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# Tampa Electric's Response to Staff's Sixth Data Request Nos. 1-8

TAMPA ELECTRIC COMPANY DOCKET NO. 20210034-EI STAFF'S SIXTH DATA REQUEST REQUEST NO. 1 BATES PAGES: 1 - 6 FILED: SEPTEMBER 7, 2021

1. Please provide MFR schedule A-2 for 2022, bill comparisons for typical monthly bills, comparing bills under present rates and bills under the proposed Settlement rates. The cost recovery factors for present and proposed bills should be the same currently approved factors.

A. Please see attached.

SCHEDULE A-2	LE A-2					FULL	REVENUE	FULL REVENUE REQUIREMENTS BILL COMPARISON - TYPICAL MONTHLY BILLS	NTS BILL (	COMPARISO	N - TYP	ICAL MO	THLY BIL	ST.										Page	Page 1 of 5	
FLORIDA	PUBLIC SE.	FLORIDA PUBLIC SERVICE COMMISSION	z	EXPL	ANATION	Z: For e	ach rate, cal	EXPLANATION: For each rate, calculate typical monthly bills for present rates and proposed rates.	monthly bil	lls for presen	ıt rates aı	nd propos	ed rates.								Type of	Type of data shown: XX Project	ata shown: XX Proiected Test vear Ended 12/31/2022	Ended 12/	31/2022	
COMPAN	IY: TAMPA E	COMPANY: TAMPA ELECTRIC COMPANY	<u></u>							i i	Ĺ	L										Project	Projected Prior Year Ended 12/31/2021	r Ended 12/	31/2021	
DOCKET	DOCKET No. 20210034 EI	)34 El							RS - RES	RS - RESIDENTIAL SERVICE	L SER	JGE										Historic	Historical Prior Year Ended 12/31/2020 Witness: W. R. Ashburn	- Ended 12/3 Iburn	1/2020	
æ	RATE SCHEDULE RS	JLE		BILL	UNDER	PRESE	BILL UNDER PRESENT RATES								BILL U	JNDER PR	BILL UNDER PROPOSED RATES	ATES			Z	INCREASE	COST	COSTS IN CENTS/KWH	S/KWH	
Line	(1) (2) TYPICAL	(3) BASE	(4) FUEL	(5) FCCR (	(6) CAPACITY	_ S	(7) FCRC SP	(8) SPPCRC	(9) GRT	(10) TOTAL	- 8	(11) BASE	(12) FUEL	(13) FCCR	ı	(14) CAPACITY	(15) FCRC	(16) Clean Energy	(17) v SPPCRC	(18) GRT	(19) TOTAL	(20) DOLLARS	ı	(21) (3 PERCENT PRE	PRO	(23) POSED
	KW KWH	RATE	щ		CHARGE		ш		CHARGE		íŽ	RATE	CHARGE	U			CHARGE	Trans. Mech		CHARGE		(16)-(9)			(9)/(2)*100 (16)/(	(16)/(2)*100
- 0	. 0	- \$ 15.05	\$		· \$	↔		\$	0.39	\$ 15.44	€9	21.29 \$	· &	€9	<del>\$</del> >		٠							%0:0		,
N 60	0	100 \$ 20.28	\$ 2.86 \$	0.17	\$ 0.00	<del>\$</del>	0.27 \$	0.24 \$	0.61	\$ 24.42	8	27.06 \$	2.86	€9	0.17 \$	\$ 00:0	0.27	\$ 0.44	\$ 0.24	\$ 0.80	€9	31.83 \$	7.41	30.3%	24.42	31.83
4 ro	0	250 \$ 28.11	\$ 7.14 \$	0.42	\$ 0.01	<b>↔</b>	\$ 29:0	\$ 09:0	0.95	\$ 37.89	<i></i>	35.71 \$	7.14	€9	0.42 \$	0.01	0.67	\$ 1.10	\$ 0.60	\$ 1.17	₩	46.81	8.92	23.6%	15.16	18.73
9 1	0	500 \$ 41.18	\$ 14.28 \$	0.83	\$ 0.01	÷	1.35 \$	1.20 \$	1.51	\$ 60.34	8	50.14 \$	14.28	₩	0.83 \$	0.01	1.35	\$ 2.20	\$ 1.20	\$ 1.79	€9	71.79 \$	11.45	19.0%	12.07	14.36
ထ တ	0	750 \$ 54.24	\$ 21.42 \$	1.25	\$ 0.02	<del>69</del>	2.02 \$	1.79 \$	2.07	\$ 82.80	<del>\$</del>	64.56 \$	21.42	↔	1.25 \$	0.02 \$	2.02	\$ 3.30	\$ 1.79	\$ 2.42	↔	. \$ 2.796	13.97	16.9%	11.04	12.90
2 = 9	0,1,0	1,000 \$ 67.30	\$ 28.56 \$	1.66	\$ 0.02	<del>69</del>	2.69 \$	2.39 \$	2.63	\$ 105.25	€ <del>9</del>	78.98 \$	28.56	€9	1.66 \$	0.02 \$	2.69	\$ 4.41	\$ 2.39	3.04	69	121.75 \$	16.50	15.7%	10.53	12.17
3 5	0 1,2	1,250 \$ 82.86	\$ 38.20 \$	2.08	\$ 0.03	€9	3.36 \$	2.99 \$	3.32	\$ 132.83	<i>⇔</i>	\$ 06:36	38.20	↔	2.08 \$	0.03 \$	3.36	\$ 5.51	\$ 2.99	\$ 3.80	€9	151.86 \$	19.02	14.3%	10.63	12.15
15	0 1,5	1,500 \$ 98.43	\$ 47.84 \$	2.49	\$ 0.03	e9 82	4.04 \$	3.59 \$	4.01	\$ 160.42	69	112.83 \$	47.84	↔	2.49 \$	0.03 \$	4.04	\$ 6.61	\$ 3.59	4.55	69	181.96 \$ 2	21.55	13.4%	10.69	12.13
16	0 2,0	2,000 \$ 129.55	\$ 67.12 \$	3.32	\$ 0.04	8	5.38 \$	4.78 \$	5.39	\$ 215.58	69	146.67 \$	67.12	69	3.32 \$	0.04 \$	5.38	\$ 8.81	\$ 4.78	\$ 6.05	₩	242.17 \$ .	26.59	12.3%	10.78	12.11
8 6	0 3,0	3,000 \$ 191.80	\$ 105.68 \$	4.98	\$ 0.06	<del>\$</del>	8.07 \$	7.17 \$	8.15	\$ 325.91	69	214.36 \$	105.68	69	4.98 \$	\$ 90.0	8.07	\$ 13.22	\$ 7.17	\$ 9.06	€9	362.60 \$	36.69	11.3%	10.86	12.09
20 21 22	0 5,0	5,000 \$ 316.30	\$ 182.80 \$	8.30	\$ 0.10	↔	13.45 \$	11.95 \$	13.66	\$ 546.56	69	349.74 \$	182.80	↔	8.30 \$	0.10 \$	13.45	\$ 22.03	\$ 11.95	\$ 15.09	€9	603.45 \$	56.89	10.4%	10.93	12.07
23																										
24	OOVO	TO DONATE OF CLASS		15 OF S/Bill	ENT ENT ENT ENT ENT ENT ENT ENT ENT ENT			Œ.	PROPOSED	II d/a																
26	DEMAN	DEMAND CHARGE		- 19:03	%KW				67:17	\$/KW																
27	ENERG	ENERGY CHARGE																								
29 28	- O	Over 1,000 KWH		6.225	5.225 ¢/kWH 6.225 ¢/kWH				6.769	¢/kwh																
30	FUEL OF	FUEL CHARGE																								
31	-0	0 - 1,000 KWH		3.856	¢/kWH				3.856	¢/kwh																
33	CONSE	CONSERVATION CHARGE			¢/kwh				0.166	¢/kwh																
34	CAPACI	CAPACITY CHARGE		0.002	¢/kwh				0.002	¢/kwh																
35	CLEAN	CLEAN ENERGY TRANSITION MECHANISM	ION MECHANISM	036.0	77777				0.441	¢/kWH																
37	STORM	STORM PROTECTION PLAN	ı z	0.239	¢/kwh				0.239	¢/kwh																
38																										
39	Note: F	Note: Present and proposed cost recovery clause factors are the approved January 2021 factors.	d cost recovery cla	ause factor	s are the	approve	d January 2	021 factors.																		
Supportin	g Schedules.	Supporting Schedules: E-13c, E-14 Supplement	ement																			Recab	Recap Schedules:			

SCHED	ULE A-2						IJ	FULL REVENUE F	E REQUIREME	REQUIREMENTS BILL COMPARISON - TYPICAL MONTHLY BILLS	MPARISON	- TYPICAL N	AONTHLY	BILLS										Page 2 of 5	10	
FLORIC	JA PUBL.	IC SERVICE	FLORIDA PUBLIC SERVICE COMMISSION	-	М	PLANAT	TON: For	each rate, c	EXPLANATION: For each rate, calculate typical monthly bills for present rates and proposed rates.	monthly bills	for present r	ates and pro	oosed rate:	só.							Type of data shown:	shown:	Took tool	shown: Decinated Test voor Ended 19/31/2003	2	ı
COMPA	NY: TAN	APA ELECT	COMPANY: TAMPA ELECTRIC COMPANY										!								<b>\</b>	Projected	Prior Year Er	Projected Frior Year Ended 12/31/2021	21	
DOCKE	ET No. 2	DOCKET No. 20210034 EI							) - S5	GS - GENERAL SERVICE NON-DEMAND	SERVICE	NON-DEN	JAND									Historical Witness:	Historical Prior Year End Witness: W. R. Ashburn	Historical Prior Year Ended 12/31/2020 Witness: W. R. Ashburn	0.	
	RATE SC	RATE SCHEDULE GS				OND THE	ER PRES	BILL UNDER PRESENT RATES	, so						BILL	UNDER PR	BILL UNDER PROPOSED RATES	SE			INCREASE	ASE	COSTS	COSTS IN CENTS/KWH		
:	ε,	(2)	(3)	(4)	(5)	(9)		(2)	(8)	(6)	(10)	(11)	(12)			(14)	(15)	(16)		(18)	(19)	(20)		(22)		1 4
No.	TYPICAL KW KW	KWH	BASE	FUEL	CHARGE	CAPACITY E CHARGE		CHARGE	SPPCRC	GRT CHARGE	TOTAL	BASE	FUEL		CHARGE CH	CAPACITY	CHARGE	CLEAN ENR 'RANS, MECH	SPPCRC	GRT	TOTAL	(16)-(9)	(17)/(9)	(9)/(2)*100	PROPOSED (16)/(2)*100	ے ۵
- 0	0	-	\$ 18.06	· •	+9	↔	↔		↔	0.46	\$ 18.52	\$ 22.51	€9	↔	<del>⇔</del> '	٠				\$ 0.58	\$ 23.09	69	4.56 24.6%	- %	٠	i
ν e ·	0	100	\$ 23.56	\$ 3.17	\$ 0.16	69	0.00	0.27 \$	0.25 \$	0.70	\$ 28.11	\$ 29.14	69	3.17 \$	0.16 \$	\$ 00:0	0.27	\$ 0.40	\$ 0.25	\$ 0.86 \$	34.25	69	6.14 21.9%	28.11	34.25	ί
4 10 (	0	250	\$ 31.80	\$ 7.92	\$ 0.40	69	0.01 \$	\$ 29.0	0.63 \$	1.06	\$ 42.49	\$ 39.10	<del>69</del>	7.92 \$	0.40 \$	0.01	0.67	1.01	\$ 0.63	\$ 1.28	\$ 51.00	<del>69</del>	8.51 20.0%	16.99	9 20.40	0
0 ~ 0	0	\$ 000	\$ 45.54	\$ 15.84	\$ 0.81	69	0.01 \$	1.35 \$	1.26 \$	1.66	\$ 66.45	\$ 55.68	€9	15.84 \$	0.81	0.01	1.35	\$ 2.01	\$ 1.26	\$ 1.97	\$ 78.91	69	12.46 18.8%	13.29	15.78	90
<b>.</b>	0	750	\$ 59.28	\$ 23.75	\$ 1.21	69	0.02 \$	2.02	1.88 \$	2.26	\$ 90.42	\$ 72.27	↔	23.75 \$	1.21 \$	0.02	2.02	\$ 3.02	\$ 1.88	\$ 2.67 \$	106.83	\$ 16.41	41 18.2%	12.06	3 14.24	4
9 7 9	0	1,000	\$ 73.02	\$ 31.67	\$ 1.61	69	0.02 \$	2.69 \$	2.51 \$	2.86	\$ 114.38	\$ 88.85	↔	31.67 \$	1.61 \$	0.02 \$	2.69	\$ 4.02	\$ 2.51	\$ 3.37 \$	134.74	\$ 20.36	36 17.8%	11.44	13.47	7
2 5 5	0	1,250	\$ 86.76	\$ 39.59	\$ 2.01	€9	0.03 \$	3.36 \$	3.14 \$	3.46	\$ 138.34	\$ 105.44	. \$ 39.	3.59 \$	2.01 \$	0.03 \$	3.36	\$ 5.03	\$ 3.14	\$ 4.07 \$	162.66	\$ 24.31	31 17.6%	11.07	7 13.01	-
15	0	1,500	\$ 100.50	\$ 47.51	\$ 2.42	69	0.03 \$	4.04 \$	3.77 \$	4.06	\$ 162.31	\$ 122.02	↔	47.51 \$	2.42 \$	0.03 \$	4.04	\$ 6.04	\$ 3.77	\$ 4.76 \$	\$ 190.57	\$ 28.26	26 17.4%	10.82	2 12.70	0
16	0	2,000 \$	\$ 127.98	\$ 63.34	\$ 3.22	↔	0.04 \$	5.38	5.02 \$	5.26	\$ 210.24	\$ 155.19	69	63.34 \$	3.22 \$	0.04 \$	5.38	\$ 8.05	\$ 5.02	\$ 6.16 \$	246.40	\$ 36.16	16 17.2%	10.51	12.32	2
9 9 9	0	3,000	\$ 182.94	\$ 95.01	\$ 4.83	69	\$ 90.0	8.07 \$	7.53 \$	7.65	\$ 306.09	\$ 221.53	↔	95.01 \$	4.83 \$	\$ 90.0	8.07	\$ 12.07	\$ 7.53	\$ 8.95	\$ 358.05	\$ 51.96	96 17.0%	10.20	11.94	4
2 2 8	0	2,000	\$ 292.86	\$ 158.35	\$ 8.05	69	0.10 \$	13.45 \$	12.55 \$	12.45 \$	\$ 497.81	\$ 354.21	€9	158.35 \$	8.05 \$	0.10 \$	13.45	\$ 20.12	\$ 12.55	\$ 14.53 \$	581.36	\$ 83.56	56 16.8%	96:6	3 11.63	ņ
2 2 2 2 2 2 2 2 2 2 2 2 2 2 2 2 2 2 2 2	0	8,500	485.22	\$ 269.20	\$ 13.69	69	0.17 \$	22.87 \$	21.34 \$	20.83	\$ 833.30	\$ 586.40	69	269.20 \$	13.69 \$	0.17 \$	22.87	\$ 34.20	\$ 21.34	\$ 24.30 \$	972.16	\$ 138.86	86 16.7%	8.80	11.44	4
25																										
26					PR	PRESENT					PROPOSED	SED														
27	8 6	BASIC SERVICE CH	BASIC SERVICE CHARGE		18.0	18.06 \$/Bill					22.51 \$/Bill	\$/Bill														
73	5 E	ENERGY CHARGE	RGE		5.496	6 ¢/kwh	_				6.634	¢/kwh														
30	5	FUEL CHARGE	m		3.167	7 ¢/kWH	<i>T</i>					¢/kWH														
31	ŏ 8	CONSERVATION CH	CONSERVATION CHARGE		0.161	1 ¢/kWH	<sub>I</sub> .				0.161	¢/kwH														
33 8	כ כ	FAN FNFR	CAFACII I CHARGE	SI MECHANIS			_					E KWI														
34		VIRONMEN	ENVIRONMENTAL CHARGE			0.269 ¢/kWH	æ					¢/kwh														
35	ST	ORM PRO	STORM PROTECTION PLAN	_	0.251	1 ¢/kWH	I				0.251	¢/kwh														
36																										
38	z	lote: Presen	Note: Present and proposed cost recovery clause factors are the approved January 2021 factors.	cost recovery	clause fac	tors are t	the appro	ved January	2021 factors.																	
4 5																										
Support	ting Sche	dules: E-13	Supporting Schedules: E-13c, E-14 Supplement	ment																		Recap Schedules:	chedules:			

	1					!																	Ī
FLORIDA	PUBLIC SERVI.	FLORIDA PUBLIC SERVICE COMMISSION		EXP.	EXPLANATION: For each rate, calcul	: For each	rate, calcul.	ate typical n	onthly bills fo	r present rat	late typical monthly bills for present rates and proposed rates.	ed rates.							Type of data shown:	hown:			
																			×	XX Projected Test year Ended 12/31/2022	year Ended 1	2/31/2022	
COMPAN	7: TAMPA ELEC	COMPANY: TAMPA ELECTRIC COMPANY									1								_	Projected Prior Year Ended 12/31/2021	Year Ended 1	2/31/2021	
		i						GSD	- GENERA	L SERVIC	GSD - GENERAL SERVICE DEMAND	_								Historical Prior Year Ended 12/31/2020	Year Ended 1	2/31/2020	
DOCKET	DOCKET No. 20210034 EI																			Witness: W. R. Ashburn	Ashburn		I
ž	RAIE SCHEDULE GSD			BILL	BILL UNDER PRESENT RATES	PRESENT	RATES						H	BILL UNDER PROPOSED RATES	OPOSED RA	VTES			INCREASE		COSTS IN CENTS/KWH	TS/KWH	
5		(3)	(4)	(2)	(9)	(7)	8)	.)		(10)	(11)	(12)	(13)	(14)	(12)	(16)	(17)	(18)	(18)	(20)	(21)	(22)	(23)
Line	NPIC.	BASE	_ [	W C	CAPACITY	ш Ξ	SPPCRC		GRT	TOTAL	BASE	FUEL	Ц	CAPACITY	ECRC	CLEAN ENR	SPPCRC	GRT	TOTAL	S 3	<u> </u>	± 8	PROPOSED
-		69	346.79		\$ 0.22		6	69	. 6	\$ 1.191.57	84	١.	1 _		\$ 29.02	\$ 28.61	\$ 18.40 \$	31.89 \$	1.275.51	4	%		11.65
2 75		\$ 1153.59	606.88	45.00	÷ 65	÷ 65	÷ 65				1 203 77	606.88	45.00	0.75		82.50	54.00	52.40		•	8 6 9	10.23	10.94
		\$ 1,371.09	-		÷ +9	· 69	÷ 69	54.00 \$						\$ 0.75		\$ 82.50	\$ 54.00 \$		2,680.36	\$ 15.49	%9:0	8.11	8.16
4 75		\$ 1,567.90	1,554.63		69	69	69							\$ 0.75	•	\$ 82.50	54.00	83.40		\$ (102.75)	-3.0%	6.98	6.77
S																							
9 200		69	2,311.91	100.74	69	69	69							\$ 1.46 \$		69	\$ 122.64 \$		8,252.12	\$ 483.25	6.2%	10.64	11.30
		\$ 7,520.05	4,045.84		69	69	69		322.29 \$1	\$12,891.72				\$ 2.00		\$ 550.00	360.00	344.60	13,784.19	\$ 892.47	%6:9	10.09	10.79
8 500				300.00	↔ 6	69 6	69 E		439.77 \$1	\$17,590.86			\$ 300.00	\$ 5.00		\$ 550.00	360.00	441.98			0.5%	8.03	8.07
	0 328,500	\$ 10,282.07 \$ 10,364.18		\$ 300.00		\$ 870.53	59	\$ 00.098	28.76 \$2	52,750.53	\$ 9,049.83	\$10,364.18	\$ 300.00	\$ 2.00	\$ 870.53	\$ 220.00	\$ 360.00	\$ 551.27 \$	22,050.80	\$ (699.73)	-3.1%	6.93	6.71
10		40.004	0		6		6						00	6		6		000		200	č	200	
11 2000	292,000	\$ 19,287.50 \$	9,247.04	\$ 402.96	9.00	4 //3.80	, . , .	4 440.00 \$	174.57	\$30,982.87	\$20,041.99	\$ 9,247.64	\$ 402.96	9.00	4 77.80	\$ 522.60	4 490.56 \$	\$ 822.70 \$	32,908.09	\$ 1,925.22	% Z.0	10.01	77.11
12 2000		9 6	77 742 02 6				9 6	n 6		420,070,020			00.002,1 4	00.02				1,57,5,91		\$ 5,562.US	0 0 0 0	0.0	17:01
13 2000	-		41 456 70 \$			\$ 2,321.40	A 6	e e				\$21,742.92	\$ 1,200.00	\$ 20.00	\$ 2,321.40	\$ 2,200.00		7,765.43		\$ 346.35	9.1%	8.02	90.99
4 t			7 07:00:4:1+			9 3,402.		9						20:00		00:002'Z &	4,100	76.202,2	00,102.02	(so.oo.z) ¢	?	0.92	0.70
16		_								-								_		_			
17					PRESENT								PROPOSED	OSED									
18				GSD	GSDT			GSD	GSD OPT.			GSD	GSDT	ଠା	GSD OPT.								
19	BASIC SER	BASIC SERVICE CHARGE		30.10	30.10 \$/Bill	\$/Bill			30.10 \$/Bill	<b>=</b>		32.63	32.63		32.63		\$/Bill						
20	DEMAND CHARGE	HARGE		10.92	•	\$/KW			- \$/KW	W		13.75	,	\$/KW	•		\$/KW						
21	BILLING	9			3.49	\$/KW				\$/KW			4.40	\$/KW		.,	\$/KW						
22	PEAK				7.14	7.14 \$/KW			- \$/K	\$/KW		,	8.99 \$/KW	\$/KW	,	,	\$/KW						
23	ENERGY CHARGE	HARGE		1.589	٠	¢/KWH			6.595 ¢/K	¢/KWH		0.730		¢/KWH	7.058	-	¢/KWH						
24	ON-PEAK	AK			2.908					¢/KWH			1.183	¢/KWH		•	¢/KWH						
52	OFF-PEAK	EAK			1.049					¢/KWH			<b>'</b> 0	¢/KWH		-	¢/KWH						
56	FUEL CHARGE	RGE		3.167					_	¢/KWH		3.167		¢/KWH	3.167	-	¢/KWH						
27	ON-PEAK	AK			3.335	¢/KWH				¢/KWH			3.335	¢/KWH		,,	¢/KWH						
8 8	OFF-PEAK	OFF-PEAK		, 6	3.095	¢/KWH			Y/\$ - 6	¢/KWH		' 6	3.095	¢/KWH		'	¢/KWH						
62	CONSERVATION CA	ALION CHARGE		0.00	0.00				0.130 %/R	LIVOII.		0.00	0.60	ANA P	0.130		LIVANIA						
34 30		CATACLL CHANGE	ENGLINA LI CITALI		0.0							0.0	0.01	WKW SIKW	0.002		E VANA						
- 6	CLEAN EN	CLEAN CIVENCE INCUSPINAL CHARGE	N N CO DINIGHT	200		TWO!* 3500			TANDIT BECO	74/17		1960	01:10	4//CW	102.0		TIANUTE OF THE PERSON OF THE P						
3 %	STORM PR	STORM PROTECTION PLAN		0.200		0.20 SHKWII			0.203 ¢/KWH	I M		0.500	0.20	#KW	0.500		HWW.						
8 8		CIECTON TEAN		0.72	27.0	44			0.10			0.12		A.V.A	0.100		LAAVA						
35.4	Notes:																						
36	A. The kWi	A. The kWh for each kW group is based on 20, 35, 60, and 90% load factors (LF).	up is based on 2	'0, 35, 60, a	and 90% lo	ad factors (	(LF)																
37	B. Charges	B. Charges at 20% LF are based on the GSD Option rate: 35% and 60% LF charges are	sed on the GSE	Option rate	e: 35% and	160% LF cl	haroes are	based on th	e standard ra	e: and 90%	based on the standard rate: and 90% LF charges are based on the TOD rate	e based on th	e TOD rate.										
38	C. All calcu	C. All calculations assume meter and service at secondary voltage	eter and service	at seconds	lary voltage.																		
39	D. TOD en	TOD energy charges assume 25/75 on/off-peak % for 90% LF. Peak demand to billing demand ratios are assumed to be 99% at 90% LF.	me 25/75 on/off	-peak % fo	or 90% LF.	Peak dema	and to billin	demand r	atios are assu	med to be 9	9% at 90% LF												
40	E. Present	Present and proposed cost recovery clause factors are the approved January 2021 factors.	t recovery claus	e factors ar	re the appre	oved Janus	ary 2021 fax	ctors.															
4																							
42																							
Supporting	Schedules: E-	Supporting Schedules: E-13c, E-14 Supplement	nent			Ì		]	]			]	1	1		Ì				Recap Schedules:	es:	1	

SCHEL	SCHEDULE A-2						FULL RE	FULL REVENUE REQUIREMENTS BILL COMPARISON - TYPICAL MONTHLY BILLS	ENTS BILL COM	PARISON - TY	PICAL MONT	-HLY BILLS									Page	Page 4 of 5	
FLORI	OA PUBLIC SEF	FLORIDA PUBLIC SERVICE COMMISSION		_	EXPLANATION		For each	For each rate, calculate typical monthly bills for present rates and proposed rates	monthly bills for p	resent rates an	d proposed ra	ates,							Type of data shown:	hown:			
COMP,	INY: TAMPA EL	COMPANY: TAMPA ELECTRIC COMPANY																	×	XX Projected Lest year Ended 12/31/2022 Projected Prior Year Ended 12/31/2021	ar Ended 12// ear Ended 12/	31/2021	
3	DOCKET No. 20210034 EI					ls9	DPR/GSLD	GSLDPR/GSLDTPR- GENERAL SERVICE LARGE DEMAND/ TOU/ PRIMARY SERVED	SERVICE LA	RGE DEMAI	ND/ TOU/.	PRIMARY SEF	SVED						Т.	Historical Prior Year Ended 12/31/2020	ar Ended 12/7	11/2020	
	RATE SCHEDULE	E E																				Ī	
٣	GSLDPR/GSLDTPR	Į			ILL UNDER F	BILL UNDER PRESENT RATES			-				BILL UNDER	BILL UNDER PROPOSED RATES	RATES				INCREASE		Ë.	_	ſ
	(1) (2)	(3)	(4)	(5) (6)					(11)	(12)	(13)					(18)	(19)	(20)	(21)	(22)	(23)	(24) (2	(25)
Line	TYPICAL KW KWH	BASE	ш	CCV ECCR		CAPACITY SPPCRC	CHARGE	GRT CHARGE	TOTAL	BASE	CCV	FUEL	CHARGE C	CAPACITY	CHARGE TRA	CLEAN ENR SPPCRC		GRT		DOLLARS PE	/47///01 /01//01/100/48///01/10	PRESENT FINAL	4AL
Ι.	1_	\$ 00	4.004.96	s ·	s	6	s	I.	12.471.85	80	S .	4.004.96		,	_	445.00 \$	0	~	\$ 13.435.35	64	_	9.76	10.52
2		\$ 8,615,35	6,865,65		· s	· s	· s	\$ 428.46	17,138,24	8.603.32		6,865,65	295.00 \$	5.00	573.78 \$			439.56 \$	17,582.31	444.07	2.6%		8.03
ı e		\$ 9,963.11	10,260.70	· s	s	S	S	\$ 557.42	22,296.90			10,260.70 \$	295.00 \$	5.00	\$ 29.098			561.67 \$	22,466.63 \$	169.73	%8'0		6.84
4																							
	5 1,000 255,500		8,009.93 \$	s s	590.00 \$ 1	10.00 \$ 71	710.00 \$ 669.41	3.41 \$ 620.25 \$ 755 \$ 952.75	24,809.92	\$ 14,730.73		8,009.93 \$	\$ 00.00	10.00	669.41 \$	\$ 00.008	710.00 \$	656.67 \$	26,266.73	1,456.82	5.9%	9.71	10.28
0 1-		\$ 19,795,78	20,521,40	, ,	o vo	o so		\$ 1,111,50	44,460.01	18,778,33		20,521,40	290.00	10.00	1,721,34 \$			_	44,329,29		-0.3%		6.75
6	9 5,000 1,277,500	\$ 70,479.92	40,049.63			50.00 \$ 3,550.00	s	\$ 3,087.86		123,514.45 \$ 71,298.21 \$				50.00	3,347.05 \$	4,450.00 \$	3,347.05 \$ 4,450.00 \$ 3,550.00 \$			4,	4.4%	•	10.09
10	10 5,000 2,190,000	00 \$ 84,979.54 \$	68,656.50		\$ 2,950.00 \$ 5		s ·	\$ 4,254.45		\$ 80,733.46 \$			2,950.00	50.00		4,450.00 \$	5,737.80 \$ 4,450.00 \$ 3,550.00 \$		170,387.44 \$	\$ 209.15	0.1%		7.78
Ξ ;	11 5,000 3,285,000 \$	00 \$ 98,457.13 \$	102,606.98 \$		\$ 2,950.00 \$ 5	50.00 \$ 3,550.00	s	8,606.70 \$5,544.12 \$	\$ 221,764.92	221,764.92 \$ 91,536.20 \$		\$ 102,606.98 \$	2,950.00 \$	\$ 00.09		4,450.00 \$	8,606.70 \$ 4,450.00 \$ 3,550.00 \$		5,480.76 \$ 219,230.63 \$ (2,534.29)	(2,534.29)	-1.1%	6.75	6.67
2 5				_	PRESENT					A.	PROPOSED												
4				ISS	GSD GSDT	TC				GSLDPR GSLDTPR	SSLDTPR												
15	BASIC SE	BASIC SERVICE CHARGE		13	4	130.44 S/Bill				588.86	588.86 S/Bill	III B											
16	DEMAND	DEMAND CHARGE		-		8/KW				11.50	S	\$/KW											
17	BILLING [	BILLING DEMAND				3.49 \$/KW					3.65 \$/	\$/KW											
18	PEAK DE	PEAK DEMAND CHARGE				7.14 S/KW					7.82 \$/KW	KW											
19	ENERGY	ENERGY CHARGE		-	1.589	¢kwh				1.034	12	¢/kwh											
20	4-NO	ON-PEAK			2	2.908 ¢/kWH					1.571 ¢//	¢/kwh											
21	OFF-	OFF-PEAK			-	1.049 ¢/kWH					0.840 ¢//	¢/kWH											
22	DELIVER	DELIVERY VOLTAGE CREDIT			_	(0.91) \$/KW					· S	S/KW											
23	FUEL CHARGE	ARGE		(*)	3.135	- ¢WH				3.135	· ¢/	¢/kWH											
24	4-NO	ON-PEAK				3.302 ¢/kWH					3.302 ¢//	¢/kwh											
25	OFF	OFF-PEAK			.,	3.064 ¢/kWH				,	3.064 ¢//	¢/kwh											
56	CONSER	CONSERVATION CHARGE			0.59					0.59	0.59 \$/	\$/KW											
77	CAPACI	CAFACII Y CHARGE CLEAN ENERGY TRANSITION MECHANISM	MECHANISM			0.01 \$/RW				0.0	0.0	S/KW											
28	NORINA	ENVIRONMENTAL CHARGE			0 282 0	0.262 #WWH				0.262	0.262 6/1	e/k/WH											
29	STORM F	STORM PROTECTION PLAN				0.71 \$KW				0.71	0.71 \$/	\$/KW											
30	GSLM2 C	GSLM2 CONTRACT CREDIT VALUE	ALUE			- \$/kW						S/k/V											
31																							
32	Notes:																						
33	A. The k	A. The kWh for each kW group is based on 35, 60, and 90% load factors (LF).	is based on 35, 6	0, and 90% load	id factors (LF)	L	0				7000	L											
\$ 1	B. Chark	B. Charges at 35% and 60% LF are based on standard rates and charges at 90% LF are based on 10D rates. Peak demand to belining demand ratios are assumed to be 99% at 90% LF.	- are based on star	ndard rates and	charges at	90% LF are ba	sed on TOD rate.	s. Peak demand to b	illing demand ratk	os are assumed	to be 99% at	1 90% LF.											
38	C. Calcu	C. Calculations assume meter and service at primary voltage and a power factor of 85% D. TOD enemy channes assume 25,775 on left-heak % for 90% LF.	and service at prima 25/75 on off. neat	any voltage and	a power fact.	or of 85%.																	
3 2	. п	Present and proposed cost recovery clause factors are the approved Tanuary 2021 factors	e zowery clause fact	ors are the ann	retined lange	2021 factors																	
5 88		and proposed cost	ograph ograph igo	tde ano ale co	poles paroid	1 2 2 2 2 1 IBORO18																	
8 68																							
8 4																							
5 4																							ļ

Supportin	Schedules: 1	Supporting Schedules: E-13c, E-14 Supplement	nent				i													_	Recap Schedules:			
SCHEDULE A-2	E A-2						J	LLREVENUE	REQUIREMEN	TS BILL COMF	FULL REVENUE REQUIREMENTS BILL COMPARISON - TYPICAL MONTHLY BILLS	ICAL MONT	HLY BILLS									Page	Page 5 of 5	Ī
FLORIDA	PUBLIC SER	FLORIDA PUBLIC SERVICE COMMISSION		_	EXPLANATION	: OL	Ē	each rate, calc	ulate typical mo	onthly bills for pr	For each rate, calculate typical monthly bills for present rates and proposed rates	1 proposed re	ites.							Type of data shown	data shown: XX Projected Test year Ended 12/31/2022	ar Ended 12/	1311/20122	
COMPAN	7: TAMPA ELE	COMPANY: TAMPA ELECTRIC COMPANY																		- <u>-</u>	Projected Prior Year Ended 12/31/2021	ear Ended 12/	31/2021	
						GSLE	SU/GSLDT.	SU-GENER	AL SERVIC	E LARGE D	EMAND/ TC	JU/ SUBT.	GSLDSU/GSLDTSU- GENERAL SERVICE LARGE DEMAND/ TOU/ SUBTRANSMISSION SERVED	N SERVED	_					-	Historical Prior Year Ended 12/31/2020	sar Ended 12/;	31/2020	
DOCKET	DOCKET No. 20210034 EI	14 EI																		_	Witness: W. R. Ashburn	Ashburn		
RA	RATE SCHEDULE	щ 77			REGINITER	BILL LINDER PRESENT RATES	RATES							RIII	BILL LINDER PROPOSED RATES	RATES				INCREASE		SOSTS IN CENTS/KWH	TS/KWF	
		L			1	(2)	(8)	(0)	(10)	(11)	(45)	(43)	(14)	(15)	(16)	(42)	(18)	(10)	(00)	(24)	(00)	(23)		(26)
Line	YPIC	(3) BASE	FUEL C	(5) (6) CCV ECCR		È	S	0		TOTAL	(12) BASE	(c)			(16) CAPACITY	ECRC C	N.	SPPCRC	GRT	TOTAL	DOLLARS PERCENT PRESENT	ERCENT PRE		FINAL
₹	, KWH		ш	_					CHARGE			CREDIT	ш				-		CHARGE		(16)(9)	(17)/(9) (9)/(	(9)(2)*100;16)(2)*100	(2)*100
- 5	500 127,750	0 \$ 8,483.22 \$	\$ 3,965.36 \$	\$ -	\$ 00.062	\$ 00.9	\$ 00'998	332.15 \$ 344.38 \$	344.38 \$	13,775.10	8,485.26 \$	\$ - 9	\$ 965.36 \$	290.00 \$	\$ 200.8	332.15 \$	\$ 165.00 \$	\$ 325.00 \$		348.66 \$ 13,946.43	\$ 171.32	1.2%	10.78	10.92
2 2	500 219,000	0 \$ 9,933.18 \$		- \$ 25	290.00 \$	5.00 \$	355.00 \$	569.40	\$ 460.26 \$	18,410.60	9,527.33 \$		\$ 97.767.9	290.00 \$	\$ 200.8	569.40 \$	165.00 \$			S	\$ (247.03)	-1.3%	8.41	8.29
	500 328,500	\$ 11,280.94 \$	\$ 10,156.40 \$	- \$ 25	\$ 00.062	5.00 \$		854.10	\$ 588.24 \$	23,529.68	10,774.32 \$	,	\$ 10,156.40 \$	290.00 \$	\$ 5.00 \$	854.10 \$	165.00 \$	\$ 355.00 \$	579.48	\$ 23,179.30	\$ (350.38)	-1.5%	7.16	7.06
4																								
2 1,000		s ·	7,930.72	. S	\$ 00.089	10.00	710.00 \$	\$ 664.30 \$		26,531.47	14,439.16 \$		7,930.72	\$ 00.085		664.30 \$	330.00	\$ 710.00		25,296.59	\$ (1,234.88)	-4.7%	10.38	9.90
000'1 2	00 438,000	8 18,873.09 \$	5 13,595.52 \$	36 G	\$ 00.085	10.00	710.00 \$	\$ 1,138.80 \$ 895.06	\$ 895.06 \$	35,802.47	16,523.31 \$		13,595.52 \$	\$ 00.085		10.00 \$ 1,138.80 \$	330.00	\$ 710.00 \$	1004.06 6	33,730.90	33,730.90 \$ (2,071.57)	-5.8% -5.8%	7 0.1	7.70
- 00		0.000,12	20,312,00	9	90.00	9		0.007		70'0+0'0+		,			8		00000	800			(5,210.20)	P	5.7	9
9 5,0	9 5,000 1,277,500	0 \$ 75,892.75 \$	39,653.60 \$	- \$ 2,90	30.00	\$ 2,900.00 \$ 50.00 \$ 3,550.00		\$ 3,321.50 \$ 3,214.56 \$		128,582.40	62,070.40 \$	,	\$ 39,653.60 \$	2,900.00	\$ 50.00 \$		1,650.00 \$	3,321.50 \$ 1,650.00 \$ 3,550.00 \$		2,902.45 \$ 116,097.95	\$ (12,484.46)	-9.7%	10.07	9.09
10 5,0	10 5,000 2,190,000	\$ 90,392.37 \$	\$ 09.77.60		\$ 2,900.00 \$	\$ 00.00		\$ 5,694.00 \$ 4,373.43		174,937.40			\$ 67,977.60 \$	2,900.00	50.00		5,694.00 \$ 1,650.00 \$ 3,550.00	\$ 3,550.00 \$			\$ (16,667.92)	-9.5%	7.99	7.23
11 5,000	3,285,000	3,285,000 \$ 103,869.96 \$	\$ 101,563.99 \$	- \$ 2,90	\$ 2,900.00 \$	\$ 00.09	3,550.00	8,541.00 \$ 5,653.20 \$	S	226,128.14	84,961.03 \$		\$ 101,563.99 \$	2,900.00 \$			8,541.00 \$ 1,650.00 \$ 3,550.00			5,210.66 \$ 208,426.67 \$ (17,701.47)	\$ (17,701.47)	-7.8%	6.88	6.34
12																								
13				_	PRESENT						PR	PROPOSED												
4				GSD		GSDT					esrdsu G	GSLDTSU												
15	BASIC SE	BASIC SERVICE CHARGE		56	993.27 \$	993.27 \$/Bill	3111				2,531.35 2,531.35 \$/Bill	2,531.35 \$/	.Bill											
16	DEMAND CHARGE	CHARGE		-	10.92	1/S	\$/KW				8.99	8	\$/KW											
17	BILLING DEMAND	EMAND				3.49 \$/k	\$/KW					2.86 \$/	\$/KW											
18	PEAK DEN	PEAK DEMAND CHARGE				7.14 S/K	\$/KW					6.10 \$/KW	KW											
19	ENERGY CHARGE	CHARGE		-	1.589	¢//\$	¢/k/vH				1.142	13	¢/kwh											
20	ON-PEAK	EAK				2.908 ¢/k	¢/kWH					1.375 ¢//	¢/kwh											
21	OFF-PEAK	PEAK				1.049 ¢/k	¢/kwh					1.069 ¢/kWH	KWH											
22	DELIVERY	DELIVERY VOLTAGE CREDIT					\$/KW					/s -	S/KW											
23	FUEL CHARGE	4RGE		in)	3.104		¢/k/vH				3.104	· ¢/	¢/kWH											
24	ON-PEAK	EAK					¢/kWH				,	3.268 ¢/kWH	KWH											
22	OFF-PEAK	PEAK					¢/kwh					3.033 ¢/kWH	KWH											
56	CONSERV	CONSERVATION CHARGE			0.58	0.58 \$/k	\$/KW				0.58	0.58 \$/KW	KW											
27	CAPACITY	CAPACITY CHARGE			0.01		\$/KW				0.01	0.01 \$/KW	KW											
	CLEAN EN	CLEAN ENERGY TRANSITION MECHANISM	N MECHANISM								0.33	0.33 \$/KW	KW											
28	ENVIRON	ENVIRONMENTAL CHARGE		ی	0.260	0.260 ¢/k	¢/kWH				0.260	0.260 ¢/kWH	KWH											
59	STORM PI	STORM PROTECTION PLAN			0.71	0.71 S/k	\$/KW				0.71	0.71 \$/	\$/KW											
30	GSLM2 C	GSLM2 CONTRACT CREDIT VALUE	VALUE			- \$/	S/kW					- %	S/kW											
31																								
32	Notes:																							
33	A. The kV	A. The kWh for each kW group is based on 35, 60, and 90% load factors (LF).	p is based on 35, 60,	, and 90% loac	d factors (L	Œ.																		
34	B. Charge	B. Charges at 35% and 60% LF are based on standard rates and charges at 90% LF are based on TOD rates. Peak demand to billing demand ratios are assumed to be 99% at 90% LF.	F are based on stan.	dard rates and	d charges a	t 90% LF aı	re based on TO	Drates. Peak o	emand to billin.	g demand ratio.	s are assumed;	to be 99% at	.90% LF.											
32	C. Calcult	C. Calculations assume meter and service at Subtransmission voltage and a power factor of 85%	and service at Subtra	ansmission vol.	Itage and a	power facto	r of 85%.																	
36	D. TOD e	D. TOD energy charges assume 25/75 on/off-peak % for 90% LF.	ne 25/75 on/off-peak	% for 90% LF	u'																			
37	E. Presen	Present and proposed cost recovery clause factors are the approved January 2021 factors.	recovery clause fact.	ors are the app	Jroved Janu	uary 2021 fa	ctors.																	
38																								
39																								
40																								
14	1	L																			1		I	

TAMPA ELECTRIC COMPANY DOCKET NO. 20210034-EI STAFF'S SIXTH DATA REQUEST REQUEST NO. 2 BATES PAGES: 7 - 8 FILED: SEPTEMBER 7, 2021

- **2.** Please provide an MFR schedule E-8 showing how the 2022 Settlement increase was allocated to the rate classes.
- **A.** Please see attached.

TAMPA ELECTRIC COMPANY DOCKET NO. 20210034-EI STAFF'S SIXTH DATA REQUEST FILED: SEPTEMBER 7, 2021

Type of distal above to the DOOPNIY   Thorate A Continue A Conti	Typode of automote automote and company process of service study. Provide justification for every increase from service Projected Prior Year Ended shown on Schedule E-13a, provide an explanation.  (B) C C C C C C C C C C C C C C C C C C C	posed class rates of record posed class rates of electricity does also of electricity does and from Sales of Electricity F \$ (46,355) \$ (46,355) \$ (46,355) \$ (46,355) \$ \$ (23,354) \$ \$ (23,354) \$ \$ (26,35) \$ \$ (23,354) \$ \$ (23,354) \$ \$ (26,35) \$ \$ (30,023) \$ \$ (30,023) \$ \$ (30,023) \$ \$ (46,355) \$ \$ (46,355) \$ \$ (46,355) \$ \$ (46,355) \$ \$ (46,355) \$ \$ \$ (46,355) \$ \$ \$ (46,355) \$ \$ \$ (46,355) \$ \$ \$ (46,355) \$ \$ \$ (46,355) \$ \$ \$ (46,355) \$ \$ \$ (46,355) \$ \$ \$ \$ (46,355) \$ \$ \$ \$ (46,355) \$ \$ \$ \$ (46,355) \$ \$ \$ \$ (46,355) \$ \$ \$ \$ (46,355) \$ \$ \$ \$ \$ (46,355) \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$	interney rate and interney rate class does not equal that sho more see or snot equal that sho more see in increase  (7)  (7)  (7)  (7)  (8)  (9)  (9)  (9)  (10)  (9)  (10)  (	(G) (G) (12,033) (41,824 (20.033) (12,033) (12,033) (12,041	(H) (I) Proposed COS Proposed COS Proposed COS AOR (%) Index	() DS S S S S S S S S S S S S S S S S S S	(J) Total Total Revenue Increase 16.0% -13.4% -100.0% 0.0% 22.4% 22.4%	Typ Or Jose Silvon Test Year Ended 12/31/2022 Projected Prior Year Ended 12/31/2020 Witness: W. R. Ashburn / L. J. Vogt
(A)   Present	Cost of service study Provide justification for even increase from service Projected Prior Year Ended Standard Bridge and explainance from Schedule E-13th orf the increase from Schedule E-13th provide an explainance from E-13th provide an explainance from Schedule E-13th provide an e	class not left at the sy (12/31/2008 charges by ales of electricity does increase From 1 increase From Sales and From Sales of Electricity F \$ (46,355) \$ (46,355) \$ \$ (23,354 \$ \$ 12,033 \$ \$ 5 \$ 12,033 \$ \$ 5 \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$	stem rate of return not equal that sho not equal th	if the vertual that wm on (G)	ed Reave		(J)  Total Total Revenue Increase 16.0% -13.4% -100.0% 0.0% 22.4% 22.4%	Projected Prior Year Ended 12/31/2021 Historical Prior Year Ended 12/31/2020 Witness: W. R. Ashburn / L. J. Vogt
(A) Present F (B) (B) (C) (B) (B) (B) (C) (C) (C) (C) (C) (C) (C) (C) (C) (C	Increase from service Projected Prior Year Ended Service Projected Prior Year Ended School E13b or if the increase from Schedule E-13a, provide an explanation of Prosent (C) (D) C (C) (D) C	(E)  lolars in Thousands Increase From Increase From Ser Verlages and From Sales of Electricity \$ 106,779 \$ \$ (46,355) \$ (46,355) \$ (46,355) \$ (23,354) \$ 608 \$ 608 \$ 12,033	(f)	(G)	oosed Ci ed Reve 1% 1% 1% 1% 1%		(J)  Percent Total Revenue Increase 16.0% -13.4% -100.0% 0.0% 22.4% 22.4%	Historical Pior Year Ended 12/31/2020 Witness: W. R. Ashburn / L. J. Vogt
Schedule E-13a, provide an explanation.   Schedule E-13a, provide an explanation.   C)   D    Dollars in Thousand Present COS   Present COS   Class   Serv Charges From Persent Revenues   Class   Serv Charges From Selex Charges From Persent Revenue   Proposed   Increase From Selex Charges   S(a)   C   C   C   C   C   C   C   C   C	E.13a provide an explanation.  (C) (D)  (Cass)  Class	4A 4A	(7) (2) 74 (0) (9) (9) (9) (9) (9) (9) (9) (9) (9) (9	(G) Total revenue 106,762 14,448 (46,308) (30,023) 41,824 23,348 608 608 12,033	ed Reve ed Reve 7% 7% 7% 7% 7% 1%		(J) Percent Total Revenue Increase 16.0% 21.5% -13.4% -100.0% 0.0% 22.4% 22.4% 22.3%	
Present COS   C   Dollar   E   Present COS   Present COS   Present Present COS   Present COS   Present COS   Present COS   Class   C	(C) (D)	4A 4A	(7) 74 (0) (6) (7) 8 8 8 8 8 8 8 8 8 8 8 8 8 8 8 8 8 8 8	(G) Total 106,762 11,448 (46,308) (30,023) 41,824 23,348 608 12,033 12,033	Observed CO		(J) Percent Total Increase 16.0% 21.5% -13.4% 0.0% 0.0% 22.4% 22.4%	
Present CoS         Present Revenues         Class of Charges         From Selection of Charges         Colores of Charges         From Selection of Charges <t< td=""><td>Present Class Class Charactering Class Revenue Class 1.25 \$ 66.301 \$ 1.25 \$ 66.301 \$ 1.70 \$ 30.023 \$ 1.70 \$ 53.777 \$ 2.06 \$ 53.777 \$ 2.00 \$ 56.601 \$ 1.00 \$ 1.167.433 \$ 5</td><td>norease From aleva Of Electricity 106,779 \$ 14,450 \$ (48,385) (30,023) 41,834 23,354 [20,023]</td><td>(5) 74 (0) (0) (0) (0) (0) (0) (0) (0) (0) (0)</td><td>106,762 114,448 14,1824 12,033 12,033 12,043</td><td>ed Reve ed Reve 3% 3% 3% 3% 1%</td><td></td><td>Total Total Revenue Increase 16.0% 21.5% -13.4% -100.0% 0.0% 22.4% 22.4% 22.24%</td><td></td></t<>	Present Class Class Charactering Class Revenue Class 1.25 \$ 66.301 \$ 1.25 \$ 66.301 \$ 1.70 \$ 30.023 \$ 1.70 \$ 53.777 \$ 2.06 \$ 53.777 \$ 2.00 \$ 56.601 \$ 1.00 \$ 1.167.433 \$ 5	norease From aleva Of Electricity 106,779 \$ 14,450 \$ (48,385) (30,023) 41,834 23,354 [20,023]	(5) 74 (0) (0) (0) (0) (0) (0) (0) (0) (0) (0)	106,762 114,448 14,1824 12,033 12,033 12,043	ed Reve ed Reve 3% 3% 3% 3% 1%		Total Total Revenue Increase 16.0% 21.5% -13.4% -100.0% 0.0% 22.4% 22.4% 22.24%	
Fabric Class   Fabr	Operating C Revenue 1.25 \$ 666.901 \$ 1.25 \$ 67.302 \$ 1.70 \$ 346.606 \$ 1.70 \$ 3.46.606 \$ 1.70 \$ 5.601 \$ 1.70 \$ 5.601 \$ 1.70 \$ 5.601 \$ 1.70 \$ 5.601 \$ 1.70 \$ 1	106,779 \$ 14,450 \$ (46,355) (30,023) 41,834 41,834 12,033	(c) (d) (d) (e) (e) (e) (e) (e) (e) (e) (e) (e) (e	(106,762 (46,308) (46,308) (30,023) (30,023) (1824 (23,348 (23,348 (23,348 (23,348	7%		16.0% 21.5% -13.4% 0.0% 0.0% 22.4% 22.4%	
I. GS (a)	0.88 \$ 666.901 \$ 1.25 \$ 67.302 \$ 1.04 \$ 346.606 \$ 1.070 \$ 30.023 \$ 1.070 \$ 1.0	106,779 \$ 14,450 \$ (46,365) (30,023) 41,834 23,354 [20,033] 12,033	8 8 8 8 9 8 8 8 8	106,762 14,448 (46,308) (30,023) 41,824 23,348 608 12,033 12,041	5.47% 7.66% 6.46% 0.00% 8.37% 9.40% 14.36% 14.36%	0.87 1.22 1.34 1.50 1.50 2.28	16.0% 21.5% -13.4% -100.0% 0.0% 0.0% 22.4% 22.24%	
II. GSD (c)	1.25 \$ 67.302 \$ 1.04 \$ 346.606 \$ 1.70 \$ 30.023 \$ 1.11 \$ 2.884 \$ 2.06 \$ 5.601 \$ 1.00 \$ 1.107.433 \$ 1.00 \$ 1.107.433 \$ 1.00 \$ 1.107.433 \$ 1.00 \$ 1.107.433 \$ 1.00 \$ 1.107.433 \$ 1.00 \$ 1.107.433 \$ 1.00 \$ 1.107.433 \$ 1.00 \$ 1.107.433 \$ 1.00 \$ 1.107.433 \$ 1.00 \$ 1.107.433 \$ 1.00 \$ 1.107.433 \$ 1.00 \$ 1.107.433 \$ 1.00 \$ 1.107.433 \$ 1.00 \$ 1.107.433 \$ 1.00 \$ 1.107.433 \$ 1.00 \$ 1.107.433 \$ 1.107.4	(46,355) (46,355) (30,023) 41,834 23,354 23,354 12,033 12,641		(46.308) (30.023) (30.023) 41.824 23.348 608 12.033 12.033	7.66% 6.46% 0.00% 8.37% 9.40% 14.36% 14.36%	1.22	21.5% -13.4% -100.0% 0.0% 0.0% 22.4% 22.24%	
III. GSD (c)	1.04 \$ 346,606 \$ 1.70 \$ 30,023 \$ 1.70 \$ 30,023 \$ 1.71 \$ 1.71 \$ 1.2,884 \$ 1.70 \$ 1.107			(46,308) (30,023) 41,824 23,348 608 12,033	6.46% 0.00% 8.37% 9.40% 18.03% 14.36%	1.03	-13.4% -100.0% 0.0% 22.14% 22.24%	
V. GSLDPR (c)       0.00%       -       \$       -       \$       41,834       41,834         VI. GSLDSU (c)       0.00%       -       \$       -       \$       41,834       41,834       41,834         VII. LS-1       a. Energy Service (e)       -       \$       -       \$       23,354	1.70 \$ 30.023 \$ \$ 1.11 \$ 2.884 \$ 2.00 \$ 56.01 \$ \$ 1.00 \$ 1.167.433 \$ \$ 1.00 \$ 1.167.433 \$ \$ 1.100 \$ 1.167.433 \$ \$ 1.100 \$ 1.167.433 \$ \$ 1.100			(30,023) 41,824 23,348 608 12,033	8.37% 9.40% 18.03% 14.36%	- 1.34 1.50 2.29	-100.0% 0.0% 0.0% 21.1% 22.4%	
V. GSLDPR (c)       0.00%       -       \$       41,834       411834         VI. GSLDSU (c)       0.00%       -       \$       23,364       \$       23,354         VII. LS-1       a. Energy Service (e)       4,34%       1111       \$       2,884       \$       3,492       \$       608         b. Facilities (f)       8,04%       2.06       \$       55,777       \$       65,730       \$       12,641         Total VII.a. + VII. b.       7,76%       2.00       \$       56,601       \$       69,242       \$       12,641    Total Retail	. \$ \$ \$	23 12 12 12 12 12 12 12 12 12 12 12 12 12		41,824 23,348 608 12,033	8.37% 9.40% 18.03% 14.36%	1.34	0.0% 0.0% 22.4% 22.3%	
VI. GSLDSU (c)  VII. LS-1  a. Energy Service (e)  b. Facilities (f)  Total Retail  VII. GSLDSU (c)  0.00%  - \$ 23,354 \$ 23,354  0.00%  1.11 \$ 2,884 \$ 3,492 \$ 608  1.2033  Total Retail  3.90%  1.00 \$ 56,001 \$ 69,242 \$ 12,841  Total Retail	2.06 \$ 53.777 \$ 2.00 \$ 56.601 \$ 1.00 \$ 1.167.433 \$	23 12 12	9	23,348 608 12,033 12,641	9.40%	2.29	0.0% 21.1% 22.4% 22.3%	
VII. LS-1       a. Energy Service (e)     4.34%     111     \$ 2.884     \$ 3.492     \$ 608       b. Facilities (f)     8.04%     2.06     \$ 65,777     \$ 65,777     \$ 12,033       Total VII.a. + VII. b.     7.78%     2.00     \$ 66,01     \$ 68,242     \$ 12,641       Total Retail     3.90%     1.00     \$ 1,167,433     \$ 1290,112     \$ 122671	1.11 \$ 2.884 \$ 2.06 \$ 53.777 \$ 2.00 \$ 56.601 \$ 1.00 \$ 1.167.433 \$	12		608 12,033 12,641	18.03% 14.36% 14.51%	2.29	21.1% 22.4% 22.3%	
a. Energy Service (a)  b. Facilities (f)  c. A.34%  b. Facilities (f)  8.04%  2.06  8.53.77  8.65.73  7.76%  2.00  8.56.01  8.284  8.3.492  8.12033  Total Nita. + Vit. b.  7.76%  2.00  8.56.01  8.1467.433  8.1290.112  8.126.79	1.11 \$ 2.884 \$ 2.06 \$ 53.777 \$ 2.00 \$ 56.601 \$ 1.00 \$ 1.167.433 \$ \$ 56.601 \$ 2.00 \$ 2.	12		12,033	18.03% 14.36% 14.51%	2.29	22.4%	
b. Facilities (f)     8.04%     2.06     \$ 65,750     \$ 12,033       Total VII.a. + VII. b.     7,76%     2.00     \$ 56,601     \$ 69,242     \$ 12,641       Total Rebii     3,90%     1.00     \$ 1,167,433     \$ 1,290,112     \$ 122,679	2.00 \$ 53.717 \$ \$ 2.00 \$ 1.107.433 \$ \$ 1.107.433		↔ ↔	12,033	14.36%	2.29	22.4%	
Total Retail	2.00 \$ 56,601 \$ 1.00 \$ 1		₩.	12,641	14.51%	000	22.3%	
Total Retail 3.90% 1.00 \$ 1.167.433 \$ 1.290.112 \$ 122.679	1.00 \$ 1.167.433  \$					2.32		
Total Retail 3.90% 1.00 \$ 1,167.433 \$ 1,290,112 \$ 122.679	1.00   \$ 1,167,433   \$							
23 24 25 26 27 29 29		₩	12 \$	122,691	6.26%	1.00	10.5%	
2.2 2.4 2.6 2.7 2.9 2.9								
23 25 26 27 29								
25 26 27 28 29								
26 27 28 29								
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TAMPA ELECTRIC COMPANY DOCKET NO. 20210034-EI STAFF'S SIXTH DATA REQUEST REQUEST NO. 3 BATES PAGES: 9 - 11 FILED: SEPTEMBER 7, 2021

- 3. Please state the 1,000 kilowatt hour residential bill under a) the MFR rates as originally proposed and b) under the proposed Settlement rates for 2022. Show all charges and bill components separately.
- **A.** Please see attached.

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SCHEDULE A-2	ILE A-2				π	ULL REV	/ENUE R	REQUIRE	MENTS BI	LL COMP	ARISON -	FULL REVENUE REQUIREMENTS BILL COMPARISON - TYPICAL MONTHLY BILLS	ONTHLY BI	STI											Page 1 of 5	
FLORIDA	A PUBLIC SEF	FLORIDA PUBLIC SERVICE COMMISSION	_	EXPLAN	IATION: F	or each r	rate, calcı	ulate typic	cal month	y bills for	present rat	EXPLANATION: For each rate, calculate typical monthly bills for present rates and proposed rates.	sed rates.									Type of data shown:	lata shown: XX Projected Test year Ended 12/31/2022	typer Ended	19/31/9009	
COMPAN	IY: TAMPA EL	COMPANY: TAMPA ELECTRIC COMPANY																				{	Projected Prior Year Ended 12/31/2021	r Year Ended	12/31/2021	
	F 10000000	Ē							RS-I	RESIDE	NTIAL S	RS - RESIDENTIAL SERVICE											Historical Prior Year Ended 12/31/2020	r Year Ended	12/31/2020	
DOCKE	EL NO. ZUZTUU34	34 El																					Withess: W. F	Y. Asnburn		
Ľ	ATE SCHEDU	70.5		BILLU	BILL UNDER PRESENT RATES	ESENT	RATES								BILL UP	NDER PRO	BILL UNDER PROPOSED RATES	TES				INCREASE		COSTS IN CENTS/KWH	NTS/KWH	
	(1) (2)	(3)	(4)	(2)	(9)	(2)		(8)	(6)	_	(10)	(11)	(12)	(13)				(16)			(18)	(19)	(20)	(21)	(22)	(23)
Line No.	TYPICAL KW KWH	BASE	Щ	ECCR CA CHARGE CF	CAPACITY CHARGE	ECRC	ш	SPPCRC	CHARGE		TOTAL	BASE	FUEL	ECCR : CHARGE		CAPACITY CHARGE C	ECRC	Clean Energy Trans. Mech	gy SPPCRC		GRT CHARGE	TOTAL	DOLLARS (16)-(9)	(17)/(9)	PRESENT PROPOSED (9)/(2)*100 (16)/(2)*100	PROPOSED (16)/(2)*100
	0	\$ 15.05 \$	\$	<del>\$</del>					0 \$	\$ 68.0	15.44	\$ 21.29	· •	€	€9	÷								%0.0		
N 60	0 10	100 \$ 20.28 \$	\$ 2.86 \$	0.17 \$	0.00	\$ 0.27	\$ 42	0.24	0	0.61 \$	24.42	\$ 27.06	\$ 2.86	€9	0.17 \$	0.00	0.27	\$ 0.44	8	0.24 \$	0.80	31.83	\$ 7.41	30.3%	24.42	31.83
4 0	0	250 \$ 28.11 \$	\$ 7.14 \$	0.42 \$	0.01	\$ 0.67	\$ 25	09:0	9	0.95 \$	37.89	\$ 35.71	\$ 7.14	69	0.42 \$	0.01 \$	0.67	\$ 1.10	\$ 0	\$ 09:0	1.17 \$	46.81	\$ 8.92	23.6%	15.16	18.73
9 1-	0	500 \$ 41.18 \$	\$ 14.28 \$	0.83 \$	0.01	\$ 1.35	\$ \$	1.20	€	1.51 \$	60.34	\$ 50.14	\$ 14.28	₩	0.83 \$	0.01 \$	1.35	\$ 2.20	\$	1.20 \$	1.79 \$	71.79	\$ 11.45	19.0%	12.07	14.36
	0 75	750 \$ 54.24 \$	\$ 21.42 \$	1.25 \$	0.02	\$ 2.02	\$	1.79	8	2.07 \$	82.80	\$ 64.56	\$ 21.42	↔	1.25 \$	0.02 \$	2.02	\$ 3.30	\$	1.79 \$	2.42 \$	96.77	\$ 13.97	16.9%	11.04	12.90
10 17	0 1,000	\$ 67.30	\$ 28.56 \$	1.66 \$	0.02	\$ 2.69	\$	2.39	8	2.63 \$	105.25	\$ 78.98	\$ 28.56	↔	1.66 \$	0.02 \$	2.69	\$ 4.41	\$	2.39 \$	3.04 \$	121.75	\$ 16.50	15.7%	10.53	12.17
13 13	0 1,250	\$ 82.86	\$ 38.20 \$	2.08 \$	0.03	\$ 3.36	\$	2.99	es 69	3.32 \$	132.83	\$ 95.90	\$ 38.20	↔	2.08 \$	0.03 \$	3.36	\$ 5.51	\$	2.99 \$	3.80 \$	151.86	\$ 19.02	14.3%	10.63	12.15
4 1 4	0 1,500	\$ 98.43	\$ 47.84 \$	2.49 \$	0.03	\$ 4.04	\$	3.59	4	4.01 \$	160.42	\$ 112.83	\$ 47.84	€9	2.49 \$	0.03 \$	4.04	\$ 6.61	\$	3.59 \$	4.55 \$	181.96	\$ 21.55	13.4%	10.69	12.13
17	0 2,000	\$ 129.55	\$ 67.12 \$	3.32 \$	0.04	\$ 5.38	\$	4.78	9	5.39 \$	215.58	\$ 146.67	\$ 67.12	↔	3.32 \$	0.04 \$	5.38	\$ 8.81	\$	4.78 \$	6.05 \$	242.17	\$ 26.59	12.3%	10.78	12.11
9 10 20	0 3,000	\$ 191.80	\$ 105.68 \$	4.98 \$	\$ 90.0	\$ 8.07	\$ 20	7.17	∞	8.15 \$	325.91	\$ 214.36	\$ 105.68	69	4.98 \$	\$ 90.0	8.07	\$ 13.22	8	7.17 \$	\$ 90.6	362.60	\$ 36.69	11.3%	10.86	12.09
21 2	0 5,000	\$ 316.30	\$ 182.80 \$	8.30 \$	0.10	\$ 13.45	\$	11.95	\$ 13	13.66 \$	546.56	\$ 349.74	\$ 182.80	69	8.30 \$	0.10 \$	13.45	\$ 22.03	€9	11.95 \$	15.09 \$	603.45	\$ 56.89	10.4%	10.93	12.07
23																										
24	9	0		PRESENT	⊨ <sup>i</sup>				PROPOSED																	
52	BASICS	BASIC SERVICE CHARGE		15.05 \$/BIII	*/BIII				N	21.29 \$/BIII																
27	ENERGY	ENERGY CHARGE		•	;																					
28	0 - 1	0 - 1,000 KWH		5.225 ¢/K	¢/kwh				5	5.769 ¢/kWH	Į															
29	Ove	Over 1,000 KWH		6.225 ¢/K	¢/kwh				.9	6.769 ¢/kWH	Ŧ															
31 30	FUEL CHARGE	O-1000KWH		2 856 ¢/K	#/kWH				3.0	2 856 ¢/kWH	Į															
32	Over	Over 1,000 KWH		3.856 ¢/kWH	ĭ,				iñ		Ţ															
33	CONSER	CONSERVATION CHARGE		0.166 ¢/K	¢/kwh				0	0.166 ¢/kWH	ĩ															
34	CAPACIT	CAPACITY CHARGE		0.002 ¢/K	¢/kwh				0.0	0.002 ¢/kWH	Į:															
35	CLEANE	CLEAN ENEKGY TRANSITION MECHANISM	ON MECHANISM	HWWH DSC O	ı				o c	0.441 ¢/kWH	Įį															
37	STORM	STORM PROTECTION PLAN		0.239 ¢/kWH	. I				0	0.239 ¢/kWH																
38											:															
39	Note: P	Note: Present and proposed cost recovery clause factors are the approved January 2021 factors.	cost recovery cla	ause factors a	ire the app	roved Jai	nuary 20.	21 factors	ró.																	

TAMPA ELECTRIC COMPANY DOCKET NO. 20210034-EI STAFF'S SIXTH DATA REQUEST FILED: SEPTEMBER 7, 2021

Part	FLOR	IDA PUBL	LIC SERVI	FLORIDA PUBLIC SERVICE COMMISSION	NOISSIU		EXPLA	EXPLANATION: F	For each rate,	For each rate, calculate typical monthly bills for present rates and proposed rates.	I monthly bills fo	or present rates	and proposed rate	SS.							Type of data shown:	a shown:	The state of the	00000
No.   Control	COMF	ANY: TA!	MPA ELEC	CTRIC COA	MPANY						1		!								<b>*</b>	rojected Les Projected Pric	r Year Ended 1.	2/31/2021
No. 1992   Control   Con	DOCK	ET No. 2	20210034	ѿ							XX - XE	SIDENTIAL	SEKVICE									Historical Prior Nitness: W. F	Year Ended 12 R. Ashburn	/31/2020
14   15   15   15   15   15   15   15		RATES	SCHEDUL	щ				INDER PR	ESENT RATE	v:					1 18	ORDER PRO	POSED RATE	y.			NORE	HS.	COSTSING	ENTS/KWH
This continue   Marcia   Section   Continue   Continu			(2)		.3)	(4)		(9)	(2)		(6)	(10)	(11)	(12)		(14)	(15)		(17)	(18)	(19)	(20)	(21)	(22)
1   1   1   1   1   1   1   1   1   1	Š Ė	¥	PICAL				ECCR	CAPACITY	ECRC	SPPCRC	GRT	TOTAL	BASE				ECRC	SPPCRC	GRT	TOTAL		PERCENT (17)/(9)		PROPOSED (16)/(2)*100
1	-		<u>'</u>	69		-	·	· •	· •		0.39		21.02			٠						%0.0	-	
1	0 60		10				0.17	0.00		0.24	0.61		27.62	2.86	0.17	0.00		0.24	0.80	31.95		30.9%	24.42	31.95
1	4 10 (							0.01		09:0	0.95		37.52	7.14	0.42			09:0	1.19	47.54		25.5%	15.16	19.02
1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1	9 ~ 0							0.01		1.20	1.51		54.02	14.28				1.20	1.84	73.52		21.8%	12.07	14.70
0 1,100 kg	» o ,		75					0.02		1.79	2.07		70.52	21.42	1.25			1.79	2.49	99.50		20.2%	11.04	13.27
1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1	2 7 9		1,00					0.02		2.39	2.63		87.02	28.56	1.66			2.39	3.14	125.48		19.2%	10.53	12.55
0 1500 5 100 6 1500 5 100 6 1 1500 5 100 6 1 1500 6 1100 6 1 1500 6 1 1500 6 1 1500 6 1 1500 6 1 1500 6 1 1500 6 1 1500 6 1 1500 6 1 1500 6 1 1500 6 1 1500 6 1 1500 6 1 1500 6 1 1500	13 17		1,25					0.03		2.99	3.32		106.02		2.08			2.99	3.91	156.59		17.9%	10.63	12.53
0 2000 6 1010 8 1110 8 1010 8	15							0.03		3.59	4.01		125.02		2.49			3.59	4.69	187.69		17.0%	10.69	12.51
1,000   2,000   2,015   2,01	15			€9				0.04		4.78	5.39		163.02	67.12	3.32			4.78	6.25	249.91		15.9%	10.78	12.50
1.0   1.0	19 6			€9			4.98	90:0		7.17	8.15		239.02	105.68	4.98			71.7	9.36	374.34		14.9%	10.86	12.48
BASIC SERVICE CHARGE         FRESENT         PRESENT         PROPOSED           DEMAND CHARGE         - \$KW         - \$KW         - \$KW           ENGY CHARGE         - \$KW         - \$KW         - \$KW           0 - 1,000 WH         6.225 ¢MWH         7.600 ¢WWH         7.600 ¢WWH           FLEL CHARGE         0 - 1,000 WH         2.866 ¢MWH         7.600 ¢WWH           FLEL CHARGE         0 - 1,000 WH         0 - 866 ¢WWH         7.600 ¢WWH           CONSERVITY CHARGE         0 - 166 ¢WWH         0 - 166 ¢WWH         0 - 166 ¢WWH           CAPACITY CHARGE         0 - 259 ¢WWH         0 - 166 ¢WWH         0 - 166 ¢WWH           CAPACITY CHARGE         0 - 259 ¢WWH         0 - 259 ¢WWH         0 - 259 ¢WWH           STORAIN/POTECTON PLAN         0 - 259 ¢WWH         0 - 259 ¢WWH         0 - 259 ¢WWH	21 2 2 2 2 2 2 2 2 2 2 2 2 2 2 2 2 2 2			↔_			8.30	0.10		11.95	13.66	546.56	391.02	182.80	8.30	0.10		11.95	15.58			14.0%	10.93	12.46
PAGIC SERVICE CHARGE	23							!																
DENAND CHARGE         -         \$KW         -         \$KW           FOLTOW CHARGE         -         \$LSZ6 ¢KWH         -         -         5.256 ¢KWH         -	25 25		BASICSE	RVICECH	ARGE		PRES 15.05	£N⊒ \$/Bill			PROPOSED 21.02 \$													
EVENOR CHARGE         EVENOR CHARGE         EVENOR CHARGE         EVENOR CHARGE           0 - 1000 KWH         6 225 ¢/kWH         7,800 ¢/kWH           FOLE CHARGE         2 856 ¢/kWH         2 856 ¢/kWH           OF 1,000 KWH         3 856 ¢/kWH         3 856 ¢/kWH           CONSERVATION CHARGE         0.166 ¢/kWH         0.166 ¢/kWH           CONSERVATION CHARGE         0.00 ¢/kWH         0.00 ¢/kWH           CONSERVATION CHARGE         0.266 ¢/kWH         0.00 ¢/kWH           EN IROMINITAL CHARGE         0.269 ¢/kWH         0.200 ¢/kWH           STORM PROTECTION PLAN         0.239 ¢/kWH         0.239 ¢/kWH           Note: Present and proposed cost recovery clause factors are the approved 2021 factors.         0.239 ¢/kWH	26		DEMAND	CHARGE				\$/KW				,KW												
Public Charge	27		ENERGY:	CHARGE			5.225	‡/kWH			9 99	,kWH												
FUEL CHARGE         2.866 ¢kWH         2.866 ¢kWH           0 - 1,000 kWH         3.866 ¢kWH         3.866 ¢kWH           0 - 1,000 kWH         3.866 ¢kWH         0.166 ¢kWH           CONSERVATION CHARGE         0.166 ¢kWH         0.002 ¢kWH           CONSERVATION CHARGE         0.002 ¢kWH         0.002 ¢kWH           ENVIRONIHATAL CHARGE         0.299 ¢kWH         0.290 ¢kWH           STORM PROTECTION PLAN         0.239 ¢kWH         0.239 ¢kWH           Note: Present and proposed cost recovery clause factors are the approved 2021 factors.         0.239 ¢kWH	29		Over	1,000 KWH	<b>T</b>		6.225	¢/kwH			7.600 ¢	/kwh												
0 - 1,000 kWH 2 856 ¢kWH 2 2856 ¢kWH 3 666 ¢kWH 3 666 ¢kWH 3 666 ¢kWH 6 CONSERVITOR CHARGE 0.66 ¢kWH 0.002 ¢kWH 0.002 ¢kWH CAPACITY CHARGE 0.002 ¢kWH 0.002 ¢kWH 0.002 ¢kWH 0.002 ¢kWH 0.269 ¢kWH 0.269 ¢kWH 0.269 ¢kWH 0.269 ¢kWH 0.269 ¢kWH 0.269 ¢kWH 0.260 ¢kWH 0.26	30		FUEL CHA	ARGE																				
CONSERVITOR CHRISE	31		0- 1,C	3000 KWH	7		2.856	¢/kwh				/kwh												
CAPACITY CHARGE         0.002 ¢/kWH         0.002 ¢/kWH           ENVIRONMENTAL CHARGE         0.289 ¢/kWH         0.289 ¢/kWH           STORM PROTECTION PLAN         0.239 ¢/kWH         0.239 ¢/kWH           Note: Present and proposed cost recovery clause factors are the approved 2021 factors.         0.239 ¢/kWH	33 8		CONSERV	VATION CF.	HARGE		0.166	\$/KWH			0.166 ¢	/kwH												
ENVRONMENTAL CHARGE 0.269 ¢KWH 0.299 ¢KWH STORM PROTECTION PLAN 0.299 ¢KWH 0.299 ¢KWH 0.299 ¢KWH Note: Present and proposed cost recovery clause factors are the approved 2021 factors.	34		CAPACITY	Y CHARGE	111		0.002	¢/kwH			0.002 ¢	/kwH												
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Note: Present and proposed cost recovery clause factors are the approved 2021 factors.	37		SIOKMP	KOLECIK	ON PLAN			¢kwh				/kwh												
	38		Note: Pre	esent and p	proposed cos	≭ recovery claus	e factors are	the approved	d 2021 factors.															
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- **4.** Referring to paragraph 6(d) of the Settlement, and the use of the 4 Coincident Peak (CP) methodology for allocating production and transmission plant, please respond to the following questions:
  - a. Discuss and explain why the Settlement includes the 4 CP methodology as opposed to the 12 CP and 1/13 Average Demand (AD) methodology for production as included in the original MFRs.
  - Discuss and explain why the Settlement includes the 4 CP methodology as opposed to the 12 CP methodology for transmission as included in the original MFRs.
  - c. State which three summer and which one winter month are being used to allocate production and transmission costs and explain why those particular months were chosen.
  - d. Discuss whether TECO designs and provides generation and transmission capacity needs for twelve months of the year or just four months of the year.
  - e. Are transmission costs to wholesale customers allocated on a 12 CP or 4 CP methodology? If on a 12 CP methodology, wouldn't the proposed 4 CP methodology create a mismatch between the retail and wholesale jurisdiction?
  - f. Discuss which rate classes (residential/small commercial vs. larger commercial/industrial) are negatively impacted by the proposed 4 CP methodology (when compared to the methodology used in the MFRs), by shifting target revenue requirements to the rate class away from other rate classes.
  - g. Discuss why the Settlement includes a provision that in the next general base rate proceeding, the filed cost-of-service study will use the 4 CP cost allocation.
  - h. Clarify whether in the next general base rate proceeding, TECO will only include the 4 CP cost of service methodology, or the 4CP and 12 CP and 1/13 AD methodology.
  - i. Explain who are the "Precluded Parties" and why would an affiliate of TECO oppose the 4 CP and full MDS.

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- **4a.** Discuss and explain why the Settlement includes the 4 CP methodology as opposed to the 12 CP and 1/13 Average Demand (AD) methodology for production as included in the original MFRs.
- **A.** Three preliminary points are important.

First, the cost allocation methodology that the Parties unanimously agreed upon in the 2021 Agreement was and is recognized by the Parties as reflecting costcausation on Tampa Electric's system and as reasonable for ratemaking purposes.

Second, although the 4 CP and Full MDS methodologies were used as the starting point to guide revenue allocation and rate design in the 2021 Agreement, the Parties agreed to specific rate class revenue allocations to substantially mitigate the impact of fully applying the new methodology in this case. The agreed-to revenue allocations were used with billing determinants to develop the agreed-to rates, which were reflected in the company's updated tariffs that were filed on August 20, 2021.

Third, use of the 4 CP methodology as reflected in the 2021 Agreement is best understood as part of the settlement as a whole, in light of the reasons the 12 CP and 1/13th methodology was adopted in the 1980s (which reflected key factors that determined Tampa Electric's past investments in production, transmission, and distribution plant), and in light of the fundamental theme of this rate case, namely transformation. The part of the company's transformation relevant for cost-of service purposes is the company's transition from a generation fleet dominated by baseload coal generation in the early 1980s to its current fleet that is predominantly natural gas and some solar generation with very limited coal, to a future system that over time is planned to include solar, storage, some gas, and other low-or-no-carbon fuels.

#### The Overall Settlement

Almost every settlement agreement considered and approved by the Commission reflects give and take among the parties and reflects an integrated package of exchanged agreements and consideration. The answer to why any particular provision was included in a settlement always boils down to a simple answer, namely, because the parties, notwithstanding their diverse and often competing interests, agreed to it. In virtually every settlement, every party likely would have objected to some feature(s) of the settlement if offered individually and not as a part of a larger integrated package, but nonetheless agreed to settlement in its totality. The 2021 Agreement is no different in this regard.

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### Adoption of 12 CP and 1/13th Methodology

The 12 CP and 1/13th cost-of-service methodology has been in use for approximately 40 years and was approved for Tampa Electric as early as its 1982 rate case. See Order No. 11307, Docket No. 19820007-EU, issued November 11, 1982. That order noted: "We continue to believe that the 12 CP and one - thirteenth weighted average method is the best demand allocation methodology to use in Florida. This is so because each monthly peak is important in TECO's system planning perspective when periods of peak demands and the necessary periods of planned outages are considered."

The 12 CP and 1/13th methodology was found appropriate in part because of the weather and the weather's impact, in that era, on production plant operations and expansion. At the time, Florida utilities had periods of substantial summer load (driven primarily by air conditioning) that extended from May through September that required peaking coverage but depended on long and sustained energy production from mid-morning to late evening using baseload, coal-fired generating units.

Significant winter peaks occurred sporadically between December and March when arctic cold fronts reached Florida bringing temperatures below 30 degrees. During these brief periods of cold temperatures usually occurred in the mornings when customers (primarily residential) relied on resistive heating (strip heat) or the strip heating elements of heat pumps to warm their homes, thereby creating brief periods of high demand that often exceeded the summer peak load, but usually only for a couple of hours.

The remaining shoulder months (April, May, October, and November) were considered important months for meeting peaks because of the heavy reliance on coal generating plants, which in those months were often out of service for planned maintenance and thus were not available to meet cooling-driven peak loads that occurred sporadically and infrequently in those months.

The 1/13th element of the methodology (later 25 percent) was added in part to allocate some production plant to non-firm load that was not allocated production costs for recovery in their base rates but benefitted in lower fuel cost from the coal plants that served their load.

#### Transformation Since the 1980s

The reasoning and arguments in favor of the 4 CP methodology considered by the Parties when negotiating the 2021 Agreement reflect the ongoing evolution of the company's generating fleet in the context of significant, even dramatic, advances in generating technology, equally important changes in energy policy, and the

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company's changing demand profile, all of which are part of the the fundamental theme of this proceeding, namely transformation.

From the beginning, this rate case has been about the changing energy industry, the transformation of Tampa Electric and positioning the company for a future in which renewable energy, clean energy, carbon reduction, conservation, and distributed generation will be more important.

Tampa Electric is different than it was during its 2013 rate case, and far different than it was in the early 1980s when the 12 CP and 1/13th cost-of-service methodology was approved.

In the early 1980s, the company's generating fleet was dominated by large, base-load coal-fired generating units; reduction of carbon emissions was not a major policy goal; and the Commission's efforts to promote demand-side management (energy conservation) were just beginning.

Ninety-nine percent of the company's electricity was generated using coal in 1985.

By 2013, about 59 percent of Tampa Electric's electricity was generated using coal, about 41 percent was natural gas-fired, and the company had no solar generation.

By 2020, about five percent of its electricity was generated using coal, about 89 percent was natural gas-fired, and about 6 percent was from solar.

As part of this case and as reflected in the 2021 Agreement, the company has retired three of the four coal units at Big Bend Station and the fourth runs primarily on natural gas.

With the addition of the 600 MW of Future Solar facilitated by the 2021 Agreement, nearly 14 percent of the company's energy production will be from solar by 2025, which will be enough to power more than 200,000 homes.

The company's investments in solar generation make it a leader in solar energy, promote price stability for customers, increase its fuel diversity, and contribute to the reduction of carbon emissions.

The company's generation mix changes have significantly reduced its carbon emissions, which fell from 15.7 million tons in 2013 to about 8.8 million tons in 2020. By 2023, the company expects to have reduced its carbon dioxide emissions by the equivalent of removing one million cars from local roadways.

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Since the early 1980s, the company's FPSC-approved DSM programs have reduced the need of 779 MW of summer peak demand, 1,289 MW of winter peak demand, and 1,722 GWh of annual energy. These demand and energy reductions have eliminated the need for seven – 180 MW peaking power plants along with the significant savings on fuel usage and emissions. The value of interruptible customers and demand response is now reflected in the company's Commission-approved conservation programs and the CCV credit.

The company's investment in Advanced Metering Infrastructure (AMI), also facilitated by the 2021 Agreement, will pave the way for the company to empower customers through technology via a smarter grid that delivers safe, more reliable, and affordable energy, and that will enable the company to accommodate larger amounts of company-owned and customer-owned distributed generation (including roof-top solar) and to offer enhanced demand response and other conservation programs.

The company's most recent Ten-Year Site Plan portends a future built primarily around battery storage and additional utility-scale solar, not large fossil fuel-fired generating stations. This future looks nothing like the 1980s and invites a fresh look and innovation in the cost-of-service methodology area.

#### Arguments for 4 CP

While there was lively and thoughtful discussion of the specifics of cost-of-service approaches during the settlement process, there was a shared belief among the Parties that movement toward a summer/winter approach with all production and transmission costs classified as demand-related would better reflect cost causation for Tampa Electric as it prepares for a future built on more solar, renewable and clean energy, and a greater emphasis on carbon reduction, conservation, and distributed generation. Notably, Tampa Electric proposed using a new summer/winter allocation methodology to be applied to its new solar production assets in its original filing.

Some of the ideas considered by the Parties as part of the settlement process included:

 A cost-of-service study is an analysis used to determine each rate class's responsibility for a utility's costs, so it influences the revenues a rate class generates to cover a class's cost of service. How cost is defined, which costof-service methodology is appropriate and how costs are allocated during the preparation of a cost-of-service study are issues over which reasonable people can differ.

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2. As the company has retired its coal plants, the importance of the shoulder months for base load coal-plant planned outages and cost attribution has diminished. The notion inherent in the 12 CP and 1/13th methodology that each monthly coincident peak should be given the same importance for cost-of-service purposes seems less applicable now than it was in the coal-dominated early 1980s.

- 3. Although Tampa Electric was once a consistently winter peaking utility, that has changed, in part because energy efficiency and conservation programs have improved energy efficiency, reduced customer reliance on resistive strip heating, and because recent winters have been milder, which trend is not reasonably expected to reverse. The company's most recent Ten-Year Site Plans show 3 of 4 annual peak periods occurring in the summer cooling season. Although it had not happened by the time the 2021 Agreement was filed, Tampa Electric recently experienced a new, all-time summer peak demand of 4,514 MW on August 18, 2021.
- 4. Recent history suggests that global climate change appears to be bringing hotter summers and milder winters to Florida. These changes will elevate the summer months' importance for operational planning and cost attribution purposes. Conversely, the increased reliance of solar to meet peak will increase the need to have alternative supply resources to meet the less frequent but still important winter peaks.
- 5. Although the company must plan for every month (indeed all 8,760 hours each year), its operational planning currently focuses on meeting both the heavy summer cooling months and the possibility of an occasional cold snap in the winter. The transition to a 4 CP methodology in the 2021 Agreement reflects a greater emphasis on the heavy summer cooling months and an occasional cold winter month. The company's recent new summer peak in August reinforces this idea.
- 6. Tampa Electric's Ten-Year Site Plan focuses on two system peaks for calculating reserve margin: a summer and a winter peak, and this consideration alone could support a 2CP methodology. By emphasizing the four most important monthly coincident peaks in a year, the 4 CP methodology with future innovative rate design ideas will over time move rates closer towards Tampa Electric's planning parameters, and associated cost causation, for peak demand capacity, including reserve margins, and will encourage use of the system's assets when they would be otherwise underutilized, shifting demand away from peak periods. While the Site Plan focuses on two peaks, the 2021 Agreement instead looks to 4 CP, a middle

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ground between the historical 12 CP and the summer and winter peak focus implicit in the Ten-Year Site Plan.

- 7. The industrial and large commercial customers on Tampa Electric's system tend to be high-load factor customers consistently on a year-round basis, while residential (RS) and small commercial customers (GS) tend to be very "peaky" due to their demand for summer cooling (air conditioning) and occasional winter heating (resistive strip). Indeed, it is generally recognized that residential cooling and heating drive system peaks for utilities in the southeastern United States.
- 8. The manner in which the 4 CP methodology allocates costs to the RS class may incent RS customers to install additional customer-sited solar, which would lead to more clean energy overall and will become more important for achieving global, national, and company-specific carbon reduction goals. Tampa Electric believes that additional customer-sited solar, updating the rules governing customer-sited solar, and new optional programs will be part of an overall strategy for reducing carbon emissions in the future.
- 9. Among other things, the Tampa area currently is home to steel, construction materials, furniture, electronics, and disinfectant manufacturing facilities that employ many people. Over time, application of a 4 CP cost-of-service methodology may make manufacturers and other large employers in Tampa Electric's service territory more competitive vis-à-vis other competing regions, including those that use 4 CP or a derivative thereof. The 4 CP method or variants thereof are used in Texas, Colorado, New Mexico, Oklahoma, and Arkansas, and other jurisdictions consider 4 CP as a tool to attract businesses and jobs.
- 10. The 12 CP methodology, which equally values all 12 monthly coincident peaks, does not attribute the costs of solar generation to customer classes as efficiently as the 4 CP methodology. Solar PV panels are intermittent resources that generate electricity whenever the sun is shining and have zero fuel costs relative to other resources in the order of dispatch. Solar will be in place and producing energy every day of the year including shoulder months when there may be more solar power than needed to economically meet demand. The 4 CP methodology can be viewed as a platform for future innovative pricing approaches that will more closely align incremental costs and revenues.

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- **4b.** Discuss and explain why the Settlement includes the 4 CP methodology as opposed to the 12 CP methodology for transmission as included in the original MFRs.
- As was the case for generation, the Parties agreed to the 4 CP methodology in the 2021 Agreement for transmission investment, subject to mitigation in the class revenue allocation process, as part of the overall settlement. In addition to the general considerations described above, fixed demand related costs, such as the return on transmission plant investment and fixed transmission O&M, are incurred by a utility to meet the peak demand of its customers. Once transmission investment has been constructed, their demand-related costs are fixed and do not vary with the amount of energy they carry. As a result, economic efficiency is achieved by allocating fixed demand related costs on the basis of class peak demand.
- **4c.** State which three summer and which one winter month are being used to allocate production and transmission costs and explain why those particular months were chosen.
- A. The Parties agreed to use June, July, August, and January for the 4 CP methodology employed in the 2021 Agreement. These are the four months in which peak demand was projected to be above 4,000 MW in the company's most recent Ten-Year Site Plan. Each of these months exceed 90 percent of the company's system peak demand, whereas no other month does. As noted above, Tampa Electric recently experienced a new, all-time summer peak demand of 4,514 MW on August 18, 2021.
- **4d.** Discuss whether TECO designs and provides generation and transmission capacity needs for twelve months of the year or just four months of the year.
- A. Like other utilities, Tampa Electric must be ready to provide electricity instantaneously 24 hours a day and 365 days a year, not just once a month for 12 months or once a month for four months. However, in planning to meet system demand requirements, Tampa Electric's Ten-Year Site Plans rely on a single "Winter Peak" and a single "Summer Peak" in its projections of CP demand for determining the load and resource balances explained in the response to Request 4a, above, the company's transformation away from large, baseload, coal-fired generating units and to cleaner generating resources like solar has diminished the importance of the shoulder months for operational planning and cost attribution purposes, so it is reasonable to move away from a cost-of-service methodology that values each monthly peak in a 12-month period equally. Ultimately, Tampa Electric must build sufficient capacity (both generation and transmission) to meet

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its projected peak demands, with a sufficient reserve margin to ensure reliability; because Tampa Electric experiences peaks in both the summer and the winter, Tampa Electric must plan for both. Having said that, once the capacity to meet the peak is constructed, it is available to meet all demands that occur during the year, so it is appropriate to allocate costs on the basis of the critical summer and winter peaks that drive Tampa Electric's planning and investment decisions.

- **4e.** Are transmission costs to wholesale customers allocated on a 12 CP or 4 CP methodology? If on a 12 CP methodology, wouldn't the proposed 4 CP methodology create a mismatch between the retail and wholesale jurisdiction?
- A. As specified in Paragraph 6(b)(iii) of the 2021 Agreement, retail transmission costs will be allocated to rate classes using 4 CP as mitigated. Tampa Electric's current Open Access Transmission Tariff rates uses a formula that applies a 12 CP allocation; however, Tampa Electric currently has no long-term wholesale power customers, either full or partial requirements based. In addition, Tampa Electric does not currently have any retail transmission only customers. Consequently, there is no mismatch in fact between retail and wholesale power sales.
- **4f.** Discuss which rate classes (residential/small commercial vs. larger commercial/industrial) are negatively impacted by the proposed 4 CP methodology (when compared to the methodology used in the MFRs), by shifting target revenue requirements to the rate class away from other rate classes.
- As noted in the response to 5.c., below, whether any rate class is "negatively impacted" by a particular cost allocation technique or method is relative. The company's response to Request No. 6, below, reflects a comparison of the target revenue allocations using a 12 CP and 1/13th and 50 percent MDS approach at parity to the mitigated 4 CP and 100 percent MDS approach reflected in the 2021 Agreement. However, the response to Request No. 6 does not reflect the intangible benefits associated with a transition to 4 CP, such as encouraging more customersited solar, promoting carbon reduction and economic development. It is difficult to quantify the economic value of these benefits with certainty. Additionally, as further explained in the response to Request 5(c), the 2021 Agreement reduces the residential class's increased revenue responsibility by over 20 percent, or \$38 million in just the first year of the 2021 Agreement, relative to the level proposed in the initial filing in this case. The 2021 Agreement produces a reduction of the level of increase in the rates of residential customers compared to the proposed rates.

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- **4g.** Discuss why the Settlement includes a provision that in the next general base rate proceeding, the filed cost-of-service study will use the 4 CP cost allocation.
- A. This provision reflects the general shared belief, noted in response to Request No. 4a above, that movement toward a summer/winter allocation approach, with all production and transmission costs classified as demand-related, is reasonable and appropriate for Tampa Electric in this case. Like most provisions of any settlement, the 2021 Agreement to use the 4CP methodology in Tampa Electric's next base rate case was one of a series of interrelated agreements upon which the settlement was reached and is an integral part of the fabric of the settlement. Along with the specific revenue allocation mitigation implemented in the 2021 Agreement, this provision reflects application of the principle of gradualism in this case and an expectation that the Parties, working together, will continue to "substantially and materially improve the position of all above-parity customer classes toward parity, such that costs are allocated and revenue is collected consistent with 4 CP and full MDS methods."
- **4h.** Clarify whether in the next general base rate proceeding, TECO will only include the 4 CP cost-of-service methodology, or the 4 CP and 12 CP and 1/13 AD methodology.
- A. In Tampa Electric's next base rate case filed following Docket No. 20210034-EI, the Company will file its direct case and rate design proposal reflecting a 4 CP methodology. To the extent the Commission's rules require presentation of a 12 CP and 1/13th cost-of-service study in the MFRs, the company will seek a waiver of that requirement; however, a 12 CP and 1/13th cost-of-service study could be made available if the 4 CP or full MDS methodology is opposed in the next general base rate case by an entity other than a Party to the 2021 Agreement or an affiliate of Tampa Electric.
- **4i.** Explain who are the "Precluded Parties" and why would an affiliate of TECO oppose the 4 CP and full MDS.
- A. The term "Precluded Parties" is defined in Section 6(d) at p. 25 of the 2021 Agreement and includes Tampa Electric, its affiliates, and the Consumer Parties. The term "Affiliates of Tampa Electric" was added in an abundance of caution.

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- **5.** Referring to paragraph 6(d) of the Settlement, and the use of the full Minimum Distribution System (MDS) methodology for allocating distribution plant costs, please respond to the following questions:
  - Discuss and explain why the Settlement includes the full MDS methodology as opposed to incorporating one-half of the MDS methodology as described in Witness Vogt's direct testimony on Page 26, Lines 1-18.
  - b. Explain in detail the difference between the full MDS and the one-half of the MDS methodology.
  - c. Please discuss which rate classes (residential/small commercial vs. larger commercial/industrial) are negatively impacted by the proposed full MDS methodology compared to the methodology used in the MFRS, by shifting target revenue requirements to the rate class away from other rate classes.
- **5a.** Discuss and explain why the Settlement includes the full MDS methodology as opposed to incorporating one-half of the MDS methodology as described in Witness Vogt's direct testimony on Page 26, Lines 1-18.
- A. The 2021 Agreement includes the full MDS implementation rather than half implementation for several reasons. First, it is the disposition agreed to among all of the Parties as part of their exchange of agreements and consideration. The settlement represents an extensive series of offsetting and interrelated exchanges. Every party likely would have objected to some feature of the 2021 Agreement if that feature were offered individually and not as part of a larger, integrated package, but agreed to the totality of the 2021 Agreement terms. MDS was integral to the disposition they agreed upon.

Tampa Electric's initial filing in this case, and the 2021 Agreement, use the same methodology and study to identify minimum incremental equipment and costs incurred to connect to the grid consumers having the lowest level of consumption; the only change is the full incorporation of the MDS methodology in the class cost allocation in the 2021 Agreement, which more accurately identified class cost responsibility, while recognizing that the class rate impacts are mitigated separately in the revenue allocations presented in Exhibit K to the 2021 Agreement. In other words, rather than limiting the implementation of the MDS methodology to mitigate class rate impacts, the 2021 Agreement implements the full MDS methodology for cost allocation purposes, but mitigates the class revenue allocations as part of the comprehensive agreement.

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TECO proposed to implement MDS on a 100 percent basis for costs then categorized as customer-related in its 2013 base rate case. However, in the 2013 rate case, Tampa Electric forthrightly recognized and informed the Commission that each of its proposed separations of costs between customer- and capacity-related categories, as well as the proposed MDS calculation, was "not a precise calculation." Ashburn 20130040-El Rebuttal, p. 40:20. Mr. Ashburn further noted: "the company does expect to make refinements and attempt to improve upon these calculations in the future." Id., p. 44:24-45:2. In the 2013 Settlement, participants agreed to, and the Commission approved, implementation of MDS. See Section 3(b)(i) thereof. That approach was continued in the 2017 Agreement.

Witness Vogt's testimony states that the 2021 Agreement MDS "methodology" was "accepted by the Commission in the settlement of rate and cost of service matters in the Company's 2013 retail rate case." Vogt, p. 17:2-15. In filing the 2021 base rate case, the company refined the depth at which it had conducted the 2013 study. In the 2021 analysis, Tampa Electric applied an enhanced level of granularity, to sort facilities and costs that should qualify for inclusion in customer-based rates, thereby producing a "refined" MDS allocation. Vogt, p. 24:12-13 and more generally, Vogt, pp. 20:1-25:6 and Schedule E-Rate Schedules Class Cost-of-Service Studies, Vol. II. This more detailed study, discussed at length in Tampa Electric's 2021 base rate case, reveals that the universe of equipment considered under the company's 2013 MDS study should be expanded in the interests of obtaining an accurate quantification of cost responsibility, and thus the prior categories of costs qualifying for inclusion in the MDS methodology were incomplete. The record in this case contains a more thorough, accurate assessment of costs necessary to provide the minimum level of service to any account. Evidence notes that "the refined MDS analysis stands on its own merits for full cost causation acknowledgement." Vogt, p. 26:17-18.

According to the NARUC Electric Utility Cost Allocation Manual:

When the utility installs distribution plant to provide service to a customer and to meet the individual customer's peak demand requirements, the utility must classify distribution plant data separately into demand- and customer-related costs. (NARUC Electric Utility Cost Allocation Manual, Jan. 1992, p. 90)

The full MDS methodology more accurately reflects cost causation than would a 50 percent reduction in costs classified as customer related. Nevertheless, the 2021 Agreement further mitigates the impact of cost allocation and rate design changes, so that full implementation of MDS would not occur until January 2025, at the earliest. In light of the fact that the Parties had conceptually agreed to 100

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percent implementation of MDS in 2013, but comprehensive implementation nonetheless has been deferred until 2025, its execution effectively will have been subject to a dozen years of transition.

- **5b.** Explain in detail the difference between the full MDS and the one-half of the MDS methodology.
- A. The difference between full MDS in the 2021 Agreement and half MDS embodied in the direct case in this Docket, as noted above, is not a change in methodology. In either instance, the same concept is used to classify costs as customer-related or demand-related. The only difference is that when the half MDS methodology is employed, the weighting assigned to customer-related costs for the affected distribution plant accounts (poles, lines, transformers) is reduced by 50 percent, making the proportion classified on a demand basis correspondingly greater.
- **5c.** Please discuss which rate classes (residential/small commercial vs. larger commercial/industrial) are negatively impacted by the proposed full MDS methodology compared to the methodology used in the MFRS, by shifting target revenue requirements to the rate class away from other rate classes.
- A. In general, because the full MDS method will allocate all customer-related costs on a customer basis (rather than half on a customer basis and half on a demand basis), the full MDS methodology will appropriately allocate a greater share of distribution costs to residential and small commercial customer classes than would occur if half of the MDS allocation were used. However, it is important to note that "full MDS" will not be reflected in customers' bills as a result of the 2021 Agreement. While 100 percent attribution of all MDS costs is utilized under the 2021 Agreement class cost-of-service calculations, the settlement applied mitigation to the class revenue allocations used to develop rates and as discussed in the company's response to Request No. 5a, above. Consequently, from a revenue requirements perspective "full MDS" has not been instituted during the Docket No. 20210034-EI rate period. In fact, the originally requested revenue requirements, if allocated using 12 CP and 50 percent MDS, would have increased residential class cost attribution by about \$187 million at a parity ratio of only 94 percent (see Revised Schedule E-8, p. 1, line 2, Col. G).

It should be noted that whether any rate class is "negatively impacted" by a particular cost allocation technique or method is relative. If it is accepted that the Full MDS methodology more accurately allocates costs to rate classes, then varying from that method can accurately be said to "negatively impact" the classes

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toward which cost responsibility is shifted by the half MDS method. The goal of cost allocation is widely recognized as allocating cost responsibility as closely as possible to cost causation, so that the resulting rates will provide better price signals and will also be fairer to the customers who cause and do not cause costs to be incurred.

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- 6. Please provide a comparison, using the 2022 revenue increase proposed in the Settlement, showing what target revenue requirements for each rate class would be under the cost-of-service used in the MFRs (12 CP and 1/13 AD, one-half of the MDS methodology) vs. the Settlement. Also, show the target revenue requirements difference in dollars and percent difference.
- **A.** Please see the table below for base rate impact.

Rate Class	Settlement Rev. Req. Increase (\$000)	Settlement Parity %	Settlement 12CP&1/13 Increase (\$000)	12CP &1/13 Parity %	Rev Req Diff (\$000)	Rev Req Diff (%)
RS	106,779	87	117,197	100	10,418	9.8
GS	14,450	122	3,349	100	(11,101)	(76.8)
GSD	(9,587)	103	16,826	100	26,413	275.5
GSLDPR	(1,009)	134	(509)	100	500	49.5
GSLDSU	(594)	150	(1,900)	100	(1,306)	(219.8)
LG EGY	608	288	515	100	(93)	(15.2)
LS FAC	12,033	229	(12,800)	100	(24,833)	(206.3)
TOTAL	122,680	100	122,678	100	2	(0.0)

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- 7. Please calculate and state the residential basic service charge and base energy charges if the Settlement increase for 2022 had been based on the cost-of-service methodology as used in the MFRs (12 CP and 1/13 AD, one-half of the MDS methodology).
- A. Please see attached.

Part	FLORIDA P	'UBLIC SERV	ACE COMMISSION		EXPL	NATION	: For eacl	h rate, cal-	culate typic:	al monthly!	sills for prese	nt rates a	and propo	sed rates.									Type of dai	ta shown:				
No.   Particular   Particular																							; ;	X Projecte	d Test vear	Ended 12/3	1/2022	
Column   C	COMPANY.	TAMPA ELE	CTRIC COMPANY																				<	Projecte	d Prior Year	Ended 12/3	1/2021	
1   1   1   1   1   1   1   1   1   1	DOCKETN	'o. 2021003 <sup>4</sup>	4							RS - RE	SIDENTI	IL SER	VICE											Historica	al Prior Year W.R. Ashl	Ended 12/3: ourn	/2020	
1   1   1   1   2   2   2   2   2   2	RAT	E SCHEDUL RS	ш		BILL	UNDER	PRESEN	T RATES								BILLU	NDER PR	OPOSED F	ATES				NOR	EASE	COST	S IN CENTS	ΥWH	
1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1	5		(3)	(4)		(9)	(2)			(6)	(10)		(11)	(12)	(13		(14)	(15)	(16)		7)	(18)	(19)			(2		23)
1   0   1.00   2   2.00   2   2.00   2   2.00   3   2	₹	Ē	BASE			CAPACITY	_	ш	PPCRC	GRT	TOTAL		3ASE	FUEL			PACITY 1ARGE	CHARGE	Clean Ener Trans. Med			GRT	TOTAL	DOLLA (16)-(				*OSED
1   1   1   1   1   1   1   1   1   1	-		15.05			- \$	€9				\$ 15.	44 &	21.29	•	↔	<del>\$</del>		-								%0:0		
1.   1.   1.   1.   1.   1.   1.   1.			\$ 20.28	2.86	0.17		€9				69		27.17		€9				€9			8		↔			24.42	31.94
0 1700 S 6124 S 1242 S 125 S 1051 S 125 S 1051 S 125 S 1052 S 1428 S 1051 S 125 S 1051 S 125 S 1250 S 125 S			\$ 28.11	7.14	0.42		69				69		35.98		€9				69					€9			15.16	18.84
0 1 120 6 1220 8 1222 8 1125 8 1202 8 1202 8 1202 8 1120 8 1120 8 1202			\$ 41.18	14.28	0.83		₩				69		50.68		69				↔					€9			12.07	14.47
0 1 1000 6 11000 6 11000 6 11000 6 11000 6 11000 6 11000 6 11000 6 11000 6 11000 6 11000 6 11000 6 11000 6 11000 6 11000 6 11000 6 11000			\$ 54.24	21.42	1.25		€9				\$ 82		65.37		69				69					69			49.	13.01
0 1200 6 1200 8 1020 8			\$ 67.30	28.56	1.66		₩				69		80.08		€9				₩					↔			10.53	12.29
0 1500   1900			\$ 82.86	38.20	2.08		€9				69		97.25		69				€9					69			10.63	12.26
0 2000   5 1265 5 6 712 5 332 5 0.04 5 5.38 5 4.78 5 5.39 5 15.59   5 148.83 5 67.12 5 3.22 5 0.04 5 5.39 5 4.78 5 6.15 5 7.17 5 14.83 5 6.12 5 3.22 5 0.04 5 0.05			\$ 98.43	47.84	2.49		↔				69		114.45		↔				69			29		69			69:01	12.24
0 3000   2 19180   2 191			\$ 129.55	67.12	3.32		69				69				69				69					↔			10.78	12.22
5.00   5.00			\$ 191.80	105.68	4.98		69				69		217.60		69				69					69			98:01	12.20
BASIC SERVICE CHARGE         FPRESENT         PROPOSED           DEMAND CHARGE         - \$KW         - \$KW           DEMAND CHARGE         - \$KW         - \$KW           0-1,000 KWH         5.25 ¢MWH         6.877 ¢MWH           0-1,000 KWH         6.25 ¢MWH         6.877 ¢MWH           0-1,000 KWH         2.856 ¢MWH         8.877 ¢MWH           CONSERVATION CHARGE         0.002 ¢MWH         0.002 ¢MWH           CAPACITY CHARGE         0.002 ¢MWH         0.002 ¢MWH           CLEAN HERROYTHANDITON MECHANISM         0.002 ¢MWH         0.002 ¢MWH           CLEAN HERROYTHANDITON MECHANISM         0.002 ¢MWH         0.002 ¢MWH           STORM PROTECTION PLAN         0.299 ¢MWH         0.299 ¢MWH           Nobi: Present and proposed cost recovery datase factors are the approved. January 2021 factors.         0.239 ¢MWH			\$ 316.30	182.80	8.30		69				69				69				69	69				69			0 83	12.18
BASIC SERVICE CHARGE         PRESENT         PROPOSED           DEMAND CHARGE         - \$KW         - 2129           ENERGY CHARGE         - \$KW         - 2129           0 - 1,000 KWH         5,225 ¢KWH         5,877           0 - 1,000 KWH         6,225 ¢KWH         6,877           FUEL CHARGE         0 - 1,000 KWH         3,866 ¢KWH           0 - 1,000 KWH         3,866 ¢KWH         3,866           CONSERVATION CHARGE         0,166 ¢KWH         3,866           CONSERVATION CHARGE         0,166 ¢KWH         0,166           CLEAN ENERGY TRANSITION MECHANISM         0,289 ¢KWH         0,002           CLEAN ENERGY TRANSITION MECHANISM         0,289 ¢KWH         0,289           STORM PROTECTION PLAN         0,289 ¢KWH         0,289           Nois: Present and proposed cost recovery clause fieldons are the approved January 2021 factors.         0,239											+	_																
BASIC SERVICE CHARGE         1505 \$5811         PROPOSED           DEMAND CHARGE         - \$KW         - \$129           ENERGY CHARGE         - \$KW         - \$120           0 - 1,000 KWH         5,225 ¢KWH         5,877           Over 1,000 KWH         6,225 ¢KWH         6,877           FUEL CHARGE         0 - 1,000 KWH         3,866 ¢KWH         6,877           FUEL CHARGE         0 - 1,000 KWH         3,866 ¢KWH         6,877           CONSERVATION CHARGE         0 - 166 ¢KWH         0,166 ¢KWH         0,166 ¢KWH           CAPACITY CHARGE         0,002 ¢KWH         0,002 ¢KWH         0,002 ¢KWH           CLEAN ENERGY TRANSITION MECHANISM         0,289 ¢KWH         0,289 ¢KWH         0,289 ¢KWH           ENVRONNENTAL CHARGE         0,289 ¢KWH         0,289 ¢KWH         0,289 ¢KWH         0,289 ¢KWH           Noie: Present and proposed cost recovery clause fieldons are the approved January 2021 factors.         0,289         KWH         0,289	23				1																							
DEMAND CHARGE   SKW   CHARGE   CHARGE	25	BASIC SEF	3VICE CHARGE		15,05 \$					PROPOSE 21.2	0 \$/Bill																	
EUNEROY CHARGE   EUSEN CHARGE   EUSEN CHARGE   EUNOKWH   E.225 ¢WWH   E.225 ¢WWH   E.225 ¢WWH   E.225 ¢WWH   E.225 ¢WWH   E.225 ¢WWH   E.285 ¢WWH	26	DEMAND (	CHARGE		1	\$/KW				•	\$/KW																	
0 - 1,000 KWH         5,225 ¢WWH         5,877           0 - 1,000 KWH         6,225 ¢WWH         5,877           FUEC CHARGE         2,866 ¢WWH         2,867           0 - 1,000 KWH         3,866 ¢WWH         2,886           0 - 1,000 KWH         3,866 ¢WWH         3,866           CONSERVATION CHARGE         0,002 ¢WWH         0,186           CAPACITY CHARGE         0,002 ¢WWH         0,186           CLEN BERROY TRANSTRON MECHANISM         0,269 ¢WWH         0,140           ENVONIGNITAL CHARGE         0,269 ¢WWH         0,269           STORM PROTECTION PLAN         0,289         ¢WWH         0,289           Nois: Present and proposed cost recovery clause fictions are the approved January 2021 factors.         0,289	27	ENERGY (	CHARGE																									
FUEL CHARGE   6.225 ¢WWH   6.377	58	0-1,0	000 KWH		5.225	\$/KWH				5.87																		
2.856 ¢WWH   2.866 ¢WWH   2.866 ¢WWH   2.856 ¢WWH   3.856 ¢WWH   3.8	30	Over	1,000 KWH		6.225 \$	#KWH				6.87																		
Over 1,000 KWH         3.866 ¢RWH         3.856           CONSERVATION CHARGE         0.166 ¢RWH         0.166           CAPACITY CHARGE         0.002 ¢RWH         0.166           CLEAN ERERGY TRANSITION MECHANISM         0.269 ¢RWH         0.269           ENVRONMENTAL CHARGE         0.269 ¢RWH         0.269           STORM PROTECTION PLAN         0.239 ¢RWH         0.239           Noie: Present and proposed cost recovery clause flactors are the approved January 2021 factors.         0.239	31	0-1,0	100 KWH		2.856 ¢	#KWH				2.85																		
CONSERVATION CHARGE 0.166 ¢RWH 0.166 CAPACITY CHARGE 0.002 ¢RWH 0.002 CLEAN EKERCY TRASIITION MECHANISM 0.289 ¢RWH 0.289 STORM PROTECTION PLAN 0.289 ¢RWH 0.289 STORM PROTECTION PLAN 0.289 ¢RWH 0.289 Note: Present and proposed cost recovery clause factors are the approved January 2021 factors.	32	Over 1	1,000 KWH			\$/kWH				3.85																		
CAPACITY CHARGE  CLEAN ENFECY TRANSITION MECHANISM  CLEAN ENVIRONMENTAL CARGE  0.289 ¢MWH  ENVIRONMENTAL CARGE  0.289 ¢MWH  0.289  Note: Present and proposed cost recovery clause factors are the approved January 2021 factors.	33	CONSERV	/ATION CHARGE		0.166	¢/kWH				0.16																		
CLEAN ENERGY TRANSITION MECHANISM CLEAN ENVRONMENTAL CHARGE 0.289 ¢KWH 0.239	34	CAPACITY	/ CHARGE		0.002	¢/kWH				0.00																		
ENVIKONMENTAL CHARAGE 0.259 ¢RWH 0.229 CHARAGE 0.239 ¢RWH 0.239 CHAWH 0.239 CHAWH 0.239 Note: Present and proposed cost recovery clause factors are the approved January 2021 factors.	32	CLEANEN	VERGY TRANSITIC	N MECHANISM						0.44	1 ¢/kWH																	
STORWITHOLECTION FLAN U.639 FRANT Note: Present and proposed cost recovery clause factors are the approved January 2021 factors.	36	ENVIRON	MENTAL CHARGE		0.269	#WH				0.26																		
	38	O I O	ROIECTION PLAN		0.239	E				0.25																		
	39	Note: Pre	sent and proposed	cost recovery cla	use factors	are the a	beroved,	January 2	021 factors.																			

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- 8. Referring to Exhibit K of the Settlement, please provide the same table with a column added for each year to show the increase in percent to the rate classes and explain how the GBRA year 2 and year 3 increases were allocated to the rate classes.
- **A.** Please see attached.

	2022 Adjusted	Year 1 Total	Year 2 GBRA	Year 3 GBRA	Year 2 GBRA	2023 (Year 2) Total Revenue	Year 3 GBRA	2024 (Year 3) Total Revenue
	Revenues	Increase	Increase	Increase	Increase in %	Requirement	Increase in %	Requirement
RS	\$773,680	\$149,386	\$70,116	\$16,699	%90'6	\$843,796	1.98%	\$860,495
GS	\$81,788	\$18,278	\$8,579	\$2,043	10.49%	\$90,367	2.26%	\$92,410
RS & GS Combined	\$855,468	\$167,664	\$78,695	\$18,743	9.20%	\$934,163	2.01%	\$952,906
GSD	\$300,643	\$8,996	\$4,223	\$1,006	1.40%	\$304,866	0.33%	\$305,872
GSLDPR	\$41,433	\$1,231	\$218	\$138	1.40%	\$42,011	0.33%	\$42,149
GSLDSU	\$23,350	\$694	\$326	\$78	1.40%	\$23,676	0.33%	\$23,754
LSENERGY	\$3,296	\$610	\$286	\$68	89.8	\$3,582	1.90%	\$3,650
LSFACILITIES	\$65,750	\$12,033	\$5,648	\$1,345	8.59%	\$71,398	1.88%	\$72,743
FPSC JURIS	\$1,289,940	\$191,228	\$89,755	\$21,377	%96.9	\$1,379,695	1.55%	\$1,401,072

Note 1: The Year 1 Total Increase amounts include the CETM and base revenue increase.

Note 2: The Year 2 and Year 3 GBRA allocation to rate class is based on the revenue allocation shown in the Year 1 Total Increase

Note 3: The percent increase for Year 2 is based on the 2022 Adjusted Revenues, the percent increase for Year 3 is based on the 2023 (yr 2) Total Revenue Requirement.