ex. 15 (John Supp. Dir.) at 4, 6, 11; ETI Ex. 20 (John Reb.) at 5-7; Tr. at 462 (John Redir.).

ETI further presented evidence that before the COVID-19 pandemic, all of the industrial projects that were included in ETI's load forecast were completed.[117] ETI argues that load growth in the industrial sector and the accuracy of ETI-forecasted industrial projects in 2017 to 2019 is more representative of its expected industrial load growth moving forward.[118]

ETI further notes that from 2013 to 2021, its retail peak load increased 345 MW, or 10%, reflecting significant load growth over the last eight years.[119] ETI argues that Sierra Club's figures are misleading because it relies on a narrow set of annual data.[120] When looking at a broader data set, Mr. John showed ETI's load has grown at a level comparable to the BP21 forecast.[121]

Ms. Weaver testified that ETI has already executed an electric service agreement with a new industrial customer for 270 MW (almost half of the 556 industrial MWs included in ETI's load forecast).[122] Mr. Magee testified that its industrial load forecasting is conservative, including less than half of the projects in its pipeline and that probability weights the subset of projects that are included.[123] Mr. Griffey acknowledged that Houston Lighting and Power's load forecasting team, which he supervised, assigned probabilities to potential new industrial

[117] ETI Ex. 24 (Magee Reb.) at 3, Exh. RM-R-1 (Bates 5, 11).

[118] ETI Ex. 24 (Magee Reb.) at 2-3.

[119] ETI Ex. 20 (John Reb.) at 2.

[120] ETI Ex. 20 (John Reb.) at 2, Exh. WCJ-R-2 (Bates 4, 15).

[121] ETI Ex. 20 (John Reb.) at 2, Exh. WCJ-R-2 (Bates 4, 15).

[122] ETI Ex. 29 (Weaver Reb.) at 9; ETI Ex. 24 (Magee Reb.) at 2.

[123] ETI Ex. 24 (Magee Reb.) at 2-3.

projects, just as ETI does.[124] Moreover, Mr. Griffey agreed that the data points ETI takes into account to assign probabilities to new projects are reasonable.[125]

ETI further argues that any reasonably expected variability in its load forecast will not cause it to be substantially long (i.e., have surplus) on capacity or energy for an extended period of time; the forecast would have to decrease by approximately 200 MW to result in a long position for more than five years even at the lower bound of capacity need, and by over 500 MW at the upper bound.[126]

b) Low-Growth Assumptions

Sierra Club asserts that ETI failed to evaluate any reference scenarios or sensitivities with lower load growth assumptions,[127] and therefore provided no data on the impact of projected market prices and projected revenue of building the plant and ultimately not needing as much energy or capacity as projected to serve internal load.[128]

ETI responds that it did evaluate reference scenarios and sensitivities with a lower load growth assumption. The 2019 Portfolio Analysis included three load forecasts for low, reference, and high demand.[129] The low demand case assumed a declining customer count for the residential and commercial sectors as well as

[124] ETI Ex. 6 (Magee Dir.) at 7; Tr. at 499-01 (Griffey Cross).

[125] Tr. at 501-502 (Griffey Cross).

[126] ETI Ex. 29 (Weaver Reb.) at 10.

[127] Sierra Club Ex. 1 (Glick Dir.) at 13.

[128] Sierra Club Ex. 1 (Glick Dir.) at 13.

[129] ETI Ex. 4A (Weaver Dir., Conf.), Exh. ABW-6 at 96 (Bates 145).

declining usage per customer in those same sectors due to increases in energy efficiency and new technologies.[130] ETI compared all the portfolios using that low demand case.[131]

c) Interruptible Load and Energy Efficiency

Sierra Club argues that ETI could meet its capacity needs by expanding its interruptible load or energy efficiency.[132] Sierra Club witness Devi Glick testified that ETI has historically underinvested in energy efficiency relative to other investor owned utilities, and increasing the MWs of capacity included in its interruptible load program would provide a significant portion of ETI's stated capacity need for this decade.[133] On cross examination, however, Ms. Glick proved unfamiliar with the Commission's energy efficiency rules and whether they permitted her recommendation to expand energy efficiency programs, as well as with ETI's performance awards for exceeding its expected energy efficiency targets.[134]

ETI responds that expanding interruptible load and energy efficiency to reduce its projected capacity need is impractical. ETI's peak load in 2020 and 2021 was approximately 3.7 GW,[135] and ETI needs to replace approximately 1.1 GW of

[130] ETI Ex. 4A (Weaver Dir., Conf.), Exh. ABW-6 at 96 (Bates 145).

[131] ETI Ex. 4A (Weaver Dir., Conf.), Exh. ABW-6 at 67 (Bates 116).

[132] Sierra Club Initial Brief at 12-13.

[133] Sierra Club Ex. 1 (Glick Dir.) at 15.

[134] Tr. at 548-49, 554, 556 (Glick Cross); Docket No. 52067, Final Order (Dec. 16, 2021) at 17 (Ordering Paragraph [OP] No. 2(d) (awarding performance bonus)).

[135] ETI Ex. 20 (John Reb.) at 6.

capacity associated with the Sabine Units.[136] Thus, ETI would need to expand its interruptible service to over 30% of its peak load to obtain an equivalent amount of replacement capacity, which is three times the MISO average cited by Sierra Club.[137]

ETI further argues that comparing its energy efficiency performance to national averages is misleading because ETI's sales mix includes a much larger percentage of industrial consumption than other utilities, and that most energy efficiency programs are not aimed at industrial customers.[138] Mr. John noted that ETI's load forecast takes into account the cumulative effects of ETI's energy efficiency programs as well as organic energy efficiency that occurs naturally through technological improvements.[139]

ETI argues that there is no reasonable basis to conclude that ETI should be implementing energy efficiency measures at a different pace or on a different scale given its energy efficiency achievements and rewards.[140] Moreover, ETI argues the acceleration of such measures would not materially affect its capacity need.[141]

d) Planned Resource Additions

TIEC, OPUC, and Sierra Club argue that ETI's projected capacity need

136 ETI Ex. 4 (Weaver Dir.) at 4, 9-11.

137 Sierra Club Initial Brief at 13.

138 ETI Ex. 20 (John Reb.) at 7-8.

139 ETI Ex. 20 (John Reb.) at 8-9.

140 Docket No. 52067, Order at 17 (OP No. 2) (Oct. 16, 2021).; Docket No. 50803, Order at 16 (OP No. 2(d)) (Oct. 16, 2020).

141 Tr. at 771 (John Redir.).

fails to account for other planned resources.[142] ETI's BP22 included new solar additions between 2025 and 2029, which they argue, diminish or obviate the need for new capacity.[143]

ETI responds that the incremental solar generation included in the BP22 Supply Plan is needed in addition to, not in lieu of, OCAPS.[144] Moreover, ETI argues that all of the incremental solar MW are placeholders—not actual identified or certified resources—and that there is no certainty that the full 1,000 MW will be procured within the timeframe contemplated by the supply plan.[145] Ms. Weaver testified that even if the solar additions planned for 2025 come to fruition, ETI would still be short 986 MW in 2026 without OCAPS, and with OCAPS, ETI would only be long approximately 140 MW in 2026, and then short again in 2028.[146] Ms. Weaver further testified that the additional solar capacity is, in part, enabled by OCAPS coming online in 2026 to replace dispatchable legacy generation at the Sabine Power Station.[147]

ETI further contends the incremental solar resources are not a suitable alternative to OCAPS in terms of capacity, energy, and operating characteristics.[148] The incremental planned solar was added to address the capacity and energy needs

[142] OPUC Ex. 1 (Nalepa Dir.) at 19–20.

[143] Sierra Club Ex. 1 (Glick Dir.) at 21-22; TIEC Ex. 1 (Griffey Dir.) at 46-47; *see* OPUC Ex. 15 (HSPM), (ETI response to TIEC RFI No. 11-2, Att. P); TIEC Ex. 1A (Griffey Dir., Conf.) at 9, 45-47.

[144] ETI Ex. 29 (Weaver Reb.) at 23, 40.

[145] ETI Ex. 29 (Weaver Reb.) at 22-23; Tr. at 403-04 (Nguyen Cross, Conf.), 416-17 (Nguyen Redir.).

[146] ETI Ex. 29 (Weaver Reb.) at 23 (Bates 25); ETI Ex. 29A (Weaver Reb., Conf.), Exh. ABW-R-2.

[147] ETI Ex. 29 (Weaver Reb.) at 23.

[148] ETI Ex. 29 (Weaver Reb.) at 41-44.

of large industrial customers who seek sustainable resources, but OCAPS is the foundational unit to provide long-term, reliable, dispatchable power to both meet customer demand and facilitate the addition of renewable resources to meet needs above what OCAPS can provide.[149]

Finally, ETI notes that the BP22 Supply Plan includes the assumptions regarding coal deactivations and an updated load forecast, which TIEC and Sierra Club overlook.[150] The earlier deactivation of coal units increases ETI's need for dispatchable capacity in 2026.[151]

e) Surplus Capacity

Mr. Griffey testified that there is capacity surplus in MISO South that could be transmitted to ETI to supply all or part of its 2026 needs.[152] ETI witness Nicholas Owens, outside consultant on generation planning and operations, testified that this surplus is not a reliable source of capacity and explained that the surplus will shrink if resource additions do not offset load growth and retirements.[153] He testified that in delivery year 2021/2022, the surplus was approximately 10%, which is expected to drop by 5% for delivery year 2022/2023.[154] The remaining 5% surplus is not large and could quickly disappear.[155] Therefore,

[149] ETI Ex. 29 (Weaver Reb.) at 40-41.

[150] ETI Ex. 29 (Weaver Reb.) at 41-44.

[151] ETI Ex. 29 (Weaver Reb.) at 22.

[152] TIEC Ex. 1 (Griffey Dir.) at 34-35, Fig. 8.

[153] ETI Ex. 26 (Owens Reb.) at 8.

[154] ETI Ex. 26 (Owens Reb.) at 7-8.

[155] ETI Ex. 26 (Owens Reb.) at 8.

the current surplus does not guarantee there will be a surplus in the future.[156]

f) Reserve Margin

ETI's load growth projections include a long-term reserve margin of 12.69%,[157] whereas MISO's short-term reserve margin is 8.7% to 9.4%.[158] TIEC and Sierra Club argue that ETI's reserve margin is unreasonably high, exceeding MISO's reserve margin calculation by over 100 MW in 2026.[159]

Mr. Owens explained that both MISO's and ETI's planning reserve margins are estimates of the amount of capacity, above the forecast of coincident peak load, that would be necessary to ensure that firm load would be curtailed only once every 10 years (the 1-in-10 standard).[160] MISO calculates its reserve margin for the upcoming year, while ETI calculates its reserve margin for a four-year period, representing the approximate amount of time necessary to deploy an incremental resource.[161] Because ETI is forecasting further out in time, there is more uncertainty associated with the weather-normalized load forecast, which causes ETI's longer-term view to yield a higher value than MISO's one-year view.[162] However, both views use the same approach to determine the weather-normalized forecast uncertainty, which is based on national gross domestic product (GDP) and

[156] ETI Ex. 26 (Owens Reb.) at 7.

[157] ETI Ex. 12 (Owens Dir.) at 5-21.

[158] ETI Ex. 26 (Owens Reb.) at 29.

[159] TIEC Ex. 1 (Griffey Dir.) at 48-50; Tr. at 98 (Weaver Cross).

[160] ETI Ex. 12 (Owens Dir.) at 21; ETI Ex. 26 (Owens Reb.) at 25.

[161] ETI Ex. 12 (Owens Dir.) at 21-23; ETI Ex. 26 (Owens Reb.) at 25-27.

[162] ETI Ex. 12 (Owens Dir.) at 22; ETI Ex. 26 (Owens Reb.) at 26.

its correlation to electricity demand.[163]

TIEC argues that ETI's reserve margin is improperly tied to GDP.[164] This is based on Mr. Griffey's testimony that GDP and electric consumption have become uncoupled over the last 15 years, which he based on the correlation between electric sales and GDP between 2001-2019.[165] According to Mr. Griffey, ETI should base its reserve margin on the uncertainty in its own forecast.[166]

Mr. Owens explained that he replicated MISO's analysis, which began in 1992 and shows a strong correlation between GDP and electricity consumption.[167] ETI argues that going short for a year or two instead of planning for sufficient lead time to deploy an incremental resource would expose ETI customers to multi-year periods of unreasonably high risk related to regional or zonal capacity shortages and the resulting risk of load shed, reduced reliability, and extremely high prices. Avoiding these risks and complying with MISO's resource adequacy construct requires ETI to plan to hold sufficient reserves far enough in advance to allow for deployment of a new resource, which requires a four-year period.[168]

3. Analysis

The ALJs find that ETI has demonstrated sufficient load growth to justify

[163] ETI Ex. 26 (Owens Reb.) at 27.

[164] TIEC Reply Brief at 8-10.

[165] TIEC Ex. 1 (Griffey Dir.) at 49-50, Fig. 12.

[166] TIEC Ex. 1 (Griffey Dir.) at 49.

[167] ETI Ex. 26 (Owens Reb.) at 27, 31, Fig. 3; Tr. at 536-37 (Owns Cross).

[168] ETI Ex. 26 (Owens Reb.) at 26-27; ETI Ex. 12 (Owens Dir.) at 22-23.

the incremental 132 MW by which OCAPS would exceed the capacity lost with the retirement of the Sabine units. The nominal 1,215 MW of OCAPS capacity[169] would replace 1,083 MW of installed capacity at Sabine.[170] This 132 MW difference has already been eclipsed by the 270 MW industrial contract executed since the case has been pending[171] and the 243 MW Carville PPA expiration in 2022.[172] The planned coal deactivations contemplated in ETI's BP22 further increase ETI's need for dispatchable capacity in 2026. Thus, ETI has justified the 132 MW exceedance without regard to the accuracy of its forecasting or reserve margin.

However, the evidence shows that ETI's load forecast likely is understated, notwithstanding its 2015 forecasts. Although ETI has supplemented between 74 MW to 787 MW of its capacity needs between 2015 and 2021 with PRA purchases,[173] that tends to support its need for short- and long-term capacity, and does not show that practice is a reliable long-term plan.

Moreover, the evidence shows that ETI's recent load forecasts are reliable. Before the pandemic, all of the industrial projects included in ETI's load forecast were completed.[174] ETI's BP21 load growth assumptions are conservative, including only 556 MW of total potential load of the 1,172 MW industrial load in its

[169] ETI Ex. 8 (Ruiz Dir.) at 4.

[170] ETI Ex. 4 (Weaver Dir.) at 11.

[171] ETI Ex. 29 (Weaver Reb.) at 11.

[172] ETI Ex. 4A (Weaver Dir., Conf.), Table 3, 11 (Bates 1).

[173] TIEC Ex. 15 (ETI response to TIEC RFI No. 12-7).

[174] ETI Ex. 24 (Magee Reb.) at 3, Exh. RM-R-1 (Bates 5, 11).

Economic Development Pipeline with in-service dates through 2025, which does not account for the 1,195 MW of industrial projects that are on hold and may become active, or the additional industrial loads that could materialize during that forecast period. The ALJs therefore find that there is a high probability that a majority, if not all, of the industrial load included in BP21 will ultimately be completed.[175]

Additionally, the evidence shows that the resource additions in ETI's BP22 Supply Plan are needed in addition to the 1,215 MW of capacity OCAPS would provide, and at any rate are not firm resources. It would be a cruel irony if ghosts of future resources could haunt current applications. Using such planned resources offensively to frustrate implementing fully developed resources necessary to address a certain need would effectively punish the applicant for prudent planning. Regardless, the evidence shows that the solar additions would not meet ETI's capacity need and are not a suitable alternative to OCAPS in terms of capacity, energy, and operating characteristics.[176]

Finally, the ALJs find ETI's reserve margin reasonable. ETI's four-year planning horizon reasonably accounts for accounts for long-term uncertainty by accounting for the approximate time to bring a new resource to operation.

Given the ALJs' findings regarding the retirement of Sabine 4 and ETI's projected load growth, the ALJs conclude that ETI has demonstrated a clear and

[175] ETI Ex. 15 (John Supp. Dir.) at 6-7.

[176] ETI Ex. 29 (Weaver Reb.) at 41-44.

pressing need for additional service.

V. EFFECT OF GRANTING THE CCN ON ETI AND OTHER ELECTRIC UTILITIES (P.O. ISSUE NO. 21)

The effect of granting the CCN on ETI and other electric utilities must be viewed in the context that ETI is a part of MISO, and is largely uncontested.

A. OCAPS Effect on Energy Prices

ETI explains that MISO operates organized markets (Day-Ahead and Real-Time) for energy. Generation owners offer to sell energy into the markets, generally at their variable cost. Load-serving entities (LSE) also bid into those markets the amount of energy they expect to purchase from the markets to serve their respective loads. MISO matches loads to energy sources and selects the lowest-cost sources to generate sufficient energy to serve the expected load, subject to security constraints that affect reliability of the grid. Generators then dispatch or operate as instructed by MISO and generate energy that is delivered to the loads via the transmission and distribution systems.

OCAPS is expected to lower locational marginal prices (LMPs)—the cost of energy in the MISO markets. As the newest generation of CCCT technology, OCAPS will operate at a lower heat rate and lower variable cost because it will use less fuel to generate an equivalent amount of energy produced by less efficient generation. As such, OCAPS is expected to be committed and dispatched at a high rate to produce energy to displace energy currently being supplied by less efficient generation, thereby reducing LMPs.[177] ETI witness Phong Nguyen testified that output from ETI's production cost modeling in the Economic Evaluation (see PFD Section IX.B) shows that OCAPS will cause LMPs to be reduced over the life of the unit.[178] Thus, utilities operating in MISO South, including ETEC, can expect to enjoy the benefit of these lower LMPs. The ability of OCAPS to lower energy costs in MISO South can also be expected to make lower cost energy available for transfer to MISO North.[179]

At the same time ETI sells its generation into the MISO markets, it also purchases from the MISO markets all the energy needed to serve its customers. ETI is charged the LMP for that energy and that cost is passed through to customers as an eligible fuel expense. ETI argues that because OCAPS will generate energy at a lower cost than less efficient units but will be paid the LMP for that energy set by the highest cost unit, OCAPS will earn net margins. These net margins are then credited to eligible fuel expenses, offsetting the cost ETI pays for energy purchased from MISO. ETI predicts that these eligible fuel cost savings will range from \$108.6 million to \$204.7 million in the first year of operation.[180] These savings were further projected to offset (or break even on) the total cost of the unit in an eight- to ten-year timeframe.[181]

No party challenges that lower cost energy generated by OCAPS can be

[177] ETI Ex. 25 (Nguyen Reb.) at 41-43.

[178] ETI Ex. 16A (Nguyen Supp. Dir., Conf.) at 2.

[179] ETI Ex. 16 (Nguyen Supp. Dir.) at 5; ETI Ex. 16A (Nguyen Supp. Dir., Conf.) at 6.

[180] ETI Ex. 7 (Nguyen Dir.) at 25; ETI Ex. 7A (Nguyen Dir., Conf.), Exhs. PDN-2 at 31, PDN-3.

[181] ETI Ex. 7 (Nguyen Dir.) at 25, n. 8.

expected to displace higher cost energy generated by less efficient resources and thus generate net margins to offset energy costs. TIEC argues, however, that the impact of OCAPS on LMPs and congestion costs are unrealistic because ETI calculated the dollar impact based on unrealistic assumptions (discussed below).[182]

B. OCAPS Effect on Congestion Charges

The marginal cost of congestion is a component of the LMP. The output from ETI's production cost modeling in its Economic Evaluation showed that the marginal cost of congestion will be reduced over the life of the unit (discussed below).[183] No party disputes that OCAPS is expected to reduce congestion costs.

C. OCAPS Effect on Reliability-Must-Run Designations

Mr. Nguyen explained that the reliability-must-run designation refers to MISO's instruction that a unit must run out of economic merit order to support the reliability of the transmission system. This is a security constraint in solving for unit commitment and dispatch, and it may result in VLR Uplift charges to compensate the designated generator for costs incurred to operate as instructed by MISO.[184]

Mr. Nguyen further explains that transmission security constraints were included as inputs in ETI's production cost modeling. With OCAPS included in the modeling, ETI contends, the transmission system usage threshold for trigging

[182] TIEC Reply Brief at 43.

[183] ETI Ex. 16 at 2-3 (Nguyen Supp. Dir.); ETI Ex. 16A (Nguyen Supp. Dir., Conf.) at 2.

[184] ETI Ex. 16 at 3-4 (Nguyen Supp. Dir.); ETI Ex. 16A (Nguyen Supp. Dir., Conf.) at 4.

potential VLR Uplift charges increased (or improved) by 1,200 MW. This result indicates that OCAPS would have the effect of reducing reliability-must-run designations.[185]

D. OCAPS Effect on Reserve Requirements

ETI argues that OCAPS is necessary to satisfy ETI's reserve requirements following the deactivation of the Sabine units, as discussed above (see PFD Section IV.B.2).

Based on the evidence and argument presented, the ALJs conclude that granting the CCN application will have a positive impact on the certificate holder and other utilities because it would reduce LMPs, congestion costs, and reliability-must-run designations and satisfy ETI's reserve requirements. TIEC's arguments regarding the Economic Evaluation are addressed below.

VI. ADDITIONAL FACTORS UNDER PURA § 37.056

Regarding the additional factors, ETI argues that there would be positive or minimal environmental impacts because OCAPS will be located at an existing generation site. Deborah Sexton is ETI's Environmental Services Manager and her testimony in that regard is uncontested.

A. Environmental Integrity (P.O. Issue Nos. 25, 26)

Ms. Saxton testified that that the co-location of OCAPS at ETI's Sabine

[185] ETI Ex. 16 at 3-4 (Nguyen Supp. Dir.); ETI Ex. 16A (Nguyen Supp. Dir., Conf.) at 4.

Power Station will avoid the environmental impact that would otherwise be incurred at a greenfield site and will result in only a minimal incremental effect on the environment.[186] The project will result in permanent impacts to approximately 26 acres of previously disturbed industrial land located adjacent to the Sabine Power Station for the construction of the new combustion turbines, heat recovery steam generators, the steam turbine generator, the evaporative cooling tower, and other associated new equipment.[187]

To assess the impact of OCAPS' construction on the environmental integrity of the surrounding area, ETI retained the services of a third-party consultant, Environmental Resources Management Southwest, Inc. (ERM), to develop an Environmental Assessment (EA).[188] As part of the EA development, ERM evaluated the potential for adverse impacts to identified natural resources and sensitive receptors in the area and recommended avoidance and mitigation measures ETI should employ for OCAPS.[189] ERM did not identify any significant issues associated with the construction or operation of OCAPS. The overall findings of the EA were that OCAPS' effects on environmental receptors would result in environmental consequences that would vary in the range of negligible to moderate prior to the implementation of mitigation measures and, with the implementation of mitigation measures, the consequences would be manageable and reasonable.[190] As such, ETI contends that there will be minimal adverse effects

[186] ETI Ex. 9 (Saxton Dir.) at 5.

[187] ETI Ex. 9 (Saxton Dir.) at 4.

[188] ETI Ex. 9 (Saxton Dir.), Exh. DS-1 (Bates 27-114).

[189] ETI Ex. 9 (Saxton Dir.) at 6.

[190] ETI Ex. 9 (Saxton Dir.) at 8.

due to the OCAPS-related transmission line modifications because they will be located within existing rights-of-way or previously disturbed areas.[191]

Staff notes that there will be some clearing of vegetation necessary for the project construction but otherwise no major impacts since the area is already used for industrial purposes.[192] Staff also states that aesthetics would be minimally impacted for this reason.

1. Climate and Air Quality

Though there will be short- and long-term effects on air quality resulting from the construction of OCAPS, Ms. Saxton testified that ETI will use best management practices and Best Available Control Technology to reduce emissions (including the use of combustion turbines with dry low-NOx burners, oxidation catalysts, selective catalytic reduction, and low sulfur fuel), and non-contact cooling towers with drift eliminators to address any long-term impacts to air quality.[193] Ms. Saxton stated that stack design and location will also reduce air quality impacts and that the OCAPS air emissions were modeled using EPA- and Texas Commission on Environmental Quality (TCEQ)-approved air dispersion modeling software, guidance procedures, and protocols to demonstrate acceptable air quality impacts against the National Air Ambient Quality Standards. After

[191] ETI Ex. 17 (Saxton Supp. Dir.) at 10.

[192] ETI Ex. 9 (Saxton Dir.) at 15.

[193] ETI Ex. 9 (Saxton Dir.) at 9.

construction, OCAPS' emissions sources will be tested to validate conformance with established New Source permit emissions limits.[194]

Additionally, ETI only included the planned retirement of Sabine 1 as part of the analysis for the air permit application for OCAPS submitted to TCEQ and EPA.[195] The retirement of Sabine 1 alone will offset the NOx emissions and some of the other operational emissions for the site. The planned retirements of Sabine 3 and 4 will offset an additional portion of the operational emissions for the site. The capability of OCAPS' combustion turbine equipment to be converted to 100% hydrogen operations in the future would further reduce air emissions at the site, if approved.[196]

2. Geology and Soil

Ms. Saxton explained that the construction of OCAPS will temporarily disturb approximately 75 acres of land at the existing Sabine site by physically disturbing underlying soils through the use of standard construction equipment to prepare the site for construction. ETI concedes that the physical disturbance of soils could result in soil compaction thereby reducing the porosity and conductivity of the soil; this kind of compaction could slightly increase the amount of surface runoff in the immediate area during the construction.[197] To mitigate the effects of the construction equipment on the underlying soils, ETI will use crushed aggregate

[194] ETI Ex. 9 (Saxton Dir.) at 22-23.

[195] ETI Ex. 9 (Saxton Dir.) at 9.

[196] ETI Ex. 9 (Saxton Dir.) at 9, 22-23.

[197] ETI Ex. 9 (Saxton Dir.) at 10.

base to stabilize temporary laydown areas and temporary construction roadways and to improve the existing roadway from the barge unloading area to the OCAPS facility site. ETI will also use temporary matting to avoid impact to wetland soils within the relocated transmission right-of-way east of the OCAPS facility. Ms. Saxton does not anticipate that there will be any ground disturbance outside of the 75 acres of the OCAPS site and temporary laydown areas.[198]

3. Water Resources

To address the location of OCAPS' site within flood hazard areas, ETI explains that it set the base site elevation of OCAPS at 14 feet to address 500-year flood events based on current climate models.[199] It contends that there will also be flood protection when the floodwall and levee project currently in the design and development phase by the U.S. Army Corps of Engineers (USACE) is constructed along the west, south, and east areas of the OCAPS site.[200]

ETI states that dredging activities will comply with the USACE requirements and conditions and will be considered maintenance dredging within the existing Sabine Discharge Canal and previously permitted boundaries and elevations. For the dredging activities that will occur in areas potentially used for spawning of aquatic fish species, ETI states that it will use best management practices that will allow for the least adverse effects on these resources, including matting, hydraulic dredging, and silt fencing. ETI maintains that the dredging will

[198] ETI Ex. 9 (Saxton Dir.) at 10.

[199] ETI Ex. 8 (Ruiz Dir.) at 8-10; ETI Ex. 9 (Saxton Dir.) at 11; ETI Ex. 17 (Saxton Supp. Dir.) at 12.

[200] ETI Ex. 9 (Saxton Dir.) at 11.

not cause or contribute to negative impacts to surface water quality standards and all dredge materials will be placed within an approved Dredged Material Placement Area. ETI finally states that it will comply with the applicable standards for sediment toxicity and all dredge materials will be tested prior to dredging.[201]

4. Biological Resources

The development of the EA included a review of Texas Parks and Wildlife Department's (TPWD) Texas Natural Diversity Database, which showed at the time that there were not any known occurrences of threatened and endangered species or critical habitat within the OCAPS project site. The EA showed that the Sabine property included suitable habitats for some federally protected species and state-protected species; however, no such species were observed during the multiple field surveys conducted of the OCAPS project site.[202] ETI contends that the expected impact to wildlife habitats as the result of construction will be moderate. Any protected species can avoid disturbance by relocating to adjacent minimally disturbed or undisturbed areas.[203]

ETI plans to mitigate potential disturbances to biological resources via several measures, including using existing infrastructure, siting the project primarily in previously disturbed areas, and developing a species management plan. ETI states that it will also revegetate disturbed areas of the OCAPS site that are not already planned to be developed with fill or structures that are associated with the

[201] ETI Ex. 17 (Saxton Supp. Dir.) at 10.

[202] ETI Ex. 9 (Saxton Dir.) at 13.

[203] ETI Ex. 9 (Saxton Dir.) at 13-14.

OCAPS facility. ETI will also coordinate with TCEQ so that the OCAPS wastewater discharge will meet water quality standards and effluent limitations in order to minimize potential harm and mortality of aquatic species in the vicinity of the discharge outfall.[204]

5. Environmental Impacts of Sabine 4 Extension

ETI argues that the extension of the life of Sabine 4 poses risks and costs associated with environmental compliance, as noted above (PFD Section IV.B.1.b). Sabine 4 has been derated or taken offline on numerous occasions to comply with NOx emission limitations. Additionally, as noted above, the proposed EPA rule establishing NOx emissions allowance budgets for fossil-fueled power plants would require ETI to spend $60 million on Selective Catalytic Reduction controls by 2026 to continue operating Sabine 4.[205] ETI points out that OCAPS already incorporates these controls.

The ALJs conclude that there will be minimal negative environmental impacts from the construction of OCAPS.

B. Effect on Ability to Meet Goals Established by PURA § 39.904 (P.O. Issue No. 28)

The goal of reaching 10,000 MW of installed renewable capacity for the state of Texas by January 1, 2025, as set forth in PURA section 39.904(a), has already

[204] ETI Ex. 9 (Saxton Dir.) at 14-15.

[205] ETI Ex. 29 (Weaver Reb.) at 38.

been met.[206] Therefore, OCAPS would have no effect on the ability to meet that goal.

VII. CONSIDERATION OF ALTERNATIVES TO OCAPS (P.O. ISSUE NO. 20)

ETI's 2019 Portfolio Analysis identified a 2x1 combined cycle gas turbine (CCGT) as the best option for addressing ETI's long-term planning needs. This section discusses that analysis as well as the request for proposals (RFP) which resulted in the OCAPS offer, and ETI's consideration of alternatives. Alternatives raised by several parties in the context of the subsequent Economic Evaluation are also discussed.

A. 2019 Portfolio Analysis

In 2019, ETI evaluated five resource portfolios (2019 Portfolio Analysis) across four potential future scenarios to assess portfolio performance over a range of market outcomes. The analysis also assessed transmission benefits and expected upgrades associated with locating a combined-cycle resource at different locations. The analysis produced a total supply cost and risk assessment for each portfolio in each future scenario.[207]

ETI accounted for factors beyond simple capacity expansion or economic optimization models when developing the resource portfolios, including economies of scale for CCCTs, fuel diversity, technological and locational diversity, and

[206] *See* Docket No. 52656, Order at 29 (Finding of Fact [FoF] No. 172A) (May 12, 2022); Docket No. 51480, Order at 27 (FoF No. 220) (Apr. 29, 2022); Docket No. 51912, Order at 26 (FoF No. 182) (Mar. 29, 2022).

[207] ETI Ex. 4 (Weaver Dir.) at 20, Exh. ABW-6 (Bates 22, 91-212).

supply role diversity.[208] Specifically, the technologies evaluated in the portfolios included solar, a 1x1 CCGT, a 2x1 CCGT, batteries, reciprocating engines, and delaying the retirement of Sabine 4.[209] In addition to the specific need to replace generation at Sabine, the 2019 Portfolio Analysis considered ETI's overall capacity, energy, and reliability needs; total relevant supply costs across all units and the entire service area; as well as market, fuel supply, modernization, executability, environmental, and optionality factors.[210]

TIEC faults the 2019 Portfolio Analysis for, among other things, assuming a carbon tax and failing to include a hydrogen-enabled CCGT like OCAPS.[211] These issues are addressed elsewhere in the PFD.

1. Portfolio 2 versus Portfolio 5

The two most economic portfolios were Portfolio 2 and Portfolio 5. Portfolio 2, which became OCAPS, was a 1,185 MW 2x1 CCGT located at the Sabine site with an in-service date of 2026. Portfolio 5 included a 605 MW 1x1 CCGT with an in-service date of 2026, adding 346 MW combustion turbine (CT) and 150 MW solar in 2034, and, most significantly, delaying the deactivation of the Sabine 4 to 2034.[212] No party argues that Portfolios 1, 3, or 4 are better alternatives.

[208] Sierra Club Ex. 1 (Glick Dir.) at 27 (quoting ETI response to Sierra Club RFI No. 3-33).

[209] TIEC Ex. 1 (Griffey Dir.) at 12, Fig. 1.

[210] ETI Ex. 29 (Weaver Reb.) at 25, Exh. ABW-6.

[211] ETI Ex. 4A (Weaver Dir., Conf.), Exh. ABW-8 at 1 (Bates 206 of 220).

[212] ETI Ex. 4 (Weaver Dir.), Exh. ABW-6 at 27.

ETI's analysis showed Portfolio 2 was the best option for addressing ETI's long-term planning needs. Portfolio 2 had the lowest total supply costs and most closely aligned generation and demand over the study period (through 2038), thereby reducing customer exposure to energy market price risk. Portfolio 2 was more economic than every other portfolio analyzed across every future evaluated by a range of $56 million to $320 million net present value (NPV).[213] Portfolio 2 was also comparable to Portfolios 1, 3, and 4 from a qualitative risk standpoint, while Portfolio 5 was a much riskier option from a reliability standpoint.[214]

By contrast, Portfolio 5 ranked as the worst among all portfolios in ETI's Monte Carlo analysis with regard to relative performance from a Loss of Load Expectation perspective, given its wide range of EFORd of 12-20% for Sabine 4. This range was understated because Sabine 4's average EFORd over the last five years was approximately 25% and has been as high as 35%.[215] In addition, Portfolio 5 provided considerably less energy coverage than Portfolio 2, which would significantly increase customer exposure to volatile energy market prices.[216] Further, Portfolio 5 ranked the worst among all portfolios in its effect on the average age of ETI's fleet because it is the only portfolio that deferred new generation in favor of extending Sabine 4 to 60 years.[217]

[213] ETI Ex. 29 (Weaver Reb.) at 21.

[214] ETI Ex. 4 (Weaver Dir.) at 21-22, Exh. ABW-6 at Bates 23-24, 91-212; ETI Ex. 29 (Weaver Reb.) at 21.

[215] ETI Ex. 29 (Weaver Reb.) at 18.

[216] ETI Ex. 29 (Weaver Reb.) at 17.

[217] ETI Ex. 29 (Weaver Reb.) at 18-19.

Finally, Portfolio 2 is more executable than Portfolio 5 (and the other multi-source portfolios), because there is significant risk of failure to reach commercial agreement or obtain certification for multiple resources.[218]

2. Revised Portfolio 5 versus Portfolio 2

While admitting that the 2019 Portfolio Analysis compared the 2x1 CCGT to reasonable alternative portfolios, Mr. Griffey questioned many of ETI's assumptions and opined that when properly analyzed, "Portfolio 5 is far superior to Portfolio 2."[219] In "correcting" Portfolio 5, Mr. Griffey focused on adjustments to accelerate a 1x1 CCCT to 2026 from 2034; keeping Sabine 4 in service through 2034; and adding the 2x1 CCCT in 2034 when Sabine 4 is deactivated.[220]

In response, Mr. Nguyen who is responsible for conducting the economic and financial evaluations of generation resources for ETI,[221] updated Portfolio 5 to address Mr. Griffey's adjustments and compared its total relevant supply costs to OCAPS, using the Low Gas case in the AURORA production cost model.[222] Below are the results of this update:

[218] ETI Ex. 29 (Weaver Reb.) at 18.

[219] TIEC Ex. 1 (Griffey Dir.) at 13, 16-17, 23.

[220] TIEC Ex. 1 (Griffey Dir.) at 14-17.

[221] ETI Ex. 7 (Nguyen Dir.) at 1.

[222] ETI Ex. 25 (Nguyen Reb.) at 40.

Table 1: Portfolio 2 vs. Portfolio 5 Updated (PV, 2021$ MM)

	Portfolio 2 With OCAPS	Revised Portfolio 5
Fixed Costs	$1,010	$775
Capacity Purchases	$(5)	$14
Variable Supply Cost Delta		$236
Total Relevant Cost	$1,005	$1,025

Mr. Nguyen testified that current market escalations would similarly affect Revised Portfolio 5,[223] but testified on cross examination that the escalation levels were not the same because of the economies of scale.[224]

Thus, Mr. Nguyen found that OCAPS remained more cost effective across the same range of futures used in the 2019 Portfolio Analysis than the Revised Portfolio 5, albeit by only $20 million.[225] However, Mr. Nguyen's analysis did not include a number of costs that would make OCAPS more favorable than the Revised Portfolio 5, such as: (1) an incremental $60 million associated with the cost of compliance with new environmental regulations to keep Sabine 4 in service through 2034;[226] (2) hundreds of millions of dollars in network upgrade costs associated with Mr. Griffey's less efficient use of the ability to transfer current transmission rights at the Sabine site;[227] or (3) any potential escalation of costs to

[223] ETI Ex. 25 (Nguyen Reb.) at 39.

[224] Tr. at 745-46 (Nguyen Cross).

[225] ETI Ex. 25 (Nguyen Reb.) at 40.

[226] ETI Ex. 25 (Nguyen Reb.) at 40.

[227] ETI Ex. 25 (Nguyen Reb.) at 13-14, 39-40.

extend the service life of Sabine 4, which Mr. Griffey merely assumed would be feasible.[228]

ETI points out several additional concerns with the Mr. Griffey's corrected Portfolio 5. First, extending the life of Sabine 4 until 2034 would increase transmission upgrade costs to ETI and its customers, because transferring the MISO network transmission service from Sabine 1, 3, and 4 to OCAPS requires replacement of all three units within three years of being deactivated.[229] Therefore, deactivating Sabine 1 and 3 in 2026 and extending Sabine 4 to 2034 will not allow for full transfer of the transmission rights, and ETI would have to seek incremental MISO transmission service and potentially pay significant costs associated with transmission upgrades in 2034.[230]

In addition, accelerating a 1x1 CCCT to 2026 would require extending the life of Sabine 1 and 3 to facilitate transferring transmission service and to provide reliability support while ETI conducts a market test, completes MISO transmission studies, and obtains necessary permits and authorizations ahead of construction.[231]

Finally, ETI notes that while the OCAPS cost estimate includes the fixed costs associated with hydrogen capability, Mr. Griffey did not attribute similar fixed costs to his corrected Portfolio 5, because he did not believe it to be an

[228] Tr. at 478 (Griffey Cross).

[229] ETI Ex. 29 (Weaver Reb.) at 19.

[230] ETI Ex. 29 (Weaver Reb.) at 19.

[231] ETI Ex. 29 (Weaver Reb.) at 20.

appropriate apples-to-apples comparison.[232] ETI also contends the Mr. Griffey's modified Portfolio 5 presents greater market risk than OCAPS because it affords less energy coverage.[233]

TIEC notes that Mr. Nguyen's updated analysis (Table 1, above) is based on the $1.37 billion April 2022 estimate and does not reflect the additional $210 million ETI added to the cost of OCAPS in June, which would eliminate the $20 million difference between Portfolio 2 and Portfolio 5.[234]

3. Portfolio 6

Following the selection of Portfolio 2, ETI began the RFP process (see PFD Section VII.B below). Upon selecting OCAPS from the RFP in November 2020, the RFP evaluation team initiated a further analysis which was never completed.

Specifically, in April 2021, ETI's EPG suggested that the OCAPS project be re-evaluated with current economic information in a draft PowerPoint: "Given changing circumstances across several key factors, it would be prudent to re-evaluate the OCPS resource to ensure that we are pursuing the portfolio that provides customers with the greatest benefit while balancing affordability, reliability, and policy considerations."[235] The draft further stated that "EPG is

232 Tr. at 477 (Griffey Cross).

233 ETI Ex. 25 (Nguyen Reb.) at 15.

234 TIEC Reply Brief at 38.

235 TIEC Ex. 11 (HSPM) at 3 (Bates 006).

conducting a re-evaluation of the previous portfolios considered and adding an additional portfolio(s) with renewables + peaking gas."[236]

In its second draft version, the PowerPoint listed the same original Portfolios 1-4 as well as a new Portfolio 6, which consisted of three CTs plus solar. In this draft, EPG recommended (1) assessing "any market changes that would materially impact the 2019 analyses," (2) adding "new portfolio(s) with a larger renewable position and peaking CT units (portfolio 6 and portfolio 7 with wind under development)," and (3) evaluating "all portfolios under new qualitative reliability assessment" as set out in the PowerPoint's following slides.[237] TIEC places particular significance on the EPG recommending that it would be prudent to re-evaluate OCAPS.

Mr. Nguyen (who is a part of EPG[238]) testified that the "key drivers" targeted for re-evaluations were, as both draft PowerPoints state, "resiliency based on recent experience with extreme weather events, customers and capital market emphasis on decarbonization, and state and federal policy considerations."[239] ETI explained that the purpose of the April 2021 analysis was primarily to test OCAPS against a scenario with increased levels of solar facilities that may affect LMPs. Mr. Nguyen explained that because OCAPS continued to outperform Portfolio 6 by such a wide margin, no further analysis was warranted or performed.[240]

[236] TIEC Ex. 11 (HSPM) at 3 (Bates 006).

[237] TIEC Ex. 12 (HSPM) at 8 (Bates 011).

[238] ETI Ex. 25 (Nguyen Reb.) at 37.

[239] ETI Ex. 25 (Nguyen Reb.) at 37; TIEC Ex. 11 at 3; TIEC Ex. 12 at 3.

[240] ETI Ex. 25 (Nguyen Reb.) at 37-38.

The only remaining steps of comparing OCAPS to Portfolio 6, ETI asserts, would have been a risk assessment and a execution plan.[241] However, because of the wide economic margin by which OCAPS exceeded Portfolio 6, those steps were not taken, and Portfolio 6 did not warrant further analysis.[242] The only new substantive information that would have further informed the risk assessment would have been a more recent condition assessment of Sabine 4,[243] which likely would have led to a worse score for Portfolio 5.

TIEC argues that the April 2021 assessment of Portfolio 6 shows that adding 800 MW of expensive solar to the same three CTs it used in its Economic Evaluation (see below) was more expensive than Portfolio 2.[244]

4. Updates

TIEC and Sierra Club argue that the 2019 Portfolio Analysis is stale and that ETI has not re-evaluated its alternatives, despite EPG's recommendations to do so.[245] Specifically, TIEC contends that ETI failed to update the fuel price and capacity cost assumptions and failed to update the analysis to reflect the BP22 solar additions, which impacts the economic analysis of a proposed CCGT.[246]

[241] TIEC Ex. 11 at 12-13 (Bates 15-16).

[242] ETI Ex. 25 (Nguyen Reb.) at 38; TIEC Ex. 7 at Bates 1-2 (HSPM ETI response to TIEC RFI No. 9-1).

[243] ETI Ex. 29 (Weaver Reb.) at 27-39.

[244] TIEC Reply Brief at 37.

[245] TIEC Ex. 11 (HSPM).

[246] Tr. at 406-07 (Nguyen Cross, Conf.).

ETI objects to being expected to re-analyze its portfolios, arguing it is untenable to ask a utility to perform new analyses and evaluations every time assumptions or conditions change to any degree and expect the utility to be able to execute any decisions made to add physical capacity to its portfolio. ETI asserts that, given the time required to make and execute such resource decisions, requiring a utility to conduct new analyses based on relatively minor modifications to certain inputs would result in no decisions being made or executed. It is ETI's opinion that this would prohibit new physical capacity from being built, thereby leading to a dangerous lack of generation resources.[247]

Moreover, ETI argues that it did re-run its analysis as shown above (see Table 1) and in its Economic Evaluation (see PFD Section IX.B below) and that many of the changes would not make a material difference. For example, there was no material change in forecasted gas prices from 2019 to BP21. The levelized gas price for the Low Gas price case in the 2019 Portfolio Analysis is the same as was used in the Economic Evaluation, and the Reference case price in the 2019 Portfolio Analysis was only $0.02 higher than the Economic Evaluation. The only material difference is an increase in the High Gas case ($4.87 $2019 vs $5.38 $2021), which TIEC claims is not reliable (see PFD Section IX.B.5.b).[248] ETI further argues that increasing gas prices only improves the economics of Portfolio 2, which does not require a new analysis to show. Thus, ETI argues, the decision to not further analyze reflects a prudent reallocation of resources and decision to

[247] ETI Reply Brief at 19.

[248] ETI Initial Brief at 61; ETI Ex. 7A (Nguyen Dir., Conf.), Exh. PDN-3 at 7 (Bates 39) *compare* ETI Exh. 4 (Weaver Dir.), Exh. ABW-6 at 39 (Bates 129).

move forward with a highly economic resource needed to address a significant capacity need in the 2026 timeframe.

With respect to the consideration of incremental planned solar additions, ETI notes that two of the futures of the portfolio analysis included solar additions in MISO South equivalent to ETI's current business plan assumptions.[249] Additionally, in 2021 ETI devised and analyzed Portfolio 6 to consider incremental planned solar additions, which reflects more solar resources than Portfolios 1 and 4, supported by more CT capacity.[250] ETI's preliminary economic analysis comparing OCAPS to Portfolio 6 showed that OCAPS outperformed Portfolio 6 by a wide margin.[251]

5. Cost Comparison

OPUC argues that ETI has not shown OCAPS to be an economically viable project with benefits that exceed its ever-increasing costs. OPUC notes that the cost in NPV by which Portfolio 2 exceeds the other portfolios is small—between the five portfolios, the NPV difference is 4.5% or less.[252] Portfolio 5 differed from Portfolio 2 by an average of only 1% across all futures.[253] OPUC further notes that none of the estimates account for the increasing cost of OCAPS or the hydrogen-specific costs, which makes it likely that the cost of Portfolio 2 is now higher than Portfolio 5.

[249] *See* ETI Ex. 4 (Weaver Dir.), Exh. ABW-6 at 67, 72 (Bates 157, 162).

[250] TIEC Ex. 11 at 2-3 and 9 (Bates 5-6 and 12) (HSPM ETI response to TIEC RFI No. 2-15, Addendum 1).

[251] ETI Ex. 25 (Nguyen Reb.) at 38.

[252] OPUC Ex. 1 (Nalepa Dir.) at 12.

[253] OPUC Ex. 1 (Nalepa Dir.) at 12.

ETI argues that OPUC's focus on the cost differential among the portfolios ignores reliability risk,[254] which weighs heavily against extending the life of Sabine 4.

6. Optimization

Sierra Club argues that ETI should have used the capacity expansion tools of its AURORA Capacity Expansion Model to conduct optimization modeling, as its sister utilities have done.[255] Sierra Club's witness Ms. Glick performed an optimized modeling showing that solar photovoltaic (PV) and battery storage can likely meet incremental capacity and energy needs in MISO Local Resource Zone (LRZ) 9 at a lower cost than gas, and that a combined-cycle unit is not necessary and not the lowest cost resource option in MISO LRZ 9.[256] Instead, Ms. Glick's modeling run for the MISO region selected to build approximately 1,500 MW of new solar PV and 275 MW of battery storage by 2026 but not any new combined-cycle gas resources in MISO LRZ 9 prior to 2031.[257]

ETI responds that it did not conduct optimization modeling because the AURORA capacity expansion modeling does not consider locational attributes and benefits for resources unless the model is significantly modified by the user, which is time-consuming.[258] ETI's service territory, Mr. Nguyen testified, presents

[254] Tr. at 635 (Nalepa Cross).

[255] Sierra Club Ex. 1 (Glick Dir.) at 23.

[256] Sierra Club Ex. 1 (Glick Dir.) at 42.

[257] Sierra Club Ex. 1 (Glick Dir.) at 42.

[258] Sierra Club Ex. 1 (Glick Dir.) at 23; ETI Ex. 25 (Nguyen Reb.) at 5-7.

several constraints: it is at the end of the Eastern Interconnect, bordered in part by the Gulf of Mexico, and within a load pocket that has transmission import limitations.[259] Given the constraints on ETI's system, the more efficient approach for ETI is to manually design a series of portfolios with competing technologies in a manner that already accounts for those constraints, which is how it performed the 2019 Portfolio Analysis.[260] Moreover, whatever portfolios that result from the capacity expansion model must then be further evaluated in production cost modeling to identify a least-cost portfolio, which Ms. Glick's analysis failed to do.[261]

ETI further notes that Ms. Glick used a different vendor's (EnCompass) capacity expansion model,[262] and her analysis is not comparable because it modeled MISO LRZ 9 broadly, not the unique locational constraints that exist on ETI's system.[263] This also caused the model to select an appreciable amount of wind resources, even though ETI's service territory in Southeast Texas is not an optimal location to site utility-scale wind resources.[264] ETI also notes that Ms. Glick's analysis modeled only a high gas case, which tends to favor renewable resources, and failed to test the results of her capacity expansion model with any production cost modeling.[265]

[259] ETI Ex. 25 (Nguyen Reb.) at 5.

[260] ETI Ex. 25 (Nguyen Reb.) at 5-7.

[261] ETI Ex. 25 (Nguyen Reb.) at 7-8.

[262] Sierra Club Ex. 1 (Glick Dir.) at 42-47.

[263] ETI Ex. 25 (Nguyen Reb.) at 8-9.

[264] ETI Ex. 25 (Nguyen Reb.) at 8-9.

[265] ETI Ex. 25 (Nguyen Reb.) at 8-9.

Incidentally, ETI notes that Ms. Glick's model substantiates ETI's capacity need. It selected 1,500 MW of new solar PV and 275 MW of battery storage by 2026,[266] which equates to 1,025 MW of capacity needed to meet modeled load requirements in MISO LRZ 9, assuming the solar would be accredited at 50% by MISO as an intermittent resource.[267]

7. Transmission

Several parties argue that ETI's resource need could be met through transmission. These specific arguments are addressed where raised; however, ETI provided the following general explanation as to why transmission would not serve its purpose.

ETI argues that building additional transmission to import power into ETI's service territory is not a practical or cost-effective option to address ETI's capacity and energy needs under the current circumstances presented in ETI's service territory.

ETI witness Daniel Kline, director of transmission planning for Entergy Planning Services, LLC, testified that to materially impact the import capability into the load pocket in which ETI's service territory sits, an investment of over $1 billion dollars would be required.[268] It would necessitate a long-haul transmission line, likely 500 kilovolt (kV), from across northern or eastern Louisiana into

[266] Sierra Club Ex. 1 (Glick Dir.) at 42.

[267] Tr. at 416 (Nguyen Redir.); (1,500/.5+275=1,025).

[268] Tr. at 313 (Kline Redir.).

WOTAB, and probably require additional upgrades to the transmission system within the load pocket to enable it to efficiently move the imported power.[269] By contrast, the transmission upgrades that will be required for OCAPS connectivity would cost roughly $20 million.[270]

Mr. Kline further testified that although such a transmission investment would reduce the need for additional generation in the load pocket, generation would still have to be built somewhere to meet ETI's capacity and energy needs.[271] Additionally, such transmission upgrades would not provide reactive power support that is critical to the significant industrial load that must be served in ETI's Eastern Region.[272] Mr. Kline testified that reactive power does not travel far, and it is imperative for transmission system reliability in the Eastern Region.[273]

8. Other Alternatives

Sierra Club argues that the 2019 Portfolio Analysis should have considered a more diverse set of alternatives, including, supply- or demand-side alternatives, such as incremental resources, a combination of renewable energy, battery storage, or other transmission reliability mechanisms, or wind resources, capacity purchases (short- or long-term), maintenance of Sabine Units 1 or 3, or incremental energy

[269] Tr. at 313-14 (Kline Redir.).

[270] Tr. at 314 (Kline Redir.).

[271] Tr. at 317 (Kline Recross).

[272] ETI Ex. 21 (Kline Reb.) at 6.

[273] ETI Ex. 21 (Kline Reb.) at 6; ETI Ex. 5 (Kline Dir.) at 9-10.

efficiency or demand side management, or any substantial amount of new solar PV or battery storage.[274]

Sierra Club argues that OCAPS will further skew ETI's resource portfolio in the direction of reliance on gas, which is currently 82.5% of its generation capacity.[275] Sierra Club asserts the construction of OCAPS will further commit ETI to continue to rely solely on one fuel to serve its customers for decades, creating significant cost and regulatory and reliability risk.

ETI responds that Sierra Club's arguments in favor of other resources are unfounded. Wind is not optimal in Southeast Texas.[276] PPAs from new or existing resources were solicited in the RFP, but none were proposed for ETI's consideration (discussed below).[277] Purchase capacity with no associated energy would only add to ETI's current energy price risk.[278] Maintenance of Sabine 1 and 3 was considered and rejected as an uneconomic and unreliable alternative.[279] Incremental energy efficiency and demand-side management are not viable options for meeting the capacity need. Finally, incremental solar and battery storage were included in the 2019 Portfolio Analysis, particularly in Portfolio 6.[280]

[274] Sierra Club Ex. 1 (Glick Dir.) at 28; Tr. at 299 (Kline Cross); *see also* Sierra Club Ex. 11 (ETI response to Sierra Club RFI No. 7-9).

[275] ETI Ex. 4 (Weaver Dir.) at 10, Table 1.

[276] ETI Ex. 25 (Nguyen Reb.) at 9.

[277] Tr. at 268 (Oliver Cross).

[278] ETI Ex. 4 (Weaver Dir.) at 12.

[279] ETI Ex. 4A (Weaver Dir.), Exh. ABW-7.

[280] TIEC Ex. 11 at 9 (Bates 12).

ETI further notes that Ms. Glick's own capacity expansion modeling shows a continued need for incremental gas-fired generation,[281] indicating that OCAPS can be expected to serve load throughout its useful life.

9. Analysis

The ALJs find that ETI's 2019 Portfolio Analysis reasonably determined customers' resource needs, and that the best resource to meet those needs was a 2x1 CCCT of approximately 1,200 MW located in the Eastern Region. The undisputed evidence shows that the 2019 Portfolio Analysis evaluated a range of reasonable portfolios. Although cost was one consideration, it does not account for other benefits evaluated, most significantly, risk mitigation. Reducing ETI's operating risk through the addition of a modern and efficient generating unit and achieving a high level of reliability were additional benefits of Portfolio 2, as shown by the 2019 Portfolio Analysis.[282]

Intervenors essentially ask ETI to go beyond evaluating alternatives that no party disputes are reasonable to disprove other conceivable alternatives that are detached from ETI's specific need. No party identified specific resources that address the location, capacity, capital cost, levelized cost of energy, or other critical details necessary to determine the economic and reliability impacts of the proposed alternatives. Instead, alternative proposals largely depend on transmission and extending the life of Sabine 4. As Mr. Kline testified above, and as will be further discussed elsewhere in this PFD, long distance transmission is not a viable

[281] Sierra Club Ex. 1 (Glick Dir.) at 45.

[282] ETI Ex. 4 (Weaver Dir.) at 21-22, Exh. ABW-6 (Bates 23-24, 91-212); ETI Ex. 29 (Weaver Reb.) at 21.

alternative. Moreover, Mr. Griffey's corrected Portfolio 5 was shown to have critical shortcomings. His analysis depended not only on extending the life of Sabine 4, which the ALJs find unreasonable, but also network upgrade costs and accelerating a 1x1 CCCT to 2026, which ETI has shown to be practically unfeasible. ETI could have considered any number of other alternatives, as Sierra Club urges; however, many were considered in the 2019 Portfolio Analysis, and none were shown to be practical alternatives to meet ETI's needs.

Regarding the EPG recommendation to re-evaluate the portfolios, the ALJs find TIEC's concern overstated and lacking context. First, the recommendation and analysis are contained within two draft presentations. Second, as Mr. Nguyen testified, and the face of the first draft shows, the "key drivers" targeted for re-evaluations were "resiliency based on recent experience with extreme weather events, customers and capital market emphasis on decarbonization, and state and federal policy considerations."[283] The ALJs conclude that the re-evaluation at issue concerned resiliency, decarbonization, and state and federal policy. Nothing about the draft recommendations suggests that EPG had misgivings regarding the economics or suitability of the portfolios beyond these "key drivers." The ALJs also find it imperative to note that these drafts were produced in response to a discovery request for a timeline of when ETI decided to add hydrogen firing capability to OCAPS.[284] Thus, although another draft presentation included a solar plus three CTs option in Portfolio 6, that option was abandoned in favor of the

[283] ETI Ex. 25 (Nguyen Reb.) at 37; TIEC Ex. 11 at 3; TIEC Ex. 12 at 3.

[284] TIEC Ex. 11 at Bates 2 (ETI response to TIEC RFI No. 2-15).

hydrogen option that appeared in the final presentation on May 25, 2021,[285] which ETI presumably believed addressed the key drivers raised in the original draft. TIEC's insistence that ETI failed to re-run every variable of its portfolio analysis overstates the scope of EPG's concern. TIEC's argument regarding the inadequacy of Portfolio 6 as an alternative to OCAPS only supports why that option was not further developed.

Regarding the recency of the information, the evidence shows that ETI has made multiple re-evaluations and updates, and no party has identified any parameter that might materially change the analysis that ETI did not account for. During this proceeding, ETI made periodic updates to its OCAPS cost analysis in light of market escalation, and it could not have made an update for the IRA before the hearing on the merits. The ALJs find no evidence that ETI's analysis is wanting for lack of updates or re-evaluations.

As discussed more fully below, the ALJs agree that, as identified by TIEC, some of ETI's assumptions, such as a carbon tax in the Reference and High Gas cases were unreasonable. However, those defects affect the cost analysis for each option considered and not whether the Portfolio Analysis reasonably selected the best resource option to meet ETI's particularized needs against a range of reasonable options. The ALJs find that ETI has adequately shown that the 2019 Portfolio Analysis considered a range of reasonable alternatives across a reasonable range of future conditions.

[285] ETI Ex. 4 at 24 (Weaver Dir.), Exh. ABW-8 (HSPM).

B. RFP Process

Based on the results of the 2019 Portfolio Analysis, ETI issued a request for proposal (2020 RFP) on April 28, 2020, with responses due in August 2020 for between 1,000 MW and 1,200 MW of capacity supplied from CCCT technology located in the Eastern Region[286] of ETI's service area.[287] Eligible transaction types included PPAs, tolling arrangements, asset acquisitions (existing resources), and Build-Own-Transfer asset acquisitions. The PPAs were required to be of the same size and type of resource with terms of 10 to 20 years.[288] The RFP stated that ETI, more specifically, Entergy Services, LLC (ESL),[289] intended to market test a self-build alternative as part of the RFP.[290]

In March 2020, prior to issuing the 2020 RFP, ETI held a bidders' conference, attended by three parties: two third-parties and one associated with the self-build option.[291] In April 2020, ESL issued an update that it intended to move forward with issuing the RFP in April 2020 but, in light of the COVID-pandemic, "encourag[ed] potential bidders to provide feedback on this timeline, specifically bidder's concerns on being able to effectively develop a full proposal given the current or anticipated restrictions or disruptions caused by the COVID-19

[286] The RFP identified the Eastern Region of ETI's service area as the portion of Texas encompassing an area from the Texas-Louisiana state border on the east, the Gulf of Mexico on the south, the ETI planning region known as the "Western Region" on the west, and the Southwest Power Pool on the North. ETI Ex. 14 (Oliver Dir.) at 5, n. 1.

[287] ETI Ex. 7 (Nguyen Dir.), Ex. PDN-1; ETI Ex. 4 (Weaver Dir.) at 22, 27; ETI Ex. 14 (Oliver Dir.) at 4-5.

[288] TIEC Ex. 1 (Griffey Dir.) at 29.

[289] References to ESL are used interchangeably with ETI throughout this Proposal for Decision (PFD), unless otherwise noted.

[290] ETI Ex. 14 at 5 (Oliver Dir.); ETI Ex. 3A (Rainer Dir.) at 17; ETI Ex. 4 (Weaver Dir.) at 22.

[291] ETI Ex. 14 (Oliver Dir.), Ex. WJO-3 at Bates 72.

impact."[292] In response, one potential bidder raised a question about the potential impacts of the pandemic on its ability to respond to the RFP, stating that moving the August 2020 due date out would provide a better chance to reply.[293] The deadline was not extended and, significantly, the RFP resulted in a single bid—the Entergy self-build proposal that was selected.[294]

TIEC, OPUC, and Sierra Club claim that the RFP process was flawed and overly narrow in scope. OPUC notes that because a dual fuel-fired OCAPS style plant was not considered or requested in the RFP process, it cannot be used to support the certification of OCAPS.[295] TIEC asserts that the RFP was designed to discourage participation.[296]

1. Design and Administration

ETI argues that it properly designed and administered the 2020 RFP to secure the best resource for ETI customers.[297] Ms. Weaver testified that the scope and terms and conditions of the 2020 RFP were similar to previous RFPs that garnered multiple bids, including Montgomery County Power Station (MCPS), which was certified, as well as RFPs issued by other Entergy Operating Companies.[298] To elicit solicitations, ETI provided direct notification of the 2020

[292] ETI Ex. 14 (Oliver Dir.) at Bates 72; ETI Ex. 25 (Nguyen Reb.) at 27, Exh. PDN-R-2 Bates 54 of 55, WD/PDN Testimony at Bates 121 of 136.

[293] ETI Ex. 14 (Oliver Dir.), Exh. WJO-3 at Bates 72.

[294] ETI Ex. 14 (Oliver Dir.) at 8.

[295] Reply Brief at 6.

[296] TIEC Ex. 1 (Griffey Dir.) at 39-42.

[297] ETI Ex. 29 (Weaver Reb.) at 44.

[298] ETI Ex. 29 (Weaver Reb.) at 44; ETI Ex. 25 (Nguyen Reb.) at 25.