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SOAH DOCKET NO. 473-21-2606
PUC DOCKET NO. 52195

APPLICATION OF EL PASO ELECTRIC COMPANY TO CHANGE RATES	§ § §	BEFORE THE STATE OFFICE OF ADMINISTRATIVE HEARINGS

EL PASO ELECTRIC COMPANY'S RESPONSE TO FREEPORT-MCMORAN, INC'S FIRST REQUEST FOR INFORMATION QUESTION NOS. FMI 1-1 THROUGH FMI 1-25

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SEPTEMBER 22, 2021

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APPLICATION OF EL PASO	§	BEFORE THE STATE OFFICE
ELECTRIC COMPANY TO CHANGE	§	OF
RATES	§	ADMINISTRATIVE HEARINGS

EL PASO ELECTRIC COMPANY'S RESPONSE TO
FREEPORT-MCMORAN, INC'S FIRST REQUEST FOR INFORMATION
QUESTION NOS. FMI 1-1 THROUGH FMI 1-25

FMI 1-1:

The following Interrogatories pertains to the Direct Testimony of George Novela.

Regarding page 34, provide a complete copy of the April 2019 system loss study conducted by Management Applications Consulting, Inc., including any attachments and workpapers in "live" EXCEL format.

RESPONSE:

Please refer to Schedule O-6.3 for the system loss study.

Preparer: Eric Galvan	Title: Engineer – Associate

Sponsor: George Novela	Title: Director – Economic and Rate Research

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APPLICATION OF EL PASO ELECTRIC COMPANY TO CHANGE RATES	§ § §	BEFORE THE STATE OFFICE OF ADMINISTRATIVE HEARINGS

EL PASO ELECTRIC COMPANY'S RESPONSE TO FREEPORT-MCMORAN, INC'S FIRST REQUEST FOR INFORMATION QUESTION NOS. FMI 1-1 THROUGH FMI 1-25

FMI 1-2:

The following Interrogatories pertains to the Direct Testimony of George Novela.

Referring to Exhibit GN-6, provide the information in Excel format, with all formulas and links intact.

RESPONSE:

Please refer to FMI 1-2, Attachment 1.

Preparer:	Enedina Soto	Title:	Manager – Load Research and Data Analytics
Sponsor:	George Novela	Title:	Director – Economic and Rate Research

ENERGY (GWH)	2020 (1)	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	10-YR (7) CAGR
Native System Forecast (NFL) (2)												
Upper Bound		9,127	9,337	9,496	9,640	9,789	9,954	10,134	10,317	10,510	10,712	
Expected:	8,674	8,848	9,057	9,210	9,348	9,489	9,645	9,816	9,989	10,171	10,361	**1.8**
Lower Bound		8,568	8,776	8,925	9,055	9,188	9,336	9,498	9,661	9,831	10,009	
Less: DG (3)		37	73	104	134	164	194	224	254	283	312	
Less: EE (4)		40	81	121	161	202	242	282	323	363	403	
Plus: EV (5)		1	2	4	6	8	12	16	22	30	40	
Native System Energy												
Upper Bound		9,051	9,183	9,268	9,338	9,413	9,504	9,611	9,722	9,846	9,980	
Expected:	**8,674**	**8,772**	**8,905**	**8,989**	**9,058**	**9,131**	**9,221**	**9,325**	**9,435**	**9,555**	**9,685**	**1.1**
Lower Bound		8,492	8,627	8,710	8,777	8,849	8,937	9,040	9,147	9,264	9,390	
Total System Net Energy (6)												
Upper Bound		9,014	9,145	9,229	9,299	9,372	9,463	9,569	9,681	9,804	9,938	
Expected:	**8,507**	**8,735**	**8,868**	**8,952**	**9,021**	**9,094**	**9,184**	**9,288**	**9,398**	**9,518**	**9,648**	**1.3**
Lower Bound		8,455	8,591	8,675	8,743	8,815	8,904	9,007	9,114	9,231	9,358	
DEMAND (MW)												
Native System Forecast (NFL)												
Upper Bound		2,259	2,313	2,354	2,384	2,426	2,466	2,510	2,547	2,599	2,647	
Expected:	2,173	2,137	2,188	2,225	2,252	2,292	2,330	2,371	2,406	2,457	2,503	**1.4**
Lower Bound		2,016	2,062	2,096	2,120	2,158	2,193	2,232	2,266	2,314	2,358	
Less: DG		9	19	26	34	41	49	56	64	71	79	
Less: EE		8	15	23	31	38	46	54	62	69	77	
Plus: EV		0	1	2	3	4	6	8	11	15	20	
Native System Demand:												
Upper Bound		2,242	2,280	2,305	2,319	2,346	2,371	2,400	2,424	2,463	2,500	
Expected:	**2,173**	**2,121**	**2,155**	**2,177**	**2,190**	**2,216**	**2,240**	**2,269**	**2,292**	**2,331**	**2,367**	**0.9**
Lower Bound		1,999	2,030	2,050	2,061	2,086	2,109	2,137	2,159	2,198	2,234	
Total System Demand												
Upper Bound		2,232	2,269	2,294	2,309	2,336	2,361	2,390	2,413	2,453	2,489	
Expected:	**2,147**	**2,112**	**2,146**	**2,168**	**2,181**	**2,207**	**2,231**	**2,260**	**2,283**	**2,322**	**2,358**	**0.9**
Lower Bound		1,991	2,022	2,042	2,053	2,079	2,102	2,130	2,152	2,191	2,226	
Interruptible Load		56	56	56	56	56	56	56	56	56	56	
Upper Bound		2,176	2,211	2,235	2,248	2,274	2,299	2,327	2,350	2,390	2,426	
Expected:	**2,147**	**2,056**	**2,090**	**2,112**	**2,125**	**2,151**	**2,175**	**2,204**	**2,227**	**2,266**	**2,302**	**0.7**
Lower Bound		1,935	1,968	1,990	2,002	2,028	2,052	2,080	2,103	2,142	2,178	

Footnotes:
(1) 2020 are Actual data, Native System Peak occurred on July 13.
(2) Net For Load is forecasted load before the removal of DG and EE.
(3) Impact from Distributed Generation.
(4) Impact from Energy Efficiency.
(5) Impact from Electric Vehicles.
(6) Total System includes transmission wheeling Losses To Others.
(7) 10-Year Compounded Average Growth Rate.

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ENERGY (GWH)	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	20-YR (1) CAGR
Native System Forecast (NFL)											
Upper Bound	10,915	11,117	11,328	11,548	11,773	12,000	12,232	12,471	12,717	12,979	
Expected:	10,551	10,740	10,937	11,143	11,354	11,566	11,784	12,007	12,238	12,484	**1.8**
Lower Bound	10,187	10,362	10,547	10,738	10,935	11,133	11,335	11,543	11,758	11,989	
Less: DG	341	371	399	428	457	485	513	541	569	597	
Less: EE	444	484	524	565	605	646	686	726	767	807	
Plus: EE (5)	54	72	95	126	167	221	291	384	507	668	
Native System Energy:											
Upper Bound	10,119	10,262	10,421	10,596	10,786	10,993	11,223	11,482	11,780	12,135	
Expected:	**9,819**	**9,957**	**10,109**	**10,276**	**10,459**	**10,657**	**10,876**	**11,124**	**11,408**	**11,748**	**1.5**
Lower Bound	9,519	9,651	9,797	9,957	10,132	10,320	10,529	10,765	11,037	11,361	
Total System Net Energy:											
Upper Bound	10,077	10,220	10,379	10,553	10,744	10,951	11,180	11,440	11,738	12,093	
Expected:	**9,782**	**9,920**	**10,072**	**10,239**	**10,422**	**10,619**	**10,839**	**11,087**	**11,371**	**11,711**	**1.6**
Lower Bound	9,487	9,619	9,765	9,925	10,100	10,288	10,497	10,733	11,005	11,329	
DEMAND (MW)											
Native System Forecast											
Upper Bound	2,695	2,736	2,793	2,844	2,897	2,943	3,006	3,062	3,120	3,174	
Expected:	2,549	2,587	2,642	2,692	2,743	2,786	2,846	2,900	2,956	3,007	**1.6**
Lower Bound	2,402	2,439	2,492	2,539	2,588	2,629	2,687	2,739	2,792	2,841	
Less: DG	86	93	101	108	115	122	129	136	143	150	
Less: EE	85	92	100	108	115	123	131	138	146	154	
Plus: EV	26	35	46	61	81	107	142	187	247	325	
Native System Demand:											
Upper Bound	2,538	2,571	2,623	2,674	2,731	2,788	2,870	2,957	3,060	3,179	
Expected:	**2,404**	**2,436**	**2,488**	**2,538**	**2,593**	**2,648**	**2,728**	**2,813**	**2,913**	**3,028**	**1.7**
Lower Bound	2,270	2,302	2,352	2,401	2,455	2,509	2,587	2,669	2,766	2,877	
Total System Demand:											
Upper Bound	2,527	2,561	2,613	2,664	2,721	2,778	2,859	2,946	3,050	3,169	
Expected:	**2,395**	**2,427**	**2,479**	**2,529**	**2,584**	**2,639**	**2,719**	**2,804**	**2,904**	**3,019**	**1.7**
Lower Bound	2,263	2,294	2,345	2,394	2,448	2,501	2,579	2,661	2,758	2,869	
Interruptible Load:	56	56	56	56	56	56	56	56	56	56	
Upper Bound	2,464	2,497	2,549	2,600	2,657	2,714	2,795	2,882	2,986	3,105	
Expected:	**2,339**	**2,371**	**2,423**	**2,473**	**2,528**	**2,583**	**2,663**	**2,748**	**2,848**	**2,963**	**1.6**
Lower Bound	2,214	2,246	2,297	2,345	2,400	2,453	2,531	2,613	2,710	2,821	

Footnotes:
(1) 20-Year Compounded Average Growth Rate.

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	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Sales Forecasts											
TX Residential		2,548,620	2,630,735	2,705,391	2,769,328	2,836,687	2,911,624	2,997,171	3,086,017	3,176,626	3,273,664
TX Small C&I		1,863,659	1,901,286	1,923,505	1,942,160	1,961,062	1,982,670	2,005,127	2,027,718	2,052,316	2,078,571
TX Large C&I		910,471	915,710	920,271	924,242	927,699	930,710	933,331	935,613	937,599	939,329
TX Street Lighting		38,843	39,342	39,763	40,188	40,618	41,048	41,462	41,860	42,266	42,692
TX OPA		1,098,802	1,116,932	1,127,163	1,137,598	1,146,861	1,155,861	1,163,721	1,167,953	1,174,536	1,181,460
NM Residential		807,579	839,514	861,530	882,968	904,634	929,084	955,151	982,673	1,011,638	1,040,411
NM Small C&I		500,347	513,497	521,042	528,316	537,235	547,884	559,456	572,532	585,773	597,470
NM Large C&I		70,923	70,565	70,421	70,363	70,339	70,330	70,326	70,324	70,324	70,323
NM Street Lighting		1,853	1,890	1,919	1,949	1,980	2,011	2,043	2,075	2,107	2,140
NM OPA		357,745	363,637	364,391	365,714	366,169	367,098	368,571	370,483	372,936	376,307
EE Energy Forecast											
TX Residential		5,410	10,919	16,378	21,837	27,296	32,756	38,215	43,674	49,134	54,593
TX Small C&I		16,694	33,692	50,537	67,383	84,229	101,075	117,920	134,766	151,612	168,458
TX Large C&I		1,163	2,348	3,522	4,696	5,870	7,044	8,218	9,392	10,566	11,740
NM Residential		8,685	17,371	26,056	34,742	43,427	52,112	60,798	69,483	78,169	86,854
NM Small C&I		5,149	10,297	15,446	20,595	25,744	30,892	36,041	41,190	46,339	51,487
NM Large C&I		428	856	1,284	1,711	2,139	2,567	2,995	3,423	3,851	4,279
EE Demand Forecast											
TX Residential		2.06	4.11	6.17	8.22	10.28	12.33	14.39	16.44	18.50	20.55
TX Small C&I		3.01	6.01	9.02	12.03	15.04	18.04	21.05	24.06	27.07	30.07
TX Large C&I		0.27	0.53	0.80	1.07	1.33	1.60	1.87	2.13	2.40	2.66
NM Residential		1.38	2.76	4.14	5.52	6.90	8.28	9.67	11.05	12.43	13.81
NM Small C&I		0.38	0.77	1.15	1.54	1.92	2.31	2.69	3.08	3.46	3.85
NM Large C&I		0.05	0.11	0.16	0.22	0.27	0.33	0.38	0.44	0.49	0.55

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	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Sales Forecasts										
TX Residential	3,374,050	3,470,835	3,572,613	3,679,067	3,790,289	3,904,028	4,018,421	4,136,385	4,257,208	4,384,825
TX Small C&I	2,102,978	2,128,721	2,155,639	2,183,264	2,211,185	2,238,618	2,266,631	2,294,996	2,325,038	2,357,848
TX Large C&I	940,835	942,146	943,288	944,282	945,147	945,901	946,557	947,128	947,625	948,058
TX Street Lighting	43,155	43,620	44,068	44,499	44,918	45,333	45,733	46,118	46,490	46,852
TX OPA	1,186,863	1,192,405	1,198,251	1,203,752	1,208,464	1,212,809	1,218,131	1,223,484	1,229,512	1,237,871
NM Residential	1,067,928	1,096,654	1,126,003	1,157,160	1,189,258	1,221,538	1,254,519	1,288,940	1,324,372	1,362,948
NM Small C&I	611,943	626,086	641,013	656,164	670,577	685,816	702,502	719,968	737,745	754,841
NM Large C&I	70,323	70,323	70,323	70,323	70,323	70,323	70,323	70,323	70,323	70,323
NM Street Lighting	2,173	2,208	2,243	2,278	2,313	2,349	2,384	2,419	2,454	2,488
NM OPA	378,368	381,241	384,416	388,124	391,977	395,513	398,796	401,977	405,194	409,332
EE Energy Forecast										
TX Residential	60,052	65,512	70,971	76,430	81,889	87,349	92,808	98,267	103,727	109,186
TX Small C&I	185,303	202,149	218,995	235,841	252,686	269,532	286,378	303,224	320,069	336,915
TX Large C&I	12,913	14,087	15,261	16,435	17,609	18,783	19,957	21,131	22,305	23,479
NM Residential	95,539	104,225	112,910	121,596	130,281	138,966	147,652	156,337	165,023	173,708
NM Small C&I	56,636	61,785	66,934	72,082	77,231	82,380	87,529	92,677	97,826	102,975
NM Large C&I	4,706	5,134	5,562	5,990	6,418	6,846	7,274	7,701	8,129	8,557
EE Demand Forecast										
TX Residential	22.61	24.66	26.72	28.77	30.83	32.88	34.94	36.99	39.05	41.10
TX Small C&I	33.08	36.09	39.10	42.10	45.11	48.12	51.12	54.13	57.14	60.15
TX Large C&I	2.93	3.20	3.46	3.73	4.00	4.26	4.53	4.80	5.06	5.33
NM Residential	15.19	16.57	17.95	19.33	20.71	22.09	23.47	24.85	26.23	27.61
NM Small C&I	4.23	4.62	5.00	5.39	5.77	6.15	6.54	6.92	7.31	7.69
NM Large C&I	0.60	0.66	0.71	0.76	0.82	0.87	0.93	0.98	1.04	1.09

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EV Demand Forecast		0.39	0.91	1.59	2.49	3.67	5.23	7.28	9.97	13.52	18.19
EV Energy Forecast		0.8139	1.8852	3	5	8	11	15	21	28	38
Other Forecasts											
RGEC MWH		64,793	65,998	67,203	68,408	69,613	70,819	72,024	73,229	74,434	75,639
Company Use MWH		12,924	13,040	13,157	13,276	13,395	13,516	13,637	13,760	13,884	14,009
DG Energy (MWH)		34,401	68,631	97,052	125,406	153,539	181,528	209,373	237,151	264,709	292,122
DG Demand (MW)		8.62	17.20	24.33	31.42	38.47	45.49	52.47	59.42	66.32	73.20
Losses											
Losses to Others MWH	-167,409	-37,112	-37,112	-37,112	-37,112	-37,112	-37,112	-37,112	-37,112	-37,112	-37,112
Losses to Others MW	-26.00	-8.96	-8.96	-8.96	-8.96	-8.96	-8.96	-8.96	-8.96	-8.96	-8.96
System Loss Factor(Energy)		0.069	0.069	0.069	0.069	0.069	0.069	0.069	0.069	0.069	0.069
System Loss Factor(Demand)		0.0754	0.0754	0.0754	0.0754	0.0754	0.0754	0.0754	0.0754	0.0754	0.0754
Other Data											
System Load Factor		0.472579932	0.4725799	0.4725799	0.4725799	0.4725799	0.4725799	0.4725799	0.4725799	0.4725799	0.4725799
Interruptible Forecast		52	52	52	52	52	52	52	52	52	52
Hours in a Year	8,760	8,760	8,760	8,760	8,784	8,760	8,760	8,760	8,784	8,760	8,760
Native System Energy	8,674,263										
Previous Year's Peak	2,173										

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EV Demand Forecast	24.34	32.43	43.08	57.10	75.56	99.85	131.83	173.92	229.32	302.25
EV Energy Forecast	50	67	89	118	156	206	273	360	474	625
Other Forecasts										
RGEC MWH	76,844	78,050	79,255	80,460	81,665	82,870	84,076	85,281	86,486	87,691
Company Use MWH	14,135	14,262	14,390	14,520	14,651	14,783	14,916	15,050	15,185	15,322
DG Energy (MWH)	319,391	346,594	373,576	400,413	427,107	453,734	480,140	506,402	532,520	558,572
DG Demand (MW)	80.03	86.84	93.60	100.33	107.02	113.68	120.30	126.88	133.43	139.94
Losses										
Losses to Others MWH	-37,112	-37,112	-37,112	-37,112	-37,112	-37,112	-37,112	-37,112	-37,112	-37,112
Losses to Others MW	-8.96	-8.96	-8.96	-8.96	-8.96	-8.96	-8.96	-8.96	-8.96	-8.96
System Loss Factor(Energy)	0.069	0.069	0.069	0.069	0.069	0.069	0.069	0.069	0.069	0.069
System Loss Factor(Demand)	0.0754	0.0754	0.0754	0.0754	0.0754	0.0754	0.0754	0.0754	0.0754	0.0754
Other Data										
System Load Factor	0.4725799	0.4725799	0.4725799	0.4725799	0.4725799	0.4725799	0.4725799	0.4725799	0.4725799	0.4725799
Interruptible Forecast	52	52	52	52	52	52	52	52	52	52
Hours in a Year	8,760	8,784	8,760	8,760	8,760	8,784	8,760	8,760	8,760	8,784
Native System Energy										
Previous Year's Peak										

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Energy (MWH)	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Total Texas Forecasts	6,460,395	6,604,004	6,716,093	6,813,517	6,912,928	7,021,912	7,140,812	7,259,160	7,383,342	7,515,716
Total New Mexico Forecasts	1,738,447	1,789,103	1,819,303	1,849,310	1,880,357	1,916,408	1,955,547	1,998,087	2,042,779	2,086,651
RGEC Forecast	64,793	65,998	67,203	68,408	69,613	70,819	72,024	73,229	74,434	75,639
Company Use	12,924	13,040	13,157	13,276	13,395	13,516	13,637	13,760	13,884	14,009
Basic Native System Losses	571,082	584,578	594,487	603,371	612,464	622,563	633,559	644,752	656,496	668,749
Basic Native System NFL	8,847,640	9,056,723	9,210,243	9,347,881	9,488,757	9,645,217	9,815,580	9,988,988	10,170,935	10,360,764

Native System Load Factor	0.4726	0.4726	0.4726	0.4726	0.4726	0.4726	0.4726	0.4726	0.4726	0.4726

Demand (MW)										
Basic Native System	2,137	2,188	2,225	2,252	2,292	2,330	2,371	2,406	2,457	2,503

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Energy (MWH)	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Total Texas Forecasts	7,647,881	7,777,728	7,913,859	8,054,863	8,200,003	8,346,689	8,495,472	8,648,111	8,805,874	8,975,454
Total New Mexico Forecasts	2,130,735	2,176,511	2,223,998	2,274,048	2,324,449	2,375,539	2,428,523	2,483,627	2,540,088	2,599,932
RGEC Forecast	76,844	78,050	79,255	80,460	81,665	82,870	84,076	85,281	86,486	87,691
Company Use	14,135	14,262	14,390	14,520	14,651	14,783	14,916	15,050	15,185	15,322
Basic Native System Losses	681,002	693,212	705,974	719,249	732,833	746,572	760,586	775,013	789,887	805,810
Basic Native System NFL	10,550,598	10,739,763	10,937,475	11,143,140	11,353,600	11,566,453	11,783,573	12,007,082	12,237,520	12,484,209

Native System Load Factor	0.4726	0.4726	0.4726	0.4726	0.4726	0.4726	0.4726	0.4726	0.4726	0.4726

Demand (MW)										
Basic Native System	2,549	2,587	2,642	2,692	2,743	2,786	2,846	2,900	2,956	3,007

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PUC DOCKET NO. 52195

APPLICATION OF EL PASO	§	BEFORE THE STATE OFFICE
ELECTRIC COMPANY TO CHANGE	§	OF
RATES	§	ADMINISTRATIVE HEARINGS

EL PASO ELECTRIC COMPANY'S RESPONSE TO
FREEPORT-MCMORAN, INC'S FIRST REQUEST FOR INFORMATION
QUESTION NOS. FMI 1-1 THROUGH FMI 1-25

FMI 1-3:

The following Interrogatories pertains to the Direct Testimony of David C. Hawkins.

Provide the most current version of Exhibit DCH-3 along with supporting documents in "live" EXCEL format.

RESPONSE:

Please refer to FMI 1-3, Attachment 1 for a copy of Exhibit DCH-3 in Excel format. Exhibit DCH-3 is the most current version of the Loads and Resource report ("L&R"). Please reference FMI 1-2, Attachment 1, which was utilized for the load forecast in Exhibit DCH-3, and FMI 1-3, Attachments 2 and 3, which include information used in developing Exhibit DCH-3.

Preparer:	Omar Gallegos	Title:	Senior Director – Resource Planning & Management
Sponsor:	David C. Hawkins	Title:	Vice President – Strategy & Sustainability

El Paso Electric Company
Loads & Resources 2021-2030 w/ 2021 Updated Load Forecast
Issued 7/2/2020

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
		170 Solar 100/50 Sol/Batt	Newman 6		48 Geo 100/100 Sol/Batt		130 Solar CT 100 CT 228			48 Geo
1.0 GENERATION RESOURCES[1]										
1.1 RIO GRANDE	271	271	227	227	227	227	227	227	227	227
1.2 NEWMAN	729	729	809	809	809	809	496	496	496	496
1.3 COPPER	63	63	63	63	63	63	63	63	63	63
1.4 MONTANA	352	352	352	352	352	352	352	352	352	352
1.5 PALO VERDE	622	622	622	622	622	622	622	622	622	622
1.6 RENEWABLES[2]	6	6	6	5	5	5	5	5	5	5
1.7 STORAGE	0	0	0	0	0	0	0	0	0	0
1.8 POSSIBLE EMERGING TECHNOLOGY EXPANSION[3]	0	0	0	0	40	40	40	40	40	40
1.9 INTERRUPTIBLE[4]	56	56	56	56	56	56	56	56	56	56
1.10 LINE LOSSES FROM OTHERS[5]	8	8	8	8	8	8	8	8	8	8
1.0 TOTAL GENERATION RESOURCES	**2107**	**2107**	**2143**	**2142**	**2182**	**2182**	**1869**	**1869**	**1869**	**1869**
2.0 RESOURCE PURCHASES										
2.1 RENEWABLE PURCHASE[6]	73	72	72	72	71	71	70	70	69	69
2.2 NEW RENEWABLE PURCHASE[7]	0	43	42	42	42	42	41	41	41	41
2.3 NEW RENEWABLE/ BATTERY PURCHASE[8]	0	75	75	75	75	75	74	74	74	74
2.4 NEW BATTERY PURCHASE[9]	0	0	0	0	0	0	0	0	0	0
2.5 MARKET RESOURCE PURCHASE[10]	195	100	95	125	0	20	15	45	100	100
2.0 TOTAL RESOURCE PURCHASES	**268**	**290**	**284**	**314**	**188**	**208**	**200**	**230**	**284**	**284**
3.0 FUTURE RESOURCES[11]										
3.1 RENEWABLE	0	0	0	0	48	48	81	81	81	129
3.2 RENEWABLE/STORAGE	0	0	0	0	100	100	100	100	100	100
3.3 GAS GENERATION	0	0	0	0	0	0	328	328	328	328
3.0 TOTAL RESOURCE PURCHASES	**0**	**0**	**0**	**0**	**148**	**148**	**509**	**509**	**509**	**557**
4.0 TOTAL NET RESOURCES (1.0 + 2.0 + 3.0)	**2375**	**2397**	**2427**	**2456**	**2518**	**2538**	**2578**	**2608**	**2662**	**2710**
5.0 SYSTEM DEMAND[12]										
5.1 NATIVE SYSTEM DEMAND[13]	**2138**	**2189**	**2227**	**2255**	**2296**	**2335**	**2379**	**2417**	**2471**	**2522**
5.2 DISTRIBUTED GENERATION	(9)	(19)	(22)	(22)	(22)	(22)	(22)	(22)	(22)	(22)
5.3 ENERGY EFFICIENCY	(8)	(15)	(23)	(31)	(38)	(46)	(54)	(62)	(69)	(77)
6.0 TOTAL SYSTEM DEMAND (5.1 - (5.2+5.3))	**2121**	**2155**	**2182**	**2202**	**2236**	**2267**	**2303**	**2334**	**2380**	**2423**
7.0 MARGIN OVER TOTAL DEMAND (4.0 - 6.0)	**254**	**242**	**245**	**254**	**282**	**271**	**275**	**274**	**282**	**287**
8.0 PLANNING RESERVE 15% OF TOTAL DEMAND	**318**	**323**	**327**	**330**	**335**	**340**	**345**	**350**	**357**	**364**
9.0 MARGIN OVER RESERVE (7.0 - 8.0)	**(64)**	**(81)**	**(82)**	**(76)**	**(53)**	**(70)**	**(71)**	**(76)**	**(75)**	**(77)**

Planned Generation Additions
100 MW Solar (25 MW at Peak) in 2022
Solar/Batt Combo (100/50 MW) in 2022 (75 MW at Peak)
Newman 6 GT5 (228 MW) in 2023
70 MW Solar (18 MW at Peak) in 2022

Unit Retirements
Rio Grande 6 (45MW) (inactive reserve)
Rio Grande 7 (44MW) - December 2022
Newman 1 (74MW) - December 2022
Newman 2 (74MW) - December 2022
Newman 3 (93MW) - December 2026
Newman 4 CC (220MW) - December 2026
Copper (63MW) - December 2030
Rio Grande 8 (139MW) - December 2033

Company Owned Renewables
Line 1.6 consists of EPE Community Solar, Holloman Solar, EPCC, Stanton, Wrangler, Rio Grande & Newman Carports and Van Horn

Renewable Purchases
Line 2.1 includes SunEdison, NRG, Macho Springs, Juwi, and Hatch solar purchases (70% availability at Peak)

New Renewable Purchase
Line 2.2 includes system solar resource 100 MW Solar (25 at Peak) and NM RPS solar resource 70 MW in 2022 (18 MW at Peak)

Resource Purchase
This purchase is supported by firm transmission through (i) simultaneous buy/sell with
(i) Freeport McMoRan (formerly Phelps Dodge),
(ii) Four Corners-West Mesa transmission

Future Resources (subject to RFP results)
Line 3.0 includes
48 MW Geothermal NM RPS resource in 2025
100/100 MW Solar/Batt Combo NM RPS in 2025
130 MW Solar (33 MW at Peak) system resource in 2027
100 MW CT system resource in 2027
228 MW CT System Resource in 2027

1. Generation unit retirements are consistent with the 2018 IRP. Rio Grande 6 is classified as inactive reserve.
2. Existing EPE owned solar renewables at 70 percent contribution to peak.
3. Emerging technologies may include customer or other distributed resources as well as additional community solar.
4. Interruptible customer capacity shifted to the resource side of the L&R. Capacity MW contribution per 2020 Load Forecast.
5. Line losses from others shifted to resource side of the L&R and is the typical amount of repayment of transmission wheeling losses from transimission customers with in-kind energy during peak hours.
6. Existing renewable solar PPAs at 70 percent contribution to peak.
7. New renewable solar PPAs at 25 percent contribution to peak.
8. New solar and battery storage PPAs with solar at 25 percent contribution to peak.
9. 50 MW stand-alone battery was denied in NMPRC Case No. 19-00348-UT. The resource purchase on line 2.5 was adjusted to replace 50 MW capacity as required to meet the planning reserve margin.
10. Denotes market purchase either spot market or short-term purchased power. Amounts greater than 645 MW-PV output will need to come into EPE via exchange (Freeport), through the acquisition of additional transmission or on a non-firm path. Also, availability of such power is not guaranteed.
11. Future Resources from 2025 forward are to address both NM RPS and capacity needs. EPE will be initiating its 2021 IRP planning cycle which may result in changes to future planned resources.
12. System demand is based on the 2020 Long-Term Forecast dated April 1, 2021.
13. Native System Demand includes added load due to Electric Vehicles.

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El Paso Electric

EL PASO ELECTRIC COMPANY
REMOTE PLANT UNIT CAPACITY PROJECTIONS

UNIT	MDC - Peak Period Capacity (1) Total Unit	MDC - Peak Period Capacity (1) EPE % Share	MDC - Peak Period Capacity (1) EPE Net MW	DER - Average Annual Capacity (1) Total Unit	DER - Average Annual Capacity (1) EPE % Share	DER - Average Annual Capacity (1) EPE Net MW
Palo Verde Unit 1	1,311	15.8%	207	1,336	15.8%	211
Palo Verde Unit 2	1,314	15.8%	208	1,336	15.8%	211
Palo Verde Unit 3	1,312	15.8%	207	1,334	15.8%	211
Palo Verde Total	3,937	15.8%	622	4,006	15.8%	633

Effective Date: January 1, 2021

NOTES:
(1) Source: PVNGS Monthly Operating Worksheet(s). These values are not subject to change.

MDC: Maximum Dependable Capacity. The net electrical rating during the most restrictive seasonal conditions. (summer conditions)
DER: Design Electrical Rating. The nominal net electrical output used for purposes of plant design. (average yearly conditions)

A) Peak Period includes May thru September.
Ambient conditions impact unit output.
Table data for peak period is based on
95-102 °F and relative humidity of 10-20%.
B) SS: Station Service has already been netted out of MDC and DER.

Reviewed: ______________________
Nadia Powell Date

Reviewed: ______________________
David Hawkins Date

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EL PASO ELECTRIC COMPANY
LOCAL PLANT UNIT CAPACITY PROJECTIONS

	Peak Period Capacity [1]				Off-Peak Period Capacity			Unit Minimum Capacity			
UNIT	MANUAL CTRL	Gross MW	SS[2]	Net MW	Gross MW	SS[2]	Net MW	MANUAL CTRL	Gross MW	SS[2]	Net MW
COP	64	64	1	63	66	1	65	4	4	1	3
NWM 1	80	78	4	74	82	4	78	30	33	4	29
NWM 2	80	78	4	74	82	4	78	30	33	4	29
NWM 3	100	98	5	93	103	5	98	30	33	5	28
NWM 4GT1	68	68	1	67	72	1	71	10	35	1	34
NWM 4GT2	68	68	1	67	72	1	71	10	35	1	34
NWM 4GT, NWM 4ST[3]	112	112	2	110	118	2	116	85	85	2	83
NWM4 GT1 & GT2, NWM4 ST & DF[3]	224	224	4	220	236	4	232	98	98	4	94
NWM 5GT3	72	72	2	70	73	2	71	36	36	2	34
NWM 5GT4	72	72	2	70	73	2	71	36	36	2	34
NWM 5GT & NWM 5ST & DF	138	138	4	134	139	4	135	108	108	3	105
NWM5 GT3 & GT4, NWM5 ST & DF	276	276	8	268	279	8	271	128	128	7	121
RGD 6	47	47	2	45	49	2	47	18	20	2	18
RGD 7	47	46	2	44	50	2	48	18	20	2	18
RGD 8	150	145	6	139	153	6	147	46	50	6	44
RGD 9	90	90	2	88	92	2	90	20	20	2	18
MPS 1	90	90	2	88	95	2	93	20	20	2	18
MPS 2	90	90	2	88	95	2	93	20	20	2	18
MPS 3	90	90	2	88	95	2	93	20	20	2	18
MPS 4	90	90	2	88	95	2	93	20	20	2	18

Effective Date: January 1, 2020

NOTES:
1. Peak Period includes May thru September.
   Ambient conditions impact unit output.
   Table data for peak period is based on
   95-102 °F and relative humidity of 10-20%.
2. SS: Station Service values are average values for
   normal equipment in service.
3. U4 EVAP COOLERS OOS OCT-APR. Includes 20 MW for duct burners
4. Min capacities are based on boiler/turbine controls in auto mode.

Duct Firing (DF): Included in table
- Duct firing NM4 total output: 10MW per CT online added to Steamer output
- Duct Firing NM5 total output: 10MW per CT online added to Steamer output

Reviewed: ______________________ ________
Fred Prutch Date

Reviewed: ______________________ ________
John D. Aranda Date

Reviewed: ______________________ ________
Albert Montano Date

Reviewed: ______________________ ________
Louie Guaderrama Date

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APPLICATION OF EL PASO ELECTRIC COMPANY TO CHANGE RATES	§ § §	BEFORE THE STATE OFFICE OF ADMINISTRATIVE HEARINGS

EL PASO ELECTRIC COMPANY'S RESPONSE TO FREEPORT-MCMORAN, INC'S FIRST REQUEST FOR INFORMATION QUESTION NOS. FMI 1-1 THROUGH FMI 1-25

FMI 1-4:

The following Interrogatories pertains to the Direct Testimony of David C. Hawkins.

Referring to page 8, lines 11-32:

a. Is the capacity provided by the New Mexico PPAs included as firm capacity in EPE's L&R Table? If not, please explain your response.

b. Are the solar projects that provide electricity under the New Mexico PPAs essentially identical to the Macho Springs and Newman solar projects? If not, state all differences.

RESPONSE:

a. Yes, the capacity contribution to peak load from each of the New Mexico PPAs is included in the loads and resources table as firm capacity. The existing New Mexico PPAs are included in row 2.1 of Exhibit DCH-3 along with the Macho Springs and Newman solar projects.

b. They are "essentially" similar to the Macho Springs and Newman solar projects in that they are stand-alone solar facilities (i.e. no battery storage) with some form of solar tracking. Some of the unique differences, but not an all-inclusive list of all detailed differences, are name plate capacity, geographic location, photovoltaic panels and tracking systems.

Preparer:	Omar Gallegos	Title:	Senior Director – Resource Planning Management
Sponsor:	David C. Hawkins	Title:	Vice President – Strategy and Sustainability

SOAH DOCKET NO. 473-21-2606
PUC DOCKET NO. 52195

APPLICATION OF EL PASO ELECTRIC COMPANY TO CHANGE RATES	§ § §	BEFORE THE STATE OFFICE OF ADMINISTRATIVE HEARINGS

EL PASO ELECTRIC COMPANY'S RESPONSE TO FREEPORT-MCMORAN, INC'S FIRST REQUEST FOR INFORMATION QUESTION NOS. FMI 1-1 THROUGH FMI 1-25

FMI 1-5:

The following Interrogatories pertains to the Direct Testimony of David C. Hawkins.

Referring to page 9, lines 7-13:

a. Explain how the imputed capacity charges were derived and provide supporting workpapers in “live” EXCEL format.

b. Explain why the imputed capacity charges do not reflect the incremental capacity cost as stated in Mr. Carasco’s [*sic*] testimony (on page 27, line 6).

RESPONSE:

a. These charges, as approved in Docket No. 46831 (Finding of Fact No. 33) effective August 1, 2017, are based on the WSPP (formerly known as Western Systems Power Pool) Agreement capacity rate of $7.32/kW/Month, with adjustments made based on the intermittency of these two resources. EPE adjusted the imputed capacity charges to reflect the additional ancillary services attributable to an intermittent resource. This adjustment is based on the FERC accepted ancillary service rates within EPE's OATT. Additionally, EPE made adjustments to reflect the Test Year (per Docket No. 46831) energy output associated with the Solar PPAs. The imputed capacity charge was $7.20/kW/Month after adjusting for the associated ancillary service schedules found in EPE's OATT. The applicable schedules are Schedule 3 (Regulation and Frequency Response), Schedule 5 (Operating Reserve Spinning Reserve Service), and Schedule 6 (Operating Reserve Supplemental Reserve Service). The rate for each of these schedules is $3.10/kW/Month. Schedule 3 requires 0.87 percent of rated MW obligation, and Schedules 5 and 6 each requires 1.5 percent of rated MW obligation. Adjusting the WSPP rate of $7.32/kW/Month, by the combined Schedules 3, 5, and 6 obligations of 3.87 percent (i.e., 0.87% + 1.50% + 1.50%), multiplied by the rate of $3.10/kW/month, the "net capacity rate" is $7.20/kW/Month (i.e., $7.32/kW/Month – (.0387 X

3.10/kW/Month)). EPE based the energy production output component of the imputed capacity charge on actual Test Year production. Macho Springs had a 32.6 percent energy production output level, and Newman Solar had a 32.3 percent energy production output. The final imputed capacity charges are the products of the "net capacity rate" and the Test Year energy output percentages. The resulting imputed capacity charges are $2.35/kW/Month for the Macho Springs PPA, and $2.33/kW/Month for the Newman Solar PPA.

See FMI 1-5 Attachments 1 and 2.

b. The imputed capacity costs for the solar PPAs were calculated per the response in FMI 1-5 (a) above and reflect the imputed capacity value in an energy only purchased power agreement of an intermittent resource with a low capacity factor. This is not related to the incremental capacity cost referenced by Mr. Carrasco on page 27 of his direct testimony.

Preparer: Omar Gallegos — Title: Senior Director – Resource Planning Management

Sponsor: David C. Hawkins — Title: Vice President – Strategy and Sustainability

Manuel Carrasco — Manager – Rate Research

DCH-WP2

El Paso Electric Company
Macho Springs Solar Facility - PPA
Summary of Imputed Capacity Charge

Imputed Capacity Calculation

EPE's Macho Springs Solar annual expected **capacity factor** is			**32.6%**	
WSPP max contract demand charge rate (Section A-3.7, B-3.6, C-3.6)			**$7.320**	/KW-Month
GE report - intermittent resource require ancillary services and should be deducted from imputed capacity				
EPE's OATT				
Sched 3 (Regulation)	$3.10	0.87%		of rated capacity
Sched 5 (Operating Reserves)		1.50%		
Sched 6 (Supple Reserves)		1.50%		
EPE Ancillary Services	$3.10	3.87%	**$0.120**	/KW-Month
WSPP MINUS EPE ANCILLARY --- NET			**$7.200**	/KW-Month at 100% CF
			32.6%	Est Annual CF for Solar
			2.350	/KW-Month
	Total Company		100%	
	Mach Springs, KW		50,000	
	Estimate Macho Springs Demand Charge, $/Month		**$117,500**	
	Annual charge		**$1,410,000**	

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Source:

WSPP AGREEMENT

WSPP INC.
FIRST REVISED RATE SCHEDULE FERC NO. 6
Superseding
Rate Schedule FERC No. 6

in Section 201(e) of the Federal Power Act, 16 U.S.C. § 824(e).

A-3.7 Except as provided for in Section A-3.6, the price shall not exceed the Seller's forecasted Incremental Cost plus up to: $7.32/kW/ month; $1.68/kW/week; 33.78¢/kW/day; 14.07 mills/kWh; or 21.11 mills/kWh for service of sixteen (16) hours or less per day. The hourly rate is capped at the Seller's forecasted Incremental Cost plus 33.78¢/kW/ day. The total demand charge revenues in any consecutive seven-day period shall not exceed the product of the weekly rate and the highest demand experienced on any day in the seven-day period. In lieu of payment, such Parties may mutually agree to exchange economy energy at a ratio not to exceed that ratio provided for in Section C-3.6 of Service Schedule C. The Seller's forecasted Incremental Cost discussed above also may include any transmission and/or ancillary service costs associated with the sale, including the cost of any

WSPP AGREEMENT SCHEDULE Q FOR SOUTHWESTERN PUBLIC SERVICE COMPANY

Determination of Ceiling Rates Applicable to Sales Made by Southwestern Public Service Company under the WSPP Agreement

1. The following rates shall be applicable to any cost-based sale of power and/or energy made by Southwestern Public Service Company ("SPS") (1) pursuant to the WSPP Agreement, including under Service Schedule A (Economy Energy Service), Service Schedule B (Unit Commitment Service), and Service Schedule C (Firm Capacity/Energy Sale or Exchange Service and (2) at a delivery point located within the SPS balancing authority area.

2. The rates for any cost-based power and/or energy sale made pursuant to the WSPP Agreement from SPS generation resources shall not exceed the following:

<u>Maximum Demand Charge:</u>

Monthly	\$ 7.56/kW
Weekly	\$ 1.745/kW
Daily (On-peak)	\$ 0.349/kW, provided, however, that the Total Weekly charges for a customer paying the Daily rate of \$0.349/kW (on-peak) or \$0.249 (off-peak) shall not exceed the product of the number of kilowatts sold for a week multiplied by the maximum Weekly demand charge of \$1.745/kW.
Daily (Off-peak)	\$ 0.249/kW
Hourly	\$ 21.813/MW, provided, however, that the Total Daily charges for a customer paying the Hourly rate of \$21.813/MW shall not exceed the product of the number of kilowatts sold for a day multiplied by the maximum Daily (on-peak) demand charge, and total Weekly charges for such a customer shall not exceed the product of the number of kilowatts sold for a week multiplied by the maximum Weekly demand charge of \$1.745/kW.

B-3.6 Except as provided for in Section B-3.5, the price shall not exceed the Seller's forecasted Incremental Cost plus up to: $7.32/kW/month; $1.68/kW/week; 33.78¢/kW/day; 14.07 mills/kWh; or 21.11 mills/kWh for service of sixteen (16) hours or less per day. The hourly rate is capped at the Seller's forecasted Incremental Cost plus 33.78¢/kW/day. The total demand charge revenues in any consecutive seven-day period shall not exceed the product of the weekly rate and the highest demand experienced on any day in the seven-day period. The Seller's forecasted Incremental Cost discussed above also may include any transmission and/or ancillary service costs associated with the sale, including the cost of any transmission and/or ancillary services that the Seller must take on its own system. Any such transmission and/or ancillary service charges shall be separately identified by the Seller to the Purchaser. The transmission and ancillary service rate ceilings shall be available through the WSPP's Hub or homepage. The foregoing hourly rate

C-3.6 Except as provided for in Section C-3.5, the price shall not exceed the Seller's forecasted Incremental Cost plus up to: $7.32/kW/month; $1.68/kW/week; 33.78¢/kW/day; 14.07 mills/kWh; or 21.11 mills/kWh for service of sixteen (16) hours or less per day. The hourly rate is capped at the Seller's forecasted Incremental Cost plus 33.78¢/kW/day. The total demand charge revenues in any consecutive seven-day period shall not exceed the product of the weekly rate and the highest demand experienced on any day in the seven-day period. Exchange ratios among such Parties shall be as mutually agreed between the Purchaser and the Seller, but shall not exceed the ratio of 1.5 to 1.0. The Seller's forecasted Incremental Cost discussed above also may include any transmission and/or

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Open Access Transmission Tariff

El Paso Electric Company

Open Access Transmission Tariff

Document Generated On: 1/26/2016

SCHEDULE 3

Regulation and Frequency Response Service

Regulation and Frequency Response Service is necessary to provide for the continuous balancing of resources (generation and interchange) with load and for maintaining scheduled Interconnection frequency at sixty cycles per second (60 Hz). Regulation and Frequency Response Service is accomplished by committing on-line generation whose output is raised or lowered (predominantly through the use of

automatic generating control equipment) and by other non-generation resources capable of providing this service as necessary to follow the moment-by-moment changes in load. The obligation to maintain this balance between resources and load lies with the Transmission Provider (or the Control Area operator that performs this function for the Transmission Provider). The Transmission Provider must offer this service when the transmission service is used to serve load within its Control Area. The Transmission Customer must either purchase this service from the Transmission Provider or make alternative comparable arrangements to satisfy its Regulation and Frequency Response Service obligation. The Transmission Provider will take into account the speed and accuracy of regulation resources in its determination of Regulation and Frequency Response reserve requirements, including as it reviews whether a self-supplying Transmission Customer has made alternative comparable arrangements. Upon request by the self-supplying Transmission Customer, the Transmission Provider will share with the Transmission Customer its reasoning and any related data used to make the determination of whether the Transmission Customer has made alternative comparable arrangements. The amount of and charges for Regulation and Frequency Response Service are set forth below. To the extent the Control Area operator performs this service for the Transmission Provider, charges to the Transmission Customer are to reflect only a pass-through of the costs charged to the Transmission Provider by that Control Area operator.

Rate per $/KW-Year:$37.20
Rate per $/KW-Month:$3.10

Rate per $/KW-Week:$0.72
Rate per $/KW-Day:$0.102
Rate per $/KW-Hour:$0.0042

A Transmission Customer purchasing Regulation and Frequency Response Service will be required to purchase an amount of reserved capacity equal to 0.87 percent of the Transmission Customer's reserved capacity for point-to-point transmission service or 0.87 percent of the Transmission Customer's network load responsibility for Network Integration Transmission Service. The billing determinants for this service shall be reduced by any portion of the 0.87 percent purchase obligation that a Transmission Customer obtains from third parties or supplies itself.

SCHEDULE 5

Operating Reserve - Spinning Reserve Service

Spinning Reserve Service is needed to serve load immediately in the event of a system contingency. Spinning Reserve Service may be provided by generating units that are on-line and loaded at less than maximum output and by non-generation resources capable of providing this service. The Transmission Provider must offer this service when the transmission service is used to serve load within its Control Area. The Transmission Customer must either purchase this service from the Transmission Provider or make alternative comparable arrangements to satisfy its Spinning Reserve Service obligation. The amount of and charges for Spinning Reserve Service are set forth below.

To the extent the Control Area operator performs this service for the Transmission Provider, charges to the Transmission Customer are to reflect only a pass-through of the costs charged to the Transmission Provider by that Control Area operator.

Rate per $/KW-Year:$37.20
Rate per $/KW-Month:$3.10
Rate per $/KW-Week:$0.72
Rate per $/KW-Day:$0.102
Rate per $/KW-Hour:$0.0042

A Transmission Customer purchasing Operating Reserve - Spinning Reserve Service will be required to purchase an amount of reserved capacity equal to 1.5 percent of the Transmission Customer's reserved capacity for point-to-point transmission service used to serve load in the Transmission Provider's Control Area or, for Transmission Customers whose load within the Transmission Provider's Control Area is identified as Network Load, 1.5 percent of the Transmission Customer's network load responsibility for Network Integration Transmission Service. Transmission Customers with generating resources located within the Transmission Provider's Control Area, or generation which the Transmission Provider has agreed to provide Contingency Reserve responsibility through dynamic signal, will also be required to purchase an amount equal to 1.5 percent of the capacity of the specified generating resource identified as the source in the Transmission Customer's transmission schedule, unless another Control Area operator has agreed to carry the Contingency Reserve responsibility, through dynamic signal, for the generation resource. The billing determinants for this service shall be reduced by any

supplies itself.

SCHEDULE 6

Operating Reserve - Supplemental Reserve Service

Supplemental Reserve Service is needed to serve load in the event of a system contingency; however, it is not available immediately to serve load but rather within a short period of time. Supplemental Reserve Service may be provided by generating units that are on-line but unloaded, by quick-start generation or by interruptible load or other non-generation resources capable of providing this service. The Transmission Provider must offer this service when the transmission service is used to serve load within its Control Area. The Transmission Customer must either purchase this service from the Transmission Provider or make alternative comparable arrangements to satisfy its Supplemental Reserve Service obligation. The amount of and charges for Supplemental Reserve Service are set forth below. To the extent the Control Area operator performs this service for the Transmission Provider, charges to the Transmission Customer are to reflect only a pass-through of the costs charged to the Transmission Provider by that Control Area operator.

Rate per $/KW-Year:$37.20
Rate per $/KW-Month:$3.10
Rate per $/KW-Week:$0.72
Rate per $/KW-Day:$0.102

Rate per $/KW-Hour:$0.0042

A Transmission Customer purchasing Supplemental Reserve Service will be required to purchase an amount of reserved capacity equal to 1.5 percent of the Transmission Customer's reserved capacity for point-to-point transmission service used to serve load in the Transmission Provider's Control Area or, for Transmission Customers whose load within the Transmission Provider's Control Area is identified as Network Load, 1.5 percent of the Transmission Customer's network load responsibility for Network Integration Transmission Service. Transmission Customers with generating resources located within the Transmission Provider's Control Area, or generation which the Transmission Provider has agreed to provide Contingency Reserve responsibility through dynamic signal, will also be required to purchase an amount equal to 1.5 percent of the capacity of the specified generating resource identified as the source in the

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Execution Copy

Purchase Power Agreement

Between

Macho Springs Solar, LLC

and

El Paso Electric Company

October 25, 2012

EXHIBIT F

SELLER'S EXPECTED AND COMMITTED SOLAR ENERGY AND SOLAR ENERGY PAYMENT RATE

Commercial Operation Year	Expected Solar Energy (in MWh)	Committed Solar Energy (in MWh)	Solar Energy Payment Rate (in $/MWh)
1	149,440	112,080	$57.90
2	148,693	111,520	$57.90
3	147,949	110,962	$57.90
4	147,210	110,407	$57.90
5	146,474	109,855	$57.90
6	145,741	109,306	$57.90
7	145,012	108,759	$57.90
8	144,287	108,216	$57.90
9	143,566	107,674	$57.90
10	142,848	107,136	$57.90
11	142,134	106,600	$57.90
12	141,423	106,067	$57.90
13	140,716	105,537	$57.90
14	140,013	105,009	$57.90
15	139,312	104,484	$57.90
16	138,616	103,962	$57.90
17	137,923	103,442	$57.90
18	137,233	102,925	$57.90
19	136,547	102,410	$57.90
20	135,864	101,898	$57.90

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El Paso Electric Company
Newman Solar Facility - PPA
Summary of Imputed Capacity Charge

Imputed Capacity Calculation

EPE's Newman Solar annual expected **capacity factor** is				**32.3%**	NEWMAN Solar	
WSPP max contract demand charge rate (Section A-3.7, B-3.6, C-3.6)				**$7.320**	/KW-Month	
GE report - intermittent resource require ancillary services and should be deducted from imputed capacity						
EPE's OATT						
	Sched 3 (Regulation)	$3.10	0.87%	of rated capacity		
	Sched 5 (Operating Reserves)		1.50%			
	Sched 6 (Supple Reserves)		1.50%			
	EPE Ancillary Services	$3.10	3.87%	**$0.120**	/KW-Month	
WSPP MINUS EPE ANCILLARY --- NET				**$7.200**	/KW-Month	at 100% CF
				32.3%	Est Annual CF for Solar	
				2.330	/KW-Month	
		Total Company		100%		
		Newman Solar, KW		10,000		
		Estimate Newman Solar Demand Charge, $/Month		**$23,300**		
		Annual charge		**$279,600**		

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Source:

WSPP AGREEMENT

WSPP INC.
FIRST REVISED RATE SCHEDULE FERC NO. 6
Superseding
Rate Schedule FERC No. 6

in Section 201(e) of the Federal Power Act, 16 U.S.C. § 824(e).

A-3.7 Except as provided for in Section A-3.6, the price shall not exceed the Seller's forecasted Incremental Cost plus up to: $7.32/kW/ month; $1.68/kW/week; 33.78¢/kW/day; 14.07 mills/kWh; or 21.11 mills/kWh for service of sixteen (16) hours or less per day. The hourly rate is capped at the Seller's forecasted Incremental Cost plus 33.78¢/kW/ day. The total demand charge revenues in any consecutive seven-day period shall not exceed the product of the weekly rate and the highest demand experienced on any day in the seven-day period. In lieu of payment, such Parties may mutually agree to exchange economy energy at a ratio not to exceed that ratio provided for in Section C-3.6 of Service Schedule C. The Seller's forecasted Incremental Cost discussed above also may include any transmission and/or ancillary service costs associated with the sale, including the cost of any

WSPP AGREEMENT SCHEDULE Q FOR SOUTHWESTERN PUBLIC SERVICE COMPANY

Determination of Ceiling Rates Applicable to Sales Made by Southwestern Public Service Company under the WSPP Agreement

1. The following rates shall be applicable to any cost-based sale of power and/or energy made by Southwestern Public Service Company ("SPS") (1) pursuant to the WSPP Agreement, including under Service Schedule A (Economy Energy Service), Service Schedule B (Unit Commitment Service), and Service Schedule C (Firm Capacity/Energy Sale or Exchange Service and (2) at a delivery point located within the SPS balancing authority area.

2. The rates for any cost-based power and/or energy sale made pursuant to the WSPP Agreement from SPS generation resources shall not exceed the following:

   Maximum Demand Charge:

Monthly	$ 7.56/kW
Weekly	$ 1.745/kW
Daily (On-peak)	$ 0.349/kW, provided, however, that the Total Weekly charges for a customer paying the Daily rate of $0.349/kW (on-peak) or $0.249 (off-peak) shall not exceed the product of the number of kilowatts sold for a week multiplied by the maximum Weekly demand charge of $1.745/kW.
Daily (Off-peak)	$ 0.249/kW
Hourly	$ 21.813/MW, provided, however, that the Total Daily charges for a customer paying the Hourly rate of $21.813/MW shall not exceed the product of the number of kilowatts sold for a day multiplied by the maximum Daily (on-peak) demand charge, and total Weekly charges for such a customer shall not exceed the product of the number of kilowatts sold for a week multiplied by the maximum Weekly demand charge of $1.745/kW.

B-3.6 Except as provided for in Section B-3.5, the price shall not exceed the Seller's forecasted Incremental Cost plus up to: $7.32/kW/month; $1.68/kW/week; 33.78¢/kW/day; 14.07 mills/kWh; or 21.11 mills/kWh for service of sixteen (16) hours or less per day. The hourly rate is capped at the Seller's forecasted Incremental Cost plus 33.78¢/kW/day. The total demand charge revenues in any consecutive seven-day period shall not exceed the product of the weekly rate and the highest demand experienced on any day in the seven-day period. The Seller's forecasted Incremental Cost discussed above also may include any transmission and/or ancillary service costs associated with the sale, including the cost of any transmission and/or ancillary services that the Seller must take on its own system. Any such transmission and/or ancillary service charges shall be separately identified by the Seller to the Purchaser. The transmission and ancillary service rate ceilings shall be available through the WSPP's Hub or homepage. The foregoing hourly rate cap(s) are subject to the submission of cost justification by the applicable Seller to

C-3.6 Except as provided for in Section C-3.5, the price shall not exceed the Seller's forecasted Incremental Cost plus up to: $7.32/kW/month; $1.68/kW/week; 33.78¢/kW/day; 14.07 mills/kWh; or 21.11 mills/kWh for service of sixteen (16) hours or less per day. The hourly rate is capped at the Seller's forecasted Incremental Cost plus 33.78¢/kW/day. The total demand charge revenues in any consecutive seven-day period shall not exceed the product of the weekly rate and the highest demand experienced on any day in the seven-day period. Exchange ratios among such Parties shall be as mutually agreed between the Purchaser and the Seller, but shall not exceed the ratio of 1.5 to 1.0. The Seller's forecasted Incremental Cost discussed above also may include any transmission and/or

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Open Access Transmission Tariff

El Paso Electric Company

Open Access Transmission Tariff

Document Generated On: 1/26/2016

SCHEDULE 3

Regulation and Frequency Response Service

Regulation and Frequency Response Service is necessary to provide for the continuous balancing of resources (generation and interchange) with load and for maintaining scheduled Interconnection frequency at sixty cycles per second (60 Hz). Regulation and Frequency Response Service is accomplished by committing on-line generation whose output is raised or lowered (predominantly through the use of

automatic generating control equipment) and by other non-generation resources capable of providing this service as necessary to follow the moment-by-moment changes in load. The obligation to maintain this balance between resources and load lies with the Transmission Provider (or the Control Area operator that performs this function for the Transmission Provider). The Transmission Provider must offer this service when the transmission service is used to serve load within its Control Area. The Transmission Customer must either purchase this service from the Transmission Provider or make alternative comparable arrangements to satisfy its Regulation and Frequency Response Service obligation. The Transmission Provider will take into account the speed and accuracy of regulation resources in its determination of Regulation and Frequency Response reserve requirements, including as it reviews whether a self-supplying Transmission Customer has made alternative comparable arrangements. Upon request by the self-supplying Transmission Customer, the Transmission Provider will share with the Transmission Customer its reasoning and any related data used to make the determination of whether the Transmission Customer has made alternative comparable arrangements. The amount of and charges for Regulation and Frequency Response Service are set forth below. To the extent the Control Area operator performs this service for the Transmission Provider, charges to the Transmission Customer are to reflect only a pass-through of the costs charged to the Transmission Provider by that Control Area operator.

Rate per $/KW-Year:$37.20
Rate per $/KW-Month:$3.10

Rate per $/KW-Week:$0.72
Rate per $/KW-Day:$0.102
Rate per $/KW-Hour:$0.0042

A Transmission Customer purchasing Regulation and Frequency Response Service will be required to purchase an amount of reserved capacity equal to 0.87 percent of the Transmission Customer's reserved capacity for point-to-point transmission service or 0.87 percent of the Transmission Customer's network load responsibility for Network Integration Transmission Service. The billing determinants for this service shall be reduced by any portion of the 0.87 percent purchase obligation that a Transmission Customer obtains from third parties or supplies itself.

SCHEDULE 5

Operating Reserve - Spinning Reserve Service

Spinning Reserve Service is needed to serve load immediately in the event of a system contingency. Spinning Reserve Service may be provided by generating units that are on-line and loaded at less than maximum output and by non-generation resources capable of providing this service. The Transmission Provider must offer this service when the transmission service is used to serve load within its Control Area. The Transmission Customer must either purchase this service from the Transmission Provider or make alternative comparable arrangements to satisfy its Spinning Reserve Service obligation. The amount of and charges for Spinning Reserve Service are set forth below.

To the extent the Control Area operator performs this service for the Transmission Provider, charges to the Transmission Customer are to reflect only a pass-through of the costs charged to the Transmission Provider by that Control Area operator.

Rate per $/KW-Year:$37.20
Rate per $/KW-Month:$3.10
Rate per $/KW-Week:$0.72
Rate per $/KW-Day:$0.102
Rate per $/KW-Hour:$0.0042

A Transmission Customer purchasing Operating Reserve - Spinning Reserve Service will be required to purchase an amount of reserved capacity equal to 1.5 percent of the Transmission Customer's reserved capacity for point-to-point transmission service used to serve load in the Transmission Provider's Control Area or, for Transmission Customers whose load within the Transmission Provider's Control Area is identified as Network Load, 1.5 percent of the Transmission Customer's network load responsibility for Network Integration Transmission Service. Transmission Customers with generating resources located within the Transmission Provider's Control Area, or generation which the Transmission Provider has agreed to provide Contingency Reserve responsibility through dynamic signal, will also be required to purchase an amount equal to 1.5 percent of the capacity of the specified generating resource identified as the source in the Transmission Customer's transmission schedule, unless another Control Area operator has agreed to carry the Contingency Reserve responsibility, through dynamic signal, for the generation resource. The billing determinants for this service shall be reduced by any

supplies itself.

SCHEDULE 6

Operating Reserve - Supplemental Reserve Service

Supplemental Reserve Service is needed to serve load in the event of a system contingency; however, it is not available immediately to serve load but rather within a short period of time. Supplemental Reserve Service may be provided by generating units that are on-line but unloaded, by quick-start generation or by interruptible load or other non-generation resources capable of providing this service. The Transmission Provider must offer this service when the transmission service is used to serve load within its Control Area. The Transmission Customer must either purchase this service from the Transmission Provider or make alternative comparable arrangements to satisfy its Supplemental Reserve Service obligation. The amount of and charges for Supplemental Reserve Service are set forth below. To the extent the Control Area operator performs this service for the Transmission Provider, charges to the Transmission Customer are to reflect only a pass-through of the costs charged to the Transmission Provider by that Control Area operator.

Rate per $/KW-Year:$37.20
Rate per $/KW-Month:$3.10
Rate per $/KW-Week:$0.72
Rate per $/KW-Day:$0.102

Rate per $/KW-Hour:$0.0042

A Transmission Customer purchasing Supplemental Reserve Service will be required to purchase an amount of reserved capacity equal to 1.5 percent of the Transmission Customer's reserved capacity for point-to-point transmission service used to serve load in the Transmission Provider's Control Area or, for Transmission Customers whose load within the Transmission Provider's Control Area is identified as Network Load, 1.5 percent of the Transmission Customer's network load responsibility for Network Integration Transmission Service. Transmission Customers with generating resources located within the Transmission Provider's Control Area, or generation which the Transmission Provider has agreed to provide Contingency Reserve responsibility through dynamic signal, will also be required to purchase an amount equal to 1.5 percent of the capacity of the specified generating resource identified as the source in the

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Purchase Power Agreement

Between

Newman Solar LLC and

El Paso Electric Company

September 5, 2013

EXHIBIT F

SELLER'S EXPECTED AND COMMITTED SOLAR ENERGY AND SOLAR ENERGY PAYMENT RATE

Commercial Operation Year	Expected Solar Energy (in MWh)	Committed Solar Energy (in MWh)	Solar Energy Payment Rate (in $/MWh)
1	29,774	22,331	56.02
2	29,625	22,219	56.02
3	29,475	22,106	56.02
4	29,326	21,995	56.02
5	29,177	21,883	56.02
6	29,028	21,771	56.02
7	28,878	21,659	56.02
8	28,729	21,547	56.02
9	28,580	21,435	56.02
10	28,431	21,323	56.02
11	28,281	21,211	56.02
12	28,132	21,099	56.02
13	27,983	20,987	56.02
14	27,834	20,876	56.02
15	27,684	20,763	56.02
16	27,535	20,651	56.02
17	27,386	20,540	56.02
18	27,237	20,428	56.02
19	27,087	20,315	56.02
20	26,938	20,204	56.02
21	26,789	20,092	56.02
22	26,640	19,980	56.02
23	26,491	19,868	56.02
24	26,341	19,756	56.02
25	26,192	19,644	56.02
26	26,043	19,532	56.02
27	25,894	19,421	56.02
28	25,744	19,308	56.02
29	25,595	19,196	56.02
30	25,446	19,085	56.02

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ELECTRIC COMPANY TO CHANGE	§	OF
RATES	§	ADMINISTRATIVE HEARINGS

EL PASO ELECTRIC COMPANY'S RESPONSE TO
FREEPORT-MCMORAN, INC'S FIRST REQUEST FOR INFORMATION
QUESTION NOS. FMI 1-1 THROUGH FMI 1-25

FMI 1-6:

The following Interrogatories pertains to the Direct Testimony of David C. Hawkins.

Referring to page 13, how will EPE ensure that the EV charging stations that will be installed by customers who participate in the TEP program will operate only during off-peak hours?

RESPONSE:

Please reference pages 11-15 of the Direct Testimony of El Paso Electric Company ("EPE") witness David C. Hawkins, which include a description of the technology to be employed to facilitate the implementation of managed charging. The TEP program is not intended to forbid charging during peak hours, but rather to implement the technical capabilities for managed charging that, when coupled with the proper customer rate incentives, should minimize charging during peak hours.

As stated on pages 68-69 of the Direct Testimony of EPE witness Manuel Carrasco, EPE is proposing revisions to the rates and rate structure in the Schedule No. EVC rate schedule that will strongly incentivize the charging of EVs during the hours of least load on EPE's system, from 12:00 A.M. to 8:00 A.M.[1] EPE's other retail rate schedules also include a TOD rate option that EV owner-customers can take service under for the combined energy use of the home or business and the EV charging. EV owner-customers are encouraged to consider service under a TOD rate option because it allows customers to charge their EVs overnight, when EPE's system has capacity available to serve that load, and when savings on monthly electric bills may be maximized by the customers.

Preparer:	Grisel Arizpe	Title:	Supervisor – Emerging Technology Innovation
	Omar Gallegos		Senior Director – Resource Planning Management
Sponsor:	David C. Hawkins	Title:	Vice President – Strategy and Sustainability
	Manuel Carrasco		Manager – Rate Research

[1] Schedule No. EVC is available, on a voluntary basis, to residential and commercial customers that have a separately metered facility dedicated solely for the charging of electric vehicles.

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APPLICATION OF EL PASO ELECTRIC COMPANY TO CHANGE RATES	§ § §	BEFORE THE STATE OFFICE OF ADMINISTRATIVE HEARINGS

EL PASO ELECTRIC COMPANY'S RESPONSE TO FREEPORT-MCMORAN, INC'S FIRST REQUEST FOR INFORMATION QUESTION NOS. FMI 1-1 THROUGH FMI 1-25

FMI 1-7:

The following Interrogatories pertains to the Direct Testimony of David C. Hawkins.

Referring to Exhibit DCH-3, please explain why the interruptible load is treated as a capacity resource rather than a reduction in system demand.

RESPONSE:

The interruptible load is a dispatchable capacity resource in that EPE can call on it as needed and that is being relied on to serve peak load. As a result, it is included in the total resources to meet the peak load and planning reserve margin.

Preparer:	Omar Gallegos	Title:	Senior Director – Resource Planning Management
Sponsor:	David C. Hawkins	Title:	Vice President – Strategy and Sustainability

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APPLICATION OF EL PASO ELECTRIC COMPANY TO CHANGE RATES	§ § §	BEFORE THE STATE OFFICE OF ADMINISTRATIVE HEARINGS

EL PASO ELECTRIC COMPANY'S RESPONSE TO FREEPORT-MCMORAN, INC'S FIRST REQUEST FOR INFORMATION QUESTION NOS. FMI 1-1 THROUGH FMI 1-25

FMI 1-8:

The following Interrogatories pertains to the Direct Testimony of James Schichtl.

Please provide a schedule identifying the estimated and actual rate case expenses, separately for each docket, that EPE is proposing to recover in this proceeding.

RESPONSE:

Please see El Paso Electric Company's response to Staff 6-1, Attachments 1 and 2.

Preparer:	Curtis Hutcheson	Title:	Manager – Regulatory Case Management
Sponsor:	James Schichtl	Title:	Vice President – Regulatory and Governmental Affairs

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APPLICATION OF EL PASO ELECTRIC COMPANY TO CHANGE RATES	§ § §	BEFORE THE STATE OFFICE OF ADMINISTRATIVE HEARINGS

EL PASO ELECTRIC COMPANY'S RESPONSE TO FREEPORT-MCMORAN, INC'S FIRST REQUEST FOR INFORMATION QUESTION NOS. FMI 1-1 THROUGH FMI 1-25

FMI 1-9:

The following Interrogatories pertains to the Direct Testimony of James Schichtl.

Is EPE proposing to recover rate case expenses in base rates or through a separate rider?

RESPONSE:

Consistent with prior cases, El Paso Electric Company would propose to recover rate case expenses through a separate rider; Schedule No. RCES – Rate Case Expense Surcharge.

Preparer: James Schichtl — Title: Vice President – Regulatory and Governmental Affairs

Sponsor: James Schichtl — Title: Vice President – Regulatory and Governmental Affairs

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APPLICATION OF EL PASO ELECTRIC COMPANY TO CHANGE RATES	§ § §	BEFORE THE STATE OFFICE OF ADMINISTRATIVE HEARINGS

EL PASO ELECTRIC COMPANY'S RESPONSE TO FREEPORT-MCMORAN, INC'S FIRST REQUEST FOR INFORMATION QUESTION NOS. FMI 1-1 THROUGH FMI 1-25

FMI 1-10:

The following Interrogatories pertains to the Direct Testimony of James Schichtl.

Is EPE proposing to earn a return on the unamortized portion of rate case expenses? If so, explain the basis for this request.

RESPONSE:

Yes, consistent with EPE's filing in its past two rate proceedings, El Paso Electric Company ("EPE") is proposing to recover carrying cost on a portion of the unamortized balance of rate case expenses. EPE has included in its rate base a regulatory asset for three-fourths of its estimated rate case expense. (See Direct Testimony of Jennifer Borden, page 25.) This is justified because, as is the case with any other cost amortized over a multiyear period, EPE will have incurred the cost and will bear the carrying cost of the expenditure over the amortization period. The time value of money is a universally recognized economic principle.

Preparer: James Schichtl — Title: Vice President – Regulatory and Governmental Affairs

Sponsor: James Schichtl — Title: Vice President – Regulatory and Governmental Affairs

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APPLICATION OF EL PASO	§	BEFORE THE STATE OFFICE
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EL PASO ELECTRIC COMPANY'S RESPONSE TO
FREEPORT-MCMORAN, INC'S FIRST REQUEST FOR INFORMATION
QUESTION NOS. FMI 1-1 THROUGH FMI 1-25

FMI 1-11:

The following Interrogatories pertains to the Direct Testimony of James Schichtl.

Referring to page 39:

a. Explain how EPE identified the rate classes having “the most variation in 2020 as a direct result of the pandemic and are likewise the most likely to see changes in 2022 as conditions return to some degree of pre-pandemic levels” and provide all supporting documents.
b. Does EPE assert that only the rate classes that showed the most variations in 2020 were affected by the pandemic? Explain your response.
c. Does EPE believe that no rate classes were not affected to some degree by the pandemic? If so, identify which rate classes were not affected and provide any analysis documenting how these classes were unaffected.

RESPONSE:

a. El Paso Electric Company (“EPE”) performed a comparison of historical allocation metrics to identify which rate classes had the most variation in 2020. In its analysis, EPE identified the Residential Service and Water Heating rate classes as having significant increases in the energy and demand allocators. Conversely, the Small General Service, General Service and the City & County Service rate classes experienced significant decreases in the energy and demand allocators. Please refer to Exhibit MC-5 for the analysis of historical allocation factors.
b. No, it is likely that all rate classes (with the possible exception of street and area lighting) were affected by the pandemic to varying degrees, either directly or indirectly.
c. EPE’s analysis identifies those classes which showed significant variation in the energy and demand metrics compared with weather -adjusted forecasts. No analysis was done specifically to identify any rate classes that were not affected by the pandemic.

Preparer:	James Schichtl	Title:	Vice President – Regulatory and Governmental Affairs
	Enedina Soto		Manager – Load Research and Data Analytics
Sponsor:	James Schichtl	Title:	Vice President – Regulatory and Governmental Affairs
	George Novela		Director – Economic and Rate Research

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EL PASO ELECTRIC COMPANY'S RESPONSE TO
FREEPORT-MCMORAN, INC'S FIRST REQUEST FOR INFORMATION
QUESTION NOS. FMI 1-1 THROUGH FMI 1-25

FMI 1-12:

The following Interrogatories pertains to the Direct Testimony of Manuel Carrasco.

Referring to pages 15-16:

a. Explain how changes in class allocation factors were determined to most likely be the result of the COVID-19 pandemic shutdown during 2020.

b. Provide any analysis demonstrating how the observed changes in class allocation factors affected the rates of return derived from EPE’s class cost-of-service study in “live” EXCEL format along with supporting workpapers.

RESPONSE:

a. As discussed in page 10 of the Direct Testimony of El Paso Electric Company (“EPE”) witness George Novela, the COVID-19 pandemic resulted in a significant shift in usage patterns over the test year due to business and government office closures and employees working from home as opposed to the office. Energy usage, in combination with other factors, serves as the foundation in the calculation of the class allocation factors. Exhibit MC-5 displays a comparison of energy and certain demand allocation factors over five years, with the change in the 2020 allocation factors strongly correlating to the COVID-19 pandemic. The Residential Service rate class was impacted most profoundly by the change in the allocation factors.

b. N/A. EPE did not perform any analysis demonstrating how the observed changes in class allocation factors affected the rates of return derived from EPE’s class cost-of-service study.

Preparer:	Manuel Carrasco	Title:	Manager – Rate Research
Sponsor:	Manuel Carrasco George Novela	Title:	Manager – Rate Research Director – Economic and Rate Research

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PUC DOCKET NO. 52195

APPLICATION OF EL PASO ELECTRIC COMPANY TO CHANGE RATES	§ § §	BEFORE THE STATE OFFICE OF ADMINISTRATIVE HEARINGS

EL PASO ELECTRIC COMPANY'S RESPONSE TO FREEPORT-MCMORAN, INC'S FIRST REQUEST FOR INFORMATION QUESTION NOS. FMI 1-1 THROUGH FMI 1-25

FMI 1-13:

The following Interrogatories pertains to the Direct Testimony of Manuel Carrasco.

Provide all workpapers supporting the incremental capacity cost shown on page 27, line 6.

RESPONSE:

Please refer to El Paso Electric Company's responses to VS 1-23, UTEP 2-7, and CEP 9.

Preparer: Manuel Carrasco   Title: Manager – Rate Research

Sponsor: Manuel Carrasco   Title: Manager – Rate Research

SOAH DOCKET NO. 473-21-2606
PUC DOCKET NO. 52195

APPLICATION OF EL PASO ELECTRIC COMPANY TO CHANGE RATES	§ § §	BEFORE THE STATE OFFICE OF ADMINISTRATIVE HEARINGS

EL PASO ELECTRIC COMPANY'S RESPONSE TO FREEPORT-MCMORAN, INC'S FIRST REQUEST FOR INFORMATION QUESTION NOS. FMI 1-1 THROUGH FMI 1-25

FMI 1-14:

The following Interrogatories pertains to the Direct Testimony of Manuel Carrasco.

Provide a schedule showing the class rates of return based on EPE's proposed rates in this proceeding and provide supporting workpapers in "live" EXCEL format.

RESPONSE:

El Paso Electric Company ("EPE") did not prepare a schedule showing the class rates of return based on the proposed base revenue allocation by rate class and used for EPE's rate design in this proceeding. However, in response to this request for information, EPE prepared FMI 1-14 Attachment 1, which is a modified version of Schedule P-1.4 filed in this proceeding by replacing the Base and Non-firm revenue amounts of each rate class in that schedule (see lines 4 and 5) with revenue amounts of each rate class from Exhibit MC-4, some of which have been limited by application of a cap or floor. Please note that revenue-related expenses were not reallocated and remain at the same levels by rate class as originally filed in Schedule P-1.4.

Preparer: Manuel Carrasco Title: Manager – Rate Research

Sponsor: Manuel Carrasco Title: Manager – Rate Research

EL PASO ELECTRIC COMPANY
2021 TEXAS RATE CASE FILING
SCHEDULE P-1.4: PROPOSED RATE SCHEDULES / EXISTING RATE CLASSES
SPONSOR: ADRIAN HERNANDEZ
PREPARER: ADRIAN HERNANDEZ
FOR THE TEST YEAR ENDED DECEMBER 31, 2020

MODIFIED SCHEDULE P-1.4 FOR FMI 1-14
PAGE 1 OF 4

USES CAPPED/FLOORED REVENUES FROM EXHIBIT MC-4

Line No.	(a) Description	(b) Test Year Total	(c) Rate 01 Residential	(d) Rate 02 Small General Service	(e) Rate 07 Recreational Lighting	(f) Rate 08 Street Lighting	(g) Rate 09 Traffic Signals	(h) Rate 11-TOU TOU Municipal Pumping	(i) Rate 15 Electric Refining	(j) Rate 22 Irrigation Service
1	Operating Revenues									
2	Sales Revenues									
3	Base Revenues									
4	Base [From Exh. MC-4, page 3, line 12 + line 22 + line 23]	$ 574,206,281	$ 312,165,274	$ 32,508,921	$ 630,549	$ 3,148,411	$ 100,810	$ 10,423,164	$ 2,286,269	$ 571,265
5	Non-firm [From Exh. MC-4, page 3, line 24 + line 26]	4,499,479	2,484,953	213,778	-	-	584	71,721	23,306	4,362
6	Fuel Revenues	80,084,706	31,804,571	3,483,415	47,019	461,227	26,554	2,189,127	965,884	49,123
7	Other Sales For Resale Revenues	65,919,767	26,179,155	2,867,288	38,703	379,648	21,857	1,801,926	795,044	40,435
8	Total Sales Revenues	724,710,233	372,633,953	39,073,403	716,272	3,989,286	149,806	14,485,939	4,070,502	665,184
9	Other Operating Revenues	26,921,992	15,767,809	1,404,624	10,805	50,316	3,275	392,937	109,540	25,903
10	Total Operating Revenues (Cost of Service)	$ 751,632,225	$ 388,401,762	$ 40,478,026	$ 727,077	$ 4,039,602	$ 153,081	$ 14,878,876	$ 4,180,042	$ 691,087
11										
12	Operating Expenses									
13	Operation & Maintenance Expenses									
14	Fuel and Purchased Power									
15	Reconcilable	$ 146,004,473	$ 57,983,726	$ 6,350,703	$ 85,722	$ 840,874	$ 48,412	$ 3,991,054	$ 1,760,928	$ 89,558
16	Non-Reconcilable	1,431,449	780,281	67,574	445	4,362	251	23,283	7,452	1,366
17	Other Operation & Maintenance	243,174,207	137,437,679	13,434,934	205,769	1,327,388	48,154	4,333,673	1,031,770	211,112
18	Total Operation & Maintenance Expenses	390,610,129	196,201,685	19,853,212	291,936	2,172,624	96,816	8,348,009	2,800,150	302,035
19	Regulatory Debits and Credits	2,986,404	1,772,719	174,147	2,844	17,422	508	46,930	11,022	2,747
20	Depreciation & Amortization Expense	99,088,920	56,992,584	5,070,296	111,526	549,116	14,614	1,684,139	356,337	102,825
21	Decommissioning and Accretion Expense	111,981	61,402	5,344	32	296	19	1,813	575	107
22	Taxes Other Than Income Taxes	68,511,555	38,094,474	3,447,816	64,286	345,336	11,819	1,232,096	308,184	65,826
23	Current Income Taxes									
24	Federal	19,368,450	11,924,094	989,309	29,945	84,371	1,800	299,499	23,542	23,476
25	State	2,533,565	1,522,123	127,899	3,714	10,806	276	41,131	4,978	2,968
26	Total Current Income Taxes	21,902,015	13,446,217	1,117,209	33,658	95,178	2,077	340,629	28,520	26,444
27	Deferred Income Taxes									
28	Federal	5,721,725	2,499,659	278,983	2,000	34,820	1,790	138,639	62,264	3,397
29	State	995,013	502,358	48,880	753	5,765	226	20,585	7,157	827
30	Total Deferred Income Taxes	6,716,738	3,002,017	327,863	2,753	40,585	2,015	159,224	69,421	4,223
31	Amortization of Investment Tax Credits	(1,505,971)	(820,902)	(71,092)	(468)	(4,589)	(264)	(24,495)	(7,840)	(1,437)
32	Total Operating Expenses	$ 588,421,771	$ 308,750,196	$ 29,924,794	$ 506,567	$ 3,215,969	$ 127,604	$ 11,788,345	$ 3,566,369	$ 502,770
33										
34	Operating Income (Return)	$ 163,210,454	$ 79,651,566	$ 10,553,233	$ 220,510	$ 823,633	$ 25,477	$ 3,090,531	$ 613,673	$ 188,317

Amounts may not add or tie to other schedules due to rounding.

SCHEDULEL P-1.4
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EL PASO ELECTRIC COMPANY
2021 TEXAS RATE CASE FILING
SCHEDULE P-1.4: PROPOSED RATE SCHEDULES / EXISTING RATE CLASSES
SPONSOR: ADRIAN HERNANDEZ
PREPARER: ADRIAN HERNANDEZ
FOR THE TEST YEAR ENDED DECEMBER 31, 2020

USES CAPPED/FLOORED REVENUES FROM EXHIBIT MC-4

Line No.	(a) Description	(b) Test Year Total	(c) Rate 01 Residential	(d) Rate 02 Small General Service	(e) Rate 07 Recreational Lighting	(f) Rate 08 Street Lighting	(g) Rate 09 Traffic Signals	(h) Rate 11-TOU TOU Municipal Pumping	(i) Rate 15 Electric Refining	(j) Rate 22 Irrigation Service
35	Rate Base									
36	Plant in Service	3,665,210,259	2,103,682,116	183,965,607	4,376,463	20,878,309	525,684	63,065,168	12,883,126	3,881,630
37	Accum Depreciation & Amortization	(1,223,765,542)	(701,537,803)	(61,793,364)	(1,266,613)	(9,296,897)	(180,179)	(20,399,198)	(4,546,797)	(1,251,294)
38	Net Plant In Service	2,441,444,717	1,402,144,313	122,172,243	3,109,850	11,581,412	345,506	42,665,970	8,336,330	2,630,336
39										
40	Additions to Rate Base									
41	CWIP	-	-	-	-	-	-	-	-	-
42	Working Cash	(2,622,625)	(1,480,527)	(144,851)	(2,234)	(14,413)	(523)	(47,056)	(11,203)	(2,278)
43	Fuel Inventory	1,393,806	553,532	60,626	818	8,027	462	38,100	16,810	855
44	Nuclear Fuel	-	-	-	-	-	-	-	-	-
45	Materials & Supplies	48,530,177	27,424,147	2,371,954	67,376	324,604	7,482	880,631	168,997	51,879
46	Prepayments	14,822,703	8,649,512	819,849	14,208	82,157	2,430	240,265	56,417	14,131
47	Coal Reclamation Asset	-	-	-	-	-	-	-	-	-
48	Regulatory Assets	9,523,392	5,469,372	476,560	12,131	45,176	1,348	166,428	32,518	10,260
49	Accumulated Deferred Income Taxes	103,531,111	60,537,165	5,454,207	145,366	601,995	14,949	1,788,596	322,987	109,750
50	Tax Regulatory Assets	12,599,101	7,235,780	630,471	16,048	59,766	1,783	220,178	43,020	13,574
51	Miscellaneous Deferred Debits	3,857,692	2,102,823	182,110	1,200	11,754	675	62,745	20,083	3,680
52	Total Additions to Rate Base	191,635,356	110,491,805	9,850,926	254,914	1,119,067	28,607	3,349,888	649,628	201,851
53										
54	Deductions to Rate Base									
55	Customer Deposits	(5,614,689)	(4,974,188)	(452,540)	(3,496)	(3,175)	(836)	(7,704)	(497)	(2,394)
56	Regulatory Liabilities	-	-	-	-	-	-	-	-	-
57	Accumulated Deferred Income Taxes	(336,181,559)	(192,976,465)	(16,864,281)	(406,405)	(1,855,422)	(48,098)	(5,801,325)	(1,175,386)	(357,178)
58	Tax Regulatory Liabilities	(222,349,082)	(127,697,137)	(11,126,562)	(283,223)	(1,054,751)	(31,466)	(3,885,707)	(759,212)	(239,552)
59	Customer Advances - Construction	(25,033,069)	(15,419,265)	(1,303,007)	(84,905)	(344,577)	(2,612)	(508,919)	(15)	(33,156)
60	Total Deductions from Rate Base	(589,178,399)	(341,067,055)	(29,746,389)	(778,028)	(3,257,925)	(83,012)	(10,203,656)	(1,935,111)	(632,280)
61										
62	Total Rate Base	$ 2,043,901,675	$ 1,171,569,063	$ 102,276,780	$ 2,586,736	$ 9,442,555	$ 291,101	$ 35,812,202	$ 7,050,847	$ 2,199,906
63										
64	Rate of Return on Rate Base	7.985%	6.799%	10.318%	8.525%	8.723%	8.752%	8.630%	8.704%	8.560%
65	Relative Rate of Return	1.000	0.851	1.292	1.068	1.092	1.096	1.081	1.090	1.072
66										
67	Total Revenue Requirement	$ 751,632,225	$ 388,401,762	$ 40,478,026	$ 727,077	$ 4,039,602	$ 153,081	$ 14,878,876	$ 4,180,042	$ 691,087
68	Less: Fuel & Other Sales For Resale Revenues	146,004,473	57,983,726	6,350,703	85,722	840,874	48,412	3,991,054	1,760,928	89,558
69	Less: Other Operating Revenues	26,921,992	15,767,809	1,404,624	10,805	50,316	3,275	392,937	109,540	25,903
70	Less: Base Rate Revenues at Present Rates	536,887,982	275,944,218	33,518,015	462,980	4,046,620	95,746	10,168,889	1,851,685	427,460
71	Equals:									
72	Non-Fuel Base Revenue Increase	$ 41,817,778	$ 38,706,009	$ (795,316)	$ 167,569	$ (898,209)	$ 5,648	$ 325,997	$ 457,890	$ 148,167
73	Proposed Percent Increase	7.789%	14.027%	-2.373%	36.194%	-22.197%	5.899%	3.206%	24.728%	34.662%

Amounts may not add or tie to other schedules due to rounding.

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EL PASO ELECTRIC COMPANY
2021 TEXAS RATE CASE FILING
SCHEDULE P-1.4: PROPOSED RATE SCHEDULES / EXISTING RATE CLASSES
SPONSOR: ADRIAN HERNANDEZ
PREPARER: ADRIAN HERNANDEZ
FOR THE TEST YEAR ENDED DECEMBER 31, 2020

MODIFIED SCHEDULE P-1.4 FOR FMI 1-14
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USES CAPPED/FLOORED REVENUES FROM EXHIBIT MC-4

Line No.	(a) Description	(b) Rate 24 General Service	(c) Rate 25 Large Power	(d) Rate 26 Petroleum Refinery	(e) Rate 28 Area Lighting	(f) Rate 30 Electric Furnace	(g) Rate 31 Military Reservation	(h) Rate 34 Cotton Gin	(i) Rate 41 City and County	(j) WH Water Heating
1	Operating Revenues									
2	Sales Revenues									
3	Base Revenues									
4	Base [From Exh. MC-4, page 3, line 12 + line 22 + line 23]	$ 122,489,587	$ 38,098,209	$ 13,225,193	$ 2,702,987	$ 1,539,309	$ 15,099,043	$ 182,215	$ 18,490,762	$ 544,311
5	Non-firm [From Exh. MC-4, page 3, line 24 + line 26]	950,805	309,197	124,628	-	15,444	157,329	51	142,174	1,148
6	Fuel Revenues	18,549,194	8,621,024	4,673,421	343,211	2,231,320	4,077,775	20,422	2,475,875	65,544
7	Other Sales For Resale Revenues	15,268,316	7,096,185	3,846,812	282,506	1,836,656	3,356,521	16,809	2,037,956	53,951
8	Total Sales Revenues	157,257,902	54,124,615	21,870,054	3,328,704	5,622,729	22,690,667	219,498	23,146,767	664,953
9	Other Operating Revenues	5,296,351	1,626,997	587,933	32,436	72,452	738,975	3,254	750,793	47,592
10	Total Operating Revenues (Cost of Service)	$ 162,554,254	$ 55,751,612	$ 22,457,987	$ 3,361,140	$ 5,695,181	$ 23,429,642	$ 222,752	$ 23,897,560	$ 712,545
11										
12	Operating Expenses									
13	Operation & Maintenance Expenses									
14	Fuel and Purchased Power									
15	Reconcilable	$ 33,817,510	$ 15,717,209	$ 8,520,232	$ 625,717	$ 4,067,976	$ 7,434,296	$ 37,231	$ 4,513,830	$ 119,494
16	Non-Reconcilable	302,382	99,367	40,476	3,245	4,888	50,228	193	45,036	620
17	Other Operation & Maintenance	47,028,789	16,048,054	6,351,999	1,089,547	618,197	6,826,367	58,126	6,751,813	370,836
18	Total Operation & Maintenance Expenses	81,148,681	31,864,630	14,912,707	1,718,510	4,691,062	14,310,890	95,551	11,310,680	490,950
19	Regulatory Debits and Credits	544,608	174,881	62,950	8,416	7,012	73,396	723	80,496	5,581
20	Depreciation & Amortization Expense	19,763,696	6,186,088	1,951,892	507,098	232,722	2,394,888	32,266	2,993,957	144,878
21	Decommissioning and Accretion Expense	23,522	7,710	3,122	214	378	3,878	13	3,505	52
22	Taxes Other Than Income Taxes	13,957,050	4,629,147	1,690,191	274,490	298,459	1,917,604	19,102	2,070,784	84,892
23	Current Income Taxes									
24	Federal	3,854,226	1,022,305	158,976	85,375	(76,822)	299,417	8,424	612,478	28,034
25	State	510,265	143,282	29,594	10,913	(4,639)	45,632	1,062	80,083	3,477
26	Total Current Income Taxes	4,364,491	1,165,587	188,570	96,289	(81,461)	345,049	9,487	692,561	31,511
27	Deferred Income Taxes									
28	Federal	1,233,475	558,343	307,895	18,418	133,454	277,509	876	164,044	6,158
29	State	208,629	79,904	36,232	3,855	12,640	36,050	247	29,743	1,163
30	Total Deferred Income Taxes	1,442,104	638,248	344,127	22,273	146,094	313,560	1,124	193,788	7,322
31	Amortization of Investment Tax Credits	(318,125)	(104,540)	(42,583)	(3,414)	(5,143)	(52,843)	(203)	(47,381)	(652)
32	Total Operating Expenses	$ 120,926,027	$ 44,561,750	$ 19,110,975	$ 2,623,876	$ 5,289,122	$ 19,306,422	$ 158,061	$ 17,298,391	$ 764,533
33										
34	Operating Income (Return)	$ 41,628,226	$ 11,189,862	$ 3,347,012	$ 737,264	$ 406,059	$ 4,123,220	$ 64,690	$ 6,599,169	$ (51,988)

Amounts may not add or tie to other schedules due to rounding.

SCHEDULEL P-1.4
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EL PASO ELECTRIC COMPANY
2021 TEXAS RATE CASE FILING
SCHEDULE P-1.4: PROPOSED RATE SCHEDULES / EXISTING RATE CLASSES
SPONSOR: ADRIAN HERNANDEZ
PREPARER: ADRIAN HERNANDEZ
FOR THE TEST YEAR ENDED DECEMBER 31, 2020

MODIFIED SCHEDULE P-1.4 FOR FMI 1-14
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USES CAPPED/FLOORED REVENUES FROM EXHIBIT MC-4

Line No.	(a) Description	(b) Rate 24 General Service	(c) Rate 25 Large Power	(d) Rate 26 Petroleum Refinery	(e) Rate 28 Area Lighting	(f) Rate 30 Electric Furnace	(g) Rate 31 Military Reservation	(h) Rate 34 Cotton Gin	(i) Rate 41 City and County	(j) WH Water Heating
35	Rate Base									
36	Plant in Service	740,731,569	230,315,390	69,931,330	16,672,182	8,459,050	86,769,056	1,277,118	112,847,872	4,948,590
37	Accum Depreciation & Amortization	(243,649,660)	(76,222,397)	(24,758,071)	(6,306,397)	(2,979,670)	(30,607,746)	(365,338)	(36,859,553)	(1,744,566)
38	Net Plant In Service	497,081,908	154,092,992	45,173,260	10,365,785	5,479,380	56,161,310	911,779	75,988,319	3,204,024
39										
40	Additions to Rate Base									
41	CWIP	-	-	-	-	-	-	-	-	-
42	Working Cash	(506,419)	(173,629)	(68,969)	(11,760)	(6,712)	(74,119)	(624)	(73,313)	(3,996)
43	Fuel Inventory	322,833	150,042	81,337	5,973	38,834	70,970	355	43,090	1,141
44	Nuclear Fuel	-	-	-	-	-	-	-	-	-
45	Materials & Supplies	10,022,798	3,146,830	938,894	269,233	109,329	1,133,846	20,032	1,524,442	67,700
46	Prepayments	2,817,864	901,711	317,320	46,488	36,300	376,633	3,805	419,514	24,098
47	Coal Reclamation Asset	-	-	-	-	-	-	-	-	-
48	Regulatory Assets	1,938,977	601,074	176,208	40,434	21,374	219,070	3,557	296,409	12,498
49	Accumulated Deferred Income Taxes	20,336,372	6,278,110	1,780,677	469,785	210,120	2,167,566	40,841	3,100,348	172,276
50	Tax Regulatory Assets	2,565,196	795,198	233,117	53,493	28,276	289,821	4,705	392,139	16,534
51	Miscellaneous Deferred Debits	814,908	267,790	109,080	8,745	13,174	135,363	521	121,371	1,670
52	Total Additions to Rate Base	38,312,530	11,967,126	3,567,665	882,391	450,695	4,319,149	73,192	5,824,001	291,921
53										
54	Deductions to Rate Base									
55	Customer Deposits	(129,241)	(6,098)	(2,341)	(13,681)	(1,126)	(2,044)	(43)	(15,153)	(131)
56	Regulatory Liabilities	-	-	-	-	-	-	-	-	-
57	Accumulated Deferred Income Taxes	(68,035,652)	(21,142,400)	(6,378,170)	(1,510,260)	(771,905)	(7,916,730)	(118,705)	(10,371,645)	(451,532)
58	Tax Regulatory Liabilities	(45,270,616)	(14,033,672)	(4,114,053)	(944,041)	(499,022)	(5,114,765)	(83,038)	(6,920,465)	(291,799)
59	Customer Advances - Construction	(4,840,840)	(1,313,846)	(89)	(297,642)	(25)	(117)	(23,591)	(780,474)	(79,989)
60	Total Deductions from Rate Base	(118,276,349)	(36,496,016)	(10,494,653)	(2,765,624)	(1,272,078)	(13,033,656)	(225,377)	(18,087,738)	(823,451)
61										
62	Total Rate Base	$ 417,118,090	$ 129,564,102	$ 38,246,272	$ 8,482,552	$ 4,657,997	$ 47,446,804	$ 759,594	$ 63,724,582	$ 2,672,494
63										
64	Rate of Return on Rate Base	9.980%	8.637%	8.751%	8.692%	8.717%	8.690%	8.516%	10.356%	-1.945%
65	Relative Rate of Return	1.250	1.082	1.096	1.088	1.092	1.088	1.067	1.297	(0.244)
66										
67	Total Revenue Requirement	$ 162,554,254	$ 55,751,612	$ 22,457,987	$ 3,361,140	$ 5,695,181	$ 23,429,642	$ 222,752	$ 23,897,560	$ 712,545
68	Less: Fuel & Other Sales For Resale Revenues	33,817,510	15,717,209	8,520,232	625,717	4,067,976	7,434,296	37,231	4,513,830	119,494
69	Less: Other Operating Revenues	5,296,351	1,626,997	587,933	32,436	72,452	738,975	3,254	750,793	47,592
70	Less: Base Rate Revenues at Present Rates	125,887,839	36,242,518	11,080,392	2,932,614	1,206,088	13,155,852	133,020	19,258,401	475,647
71	Equals:									
72	Non-Fuel Base Revenue Increase	$ (2,447,447)	$ 2,164,888	$ 2,269,429	$ (229,627)	$ 348,665	$ 2,100,519	$ 49,247	$ (625,464)	$ 69,812
73	Proposed Percent Increase	-1.944%	5.973%	20.481%	-7.830%	28.909%	15.966%	37.022%	-3.248%	14.677%

Amounts may not add or tie to other schedules due to rounding.

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APPLICATION OF EL PASO	§	BEFORE THE STATE OFFICE
ELECTRIC COMPANY TO CHANGE	§	OF
RATES	§	ADMINISTRATIVE HEARINGS

EL PASO ELECTRIC COMPANY'S RESPONSE TO
FREEPORT-MCMORAN, INC'S FIRST REQUEST FOR INFORMATION
QUESTION NOS. FMI 1-1 THROUGH FMI 1-25

FMI 1-15:

The following Interrogatories pertains to the Direct Testimony of Manuel Carrasco.

Referring to Exhibit MC-4, please provide the derivation of the current base rates revenues in Excel format with all formulas and links intact.

RESPONSE:

Please see El Paso Electric Company's Rate Filing Package Schedule Q-7, Proof of Revenue Statement, pages 1 through 9 of 17, as filed in this proceeding.

Preparer: Manuel Carrasco Title: Manager – Rate Research

Sponsor: Manuel Carrasco Title: Manager – Rate Research

SOAH DOCKET NO. 473-21-2606
PUC DOCKET NO. 52195

APPLICATION OF EL PASO ELECTRIC COMPANY TO CHANGE RATES	§ § §	BEFORE THE STATE OFFICE OF ADMINISTRATIVE HEARINGS

EL PASO ELECTRIC COMPANY'S RESPONSE TO
FREEPORT-MCMORAN, INC'S FIRST REQUEST FOR INFORMATION
QUESTION NOS. FMI 1-1 THROUGH FMI 1-25

FMI 1-16:

The following Interrogatories pertains to the Direct Testimony of Manuel Carrasco.

Please provide the derivation of the proposed base rate revenues, excluding the COVID-19 expense, in Excel format with all formulas and links intact.

RESPONSE:

Please see El Paso Electric Company's Rate Filing Package Schedule Q-7, Proof of Revenue Statement, pages 11 through 16 of 17, as filed in this proceeding. Each rate class' base rate revenue excludes recovery of COVID 19 expense. Recovery of COVID 19 expense is shown as a separate line item titled "Project No. 50664 Asset Surcharge Revenue" in Schedule Q-7, page 16 of 17, line 323.

Preparer: Manuel Carrasco Title: Manager – Rate Research

Sponsor: Manuel Carrasco Title: Manager – Rate Research

SOAH DOCKET NO. 473-21-2606
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APPLICATION OF EL PASO	§	BEFORE THE STATE OFFICE
ELECTRIC COMPANY TO CHANGE	§	OF
RATES	§	ADMINISTRATIVE HEARINGS

EL PASO ELECTRIC COMPANY'S RESPONSE TO
FREEPORT-MCMORAN, INC'S FIRST REQUEST FOR INFORMATION
QUESTION NOS. FMI 1-1 THROUGH FMI 1-25

FMI 1-17:

The following Interrogatories pertains to the Direct Testimony of Adrian Hernandez.

Referring to page 14, please identify and explain the reasons supporting each and every change in EPE's assignment of demand and energy allocators by FERC account as compared to the previous rate case.

RESPONSE:

See Schedule P-13 (line 2 through line 14). El Paso Electric Company followed the NARUC manual in determining the assignment of production operations and maintenance accounts ("O&M") between demand and energy. See FMI 1-17 Attachment 1 which are the pages in the NARUC manual that EPE relied on.

Preparer:	Adrian Hernandez	Title:	Senior Rate Analyst – Rates
Sponsor:	Adrian Hernandez	Title:	Senior Rate Analyst – Rates

Exhibit 4-1
(Continued)
CLASSIFICATION OF PRODUCTION PLANT

FERC Uniform System of Accounts No.	Description	Demand Related	Energy Related

CLASSIFICATION OF EXPENSES[1]
Production Plant

Steam Power Generation Operations

500	Operating Supervision & Engineering	Prorated On Labor[3]	Prorated On Labor[3]
501	Fuel	-	x
502	Steam Expenses	x[4]	x[4]
503-504	Steam From Other Sources & Transfer. Cr.	-	x
505	Electric Expenses	x[4]	x[4]
506	Miscellaneous Steam Pwr Expenses	x	-
507	Rents	x	-

Maintenance

510	Supervision & Engineering	Prorated On Labor[3]	Prorated On Labor[3]
511	Structures	x	-
512	Boiler Plant	-	x
513	Electric Plant	-	x
514	Miscellaneous Steam Plant	-	x

Nuclear Power Generation Operation

517	Operation Supervision & Engineering	Prorated On Labor[3]	Prorated On Labor[3]
518	Fuel	-	x
519	Coolants and Water	x[4]	x[4]
520	Steam Expense	x[4]	x[4]
521-522	Steam From Other Sources & Transfe. Cr.	-	x
523	Electric Expenses	x[4]	x[4]
524	Miscellaneous Nuclear Power Expenses	x	-
525	Rents	x	-

EXHIBIT 4-1

(Continued)

CLASSIFICATION OF EXPENSES [1]

FERC Uniform System of Accounts No.	Description	Demand Related	Energy Related

Maintencance

528	Supervision & Engineering	Prorated on Labor[3]	Prorated on Labor[3]
529	Structures	x	-
530	Reactor Plant Equipment	-	x
531	Electric Plant	-	x
532	Miscellaneous Nuclear Plant	-	x

Hydraulic Power Generation Operation

535	Operation Supervision and Engineering	Prorated on Labor[3]	Prorated on Labor[3]
536	Water for Power	x	-
537	Hydraulic Expenses	x	-
538	Electric Expense	x[4]	x[4]
539	Misc Hydraulic Power Expenses	x	-
540	Rents	x	-

Maintenance

541	Supervision & Engineering	Prorated On Labor[3]	Prorated On Labor[3]
542	Structures	x	-
543	Reservoirs, Dams, and Waterways	x	x
544	Electric Plant	x	x
545	Miscellaneous Hydraulic Plant	x	x

Exhibit 4-1
(Continued)

FERC Uniform System of Account	Description	Demand Related	Energy Related
	CLASSIFICATION OF EXPENSES[1]		
	Other Power Generation Operation		
546, 548-554	All Accounts	x	-
547	Fuel	-	x
	Other Power Supply Expenses		
555	Purchased Power	x[5]	x[5]
556	System Control & Load Dispatch	x	-
557	Other Expenses	x	-

[1] Direct assignment or "exclusive use" costs are assigned directly to the customer class or group that exclusively uses such facilities. The remaining costs are then classified to the respective cost components.

[2] In some instances, a portion of hydro rate base may be classified as energy related.

[3] The classification between demand-related and energy-related costs is carried out on the basis of the relative proportions of labor cost contained in the other accounts in the account grouping.

[4] Classified between demand and energy on the basis of labor expenses and material expenses. Labor expenses are considered demand-related, while material expenses are considered energy-related.

[5] As-billed basis.

The cost accounting approach to classification is based on the argument that plant capacity is fixed to meet demand and that the costs of plant capacity should be assigned to customers on the basis of their demands. Since plant output in KWH varies with system energy requirements, the argument continues, variable production costs should be allocated to customers on a KWH basis.

B. Cost Causation

Cost causation is a phrase referring to an attempt to determine what, or who, is causing costs to be incurred by the utility. For the generation function, cost causation attempts to determine what influences a utility's production plant investment decisions. Cost causation considers: (1) that utilities add capacity to meet critical system planning reliability criteria such as loss of load probability (LOLP), loss of load hours (LOLH),

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APPLICATION OF EL PASO ELECTRIC COMPANY TO CHANGE RATES	§ § §	BEFORE THE STATE OFFICE OF ADMINISTRATIVE HEARINGS

EL PASO ELECTRIC COMPANY'S RESPONSE TO
FREEPORT-MCMORAN, INC'S FIRST REQUEST FOR INFORMATION
QUESTION NOS. FMI 1-1 THROUGH FMI 1-25

FMI 1-18:

The following Interrogatories pertains to the Direct Testimony of Adrian Hernandez.

Does the average and excess method recognize usage that occurs year-round? If not, explain why.

RESPONSE:

Yes. The average and excess methodology does recognize that usage occurs year-round. The average and excess allocators are made up of two components: energy and demand. The annual energy for each rate class is divided by the number of hours in the year and weighted by the load factor. The demand component is weighted by 1 minus the load factor. With a load factor of 0.49 the energy component of the average and excess method accounts for approximately 50% of the calculation.

Preparer:	Juan Cardenas	Title:	Economist – Staff
Sponsor:	George Novela	Title:	Director – Economic and Rate Research

SOAH DOCKET NO. 473-21-2606
PUC DOCKET NO. 52195

APPLICATION OF EL PASO ELECTRIC COMPANY TO CHANGE RATES	§ § §	BEFORE THE STATE OFFICE OF ADMINISTRATIVE HEARINGS

EL PASO ELECTRIC COMPANY'S RESPONSE TO FREEPORT-MCMORAN, INC'S FIRST REQUEST FOR INFORMATION QUESTION NOS. FMI 1-1 THROUGH FMI 1-25

FMI 1-19:

The following Interrogatories pertains to the Direct Testimony of Adrian Hernandez.

Referring to page 31, if fuel and purchased power expenses are offset by fuel factor revenues, explain why these items are being included in the class cost-of-service study?

RESPONSE:

The Rate Filing Package ("RFP") requires that fuel and purchased power expenses be included in the overall cost of service (Schedule A). More specifically, the RFP requires that fuel factor revenues be included in Schedule P-1 (a class cost of service schedule). It is also important to include fuel revenues to correctly reflect revenue related taxes.

Preparer: Adrian Hernandez Title: Senior Rate Analyst – Rates

Sponsor: Adrian Hernandez Title: Senior Rate Analyst – Rates

SOAH DOCKET NO. 473-21-2606
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APPLICATION OF EL PASO ELECTRIC COMPANY TO CHANGE RATES	§ § §	BEFORE THE STATE OFFICE OF ADMINISTRATIVE HEARINGS

EL PASO ELECTRIC COMPANY'S RESPONSE TO FREEPORT-MCMORAN, INC'S FIRST REQUEST FOR INFORMATION QUESTION NOS. FMI 1-1 THROUGH FMI 1-25

FMI 1-20:

The following Interrogatories pertains to the Direct Testimony of Adrian Hernandez.

Referring to Schedule P-1.4, please provide the derivation of base rate revenues for each rate schedule at present rates in Excel format, with all formulas and links intact.

RESPONSE:

Refer to El Paso Electric Company's response to FMI 1-16.

Preparer: Adrian Hernandez Title: Senior Rate Analyst – Rates

Sponsor: Adrian Hernandez Title: Senior Rate Analyst – Rates

SOAH DOCKET NO. 473-21-2606
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APPLICATION OF EL PASO ELECTRIC COMPANY TO CHANGE RATES	§ § §	BEFORE THE STATE OFFICE OF ADMINISTRATIVE HEARINGS

EL PASO ELECTRIC COMPANY'S RESPONSE TO
FREEPORT-MCMORAN, INC'S FIRST REQUEST FOR INFORMATION
QUESTION NOS. FMI 1-1 THROUGH FMI 1-25

FMI 1-21:

The following Interrogatories pertains to the Direct Testimony of John J. Spanos.

Referring to Table JJS-1, please identify the change (in dollars) in net salvage compared to EPE's current net salvage amounts, for each function.

RESPONSE:

When calculating depreciation rates under the remaining life methodology, a specific dollar impact for one parameter cannot be identified precisely. This is because all parameters are blended or intertwined when establishing a remaining life by vintage within an account. Consequently, the attached schedule, FM 1-21 Attachment 1, sets forth an approximation of the portion of the proposed depreciation expense that is related to net salvage as of December 31, 2019 by account.

Preparer: John J. Spanos — Title: President, Gannett Fleming Valuation and Rate Consultants, LLC

Sponsor: John J. Spanos — Title: President, Gannett Fleming Valuation and Rate Consultants, LLC

EL PASO ELECTRIC COMPANY

FM 1-21
AS OF DECEMBER 31, 2019

DEPRECIABLE GROUP	PROPOSED CALCULATED ANNUAL ACCRUAL AMOUNT	CALCULATED ANNUAL ACCRUALS REFLECTING PROPOSED SURVIVOR CURVE AND CURRENTLY APPROVED NET SALVAGE PERCENT	PROPOSED ANNUAL ACCRUAL CHANGE RELATED TO NET SALVAGE
(1)	(2)	(3)	(4)=(2)-(3)
STEAM PRODUCTION PLANT			
311.00 STRUCTURES AND IMPROVEMENTS			
RIO GRANDE UNIT 6	62,880	4,744	58,136
RIO GRANDE UNIT 7	38,120	0	38,120
RIO GRANDE UNIT 8	49,684	34,633	15,051
RIO GRANDE COMMON	281,794	253,237	28,557
NEWMAN UNIT 1	20,984	0	20,984
NEWMAN UNIT 2	116,618	95,839	20,779
NEWMAN UNIT 3	47,086	37,628	9,458
NEWMAN UNIT 4	989,904	852,757	137,147
NEWMAN UNIT 5	519,409	481,612	37,797
NEWMAN COMMON	458,120	430,788	27,332
TOTAL ACCOUNT 311	2,584,599	2,191,238	393,361
312.00 BOILER PLANT EQUIPMENT			
RIO GRANDE UNIT 6	60,345	0	60,345
RIO GRANDE UNIT 7	139,002	0	139,002
RIO GRANDE UNIT 8	454,804	351,414	103,390
RIO GRANDE COMMON	54,061	48,017	6,044
NEWMAN UNIT 1	437,616	263,683	173,933
NEWMAN UNIT 2	1,206,859	1,026,971	179,888
NEWMAN UNIT 3	316,152	256,865	59,287
NEWMAN UNIT 4	256,498	228,171	28,327
NEWMAN UNIT 5	2,221,976	2,057,220	164,756
NEWMAN COMMON	155,686	145,892	9,794
TOTAL ACCOUNT 312	5,302,999	4,378,233	924,766
313.00 ENGINES AND ENGINE-DRIVEN GENERATORS			
NEWMAN UNIT 1	0	0	0
NEWMAN UNIT 4	1,780,675	1,780,675	0
NEWMAN UNIT 5	1,158,343	1,158,343	0
TOTAL ACCOUNT 313	2,939,018	2,939,018	0
314.00 TURBOGENERATOR UNITS			
RIO GRANDE UNIT 6	73,825	1,966	71,859
RIO GRANDE UNIT 7	156,647	99,611	57,036
RIO GRANDE UNIT 8	247,615	212,382	35,233
NEWMAN UNIT 1	1,010,167	964,087	46,080
NEWMAN UNIT 2	879,152	840,772	38,380
NEWMAN UNIT 3	857,278	839,714	17,564
NEWMAN UNIT 4	774,735	725,854	48,881
NEWMAN UNIT 5	1,400,181	1,384,742	15,439
NEWMAN COMMON	0	0	0
TOTAL ACCOUNT 314	5,399,600	5,069,128	330,472
315.00 ACCESSORY ELECTRIC EQUIPMENT			
RIO GRANDE UNIT 6	59,851	23,018	36,833
RIO GRANDE UNIT 7	97,562	70,582	26,980
RIO GRANDE UNIT 8	367,315	324,658	42,657
NEWMAN UNIT 1	24,241	209	24,032
NEWMAN UNIT 2	22,021	0	22,021
NEWMAN UNIT 3	63,543	52,925	10,618
NEWMAN UNIT 4	56,266	3	56,263
NEWMAN UNIT 5	477,670	442,813	34,857
NEWMAN COMMON	3,976	3,751	225
TOTAL ACCOUNT 315	1,172,445	917,959	254,486

EL PASO ELECTRIC COMPANY

FM 1-21
AS OF DECEMBER 31, 2019

DEPRECIABLE GROUP		PROPOSED CALCULATED ANNUAL ACCRUAL AMOUNT	CALCULATED ANNUAL ACCRUALS REFLECTING PROPOSED SURVIVOR CURVE AND CURRENTLY APPROVED NET SALVAGE PERCENT	PROPOSED ANNUAL ACCRUAL CHANGE RELATED TO NET SALVAGE
(1)		(2)	(3)	(4)=(2)-(3)
316.00	MISCELLANEOUS POWER PLANT EQUIPMENT			
	RIO GRANDE UNIT 6	67,097	0	67,097
	RIO GRANDE UNIT 7	40,407	0	40,407
	RIO GRANDE UNIT 8	125,977	87,066	38,911
	RIO GRANDE COMMON	93,906	81,426	12,480
	NEWMAN UNIT 1	44,023	400	43,623
	NEWMAN UNIT 2	56,724	1	56,723
	NEWMAN UNIT 3	84,453	35,847	48,606
	NEWMAN UNIT 4	98,730	0	98,730
	NEWMAN UNIT 5	27,489	24,842	2,647
	NEWMAN ZERO LIQUID DISCHARGE	296,134	274,786	21,348
	NEWMAN COMMON	64,348	59,779	4,569
	TOTAL ACCOUNT 316	999,288	564,147	435,141
TOTAL STEAM PRODUCTION PLANT		**18,397,949**	**16,059,723**	**2,338,226**
GAS TURBINE PLANT				
341.00	STRUCTURES AND IMPROVEMENTS			
	COPPER POWER STATION	16,598	10,546	6,052
	RIO GRANDE UNIT 9	565,958	530,087	35,871
	MONTANA POWER STATION UNIT 1	7,553	7,084	469
	MONTANA POWER STATION UNIT 2	6,155	5,773	382
	MONTANA POWER STATION UNIT 3	4,855	4,554	301
	MONTANA POWER STATION UNIT 4	5,630	5,285	345
	MONTANA POWER STATION COMMON	436,896	406,102	30,794
	SOLAR FACILITIES	4,449	4,449	0
	TOTAL ACCOUNT 341	1,048,094	973,880	74,214
342.00	FUEL HOLDERS			
	COPPER POWER STATION	7,248	2,910	4,338
	RIO GRANDE UNIT 9	95,879	89,598	6,281
	MONTANA POWER STATION COMMON	528,536	491,731	36,805
	TOTAL ACCOUNT 342	631,663	584,239	47,424
343.00	PRIME MOVERS			
	RIO GRANDE UNIT 9	1,838,029	1,716,704	121,325
	MONTANA POWER STATION UNIT 1	2,174,179	2,036,104	138,075
	MONTANA POWER STATION UNIT 2	2,038,250	1,908,792	129,458
	MONTANA POWER STATION UNIT 3	2,028,005	1,903,880	124,125
	MONTANA POWER STATION UNIT 4	2,024,234	1,901,392	122,842
	MONTANA POWER STATION COMMON	983,374	911,162	72,212
	TOTAL ACCOUNT 343	11,086,071	10,378,034	708,037
344.00	GENERATORS			
	COPPER POWER STATION	442,451	364,223	78,228
	RIO GRANDE UNIT 9	231,923	217,180	14,743
	MONTANA POWER STATION UNIT 1	165,547	155,556	9,991
	MONTANA POWER STATION UNIT 2	165,464	155,468	9,996
	MONTANA POWER STATION UNIT 3	163,335	153,393	9,942
	MONTANA POWER STATION UNIT 4	161,282	151,523	9,759
	MONTANA POWER STATION COMMON	2	1	1
	SOLAR FACILITIES	62,103	62,103	0
	TOTAL ACCOUNT 344	1,392,107	1,259,447	132,660

EL PASO ELECTRIC COMPANY

FM 1-21
AS OF DECEMBER 31, 2019

DEPRECIABLE GROUP		PROPOSED CALCULATED ANNUAL ACCRUAL AMOUNT	CALCULATED ANNUAL ACCRUALS REFLECTING PROPOSED SURVIVOR CURVE AND CURRENTLY APPROVED NET SALVAGE PERCENT	PROPOSED ANNUAL ACCRUAL CHANGE RELATED TO NET SALVAGE
(1)		(2)	(3)	(4)=(2)-(3)
345.00	ACCESSORY ELECTRIC EQUIPMENT			
	COPPER POWER STATION	171,293	153,586	17,707
	RIO GRANDE UNIT 9	145,846	136,113	9,733
	MONTANA POWER STATION UNIT 1	87,129	81,750	5,379
	MONTANA POWER STATION UNIT 2	84,673	79,437	5,236
	MONTANA POWER STATION UNIT 3	74,780	70,238	4,542
	MONTANA POWER STATION UNIT 4	63,194	59,395	3,799
	MONTANA POWER STATION COMMON	254,615	235,972	18,643
	SOLAR FACILITIES	8,862	8,862	0
	TOTAL ACCOUNT 345	890,392	825,353	65,039
346.00	MISCELLANEOUS POWER PLANT EQUIPMENT			
	COPPER POWER STATION	43,243	12,405	30,838
	RIO GRANDE UNIT 9	10,363	9,678	685
	MONTANA POWER STATION UNIT 1	7,240	6,782	458
	MONTANA POWER STATION UNIT 2	6,679	6,255	424
	MONTANA POWER STATION UNIT 3	5,557	5,212	345
	MONTANA POWER STATION UNIT 4	5,662	5,314	348
	MONTANA POWER STATION COMMON	16,903	15,586	1,317
	TOTAL ACCOUNT 346	95,647	61,232	34,415
TOTAL GAS TURBINE PLANT		**15,143,974**	**14,082,185**	**1,061,789**
TRANSMISSION PLANT				
350.10	LAND RIGHTS	192,753	192,753	0
350.10	LAND RIGHTS - ISLETA	636,818	636,818	0
352.00	STRUCTURES AND IMPROVEMENTS	144,867	144,867	0
353.00	STATION EQUIPMENT	2,948,962	2,615,419	333,543
354.00	STEEL TOWERS AND FIXTURES	359,891	359,891	0
355.00	WOOD AND STEEL POLES	3,115,165	3,115,165	0
356.00	OVERHEAD CONDUCTORS AND DEVICES	1,579,563	1,412,075	167,488
359.00	ROADS AND TRAILS	45,874	45,874	0
TOTAL TRANSMISSION PLANT		**9,023,893**	**8,522,862**	**501,031**
DISTRIBUTION PLANT				
360.10	LAND RIGHTS	33,963	33,963	0
361.00	STRUCTURES AND IMPROVEMENTS	317,742	317,742	0
362.00	STATION EQUIPMENT	4,102,971	3,819,121	283,850
364.00	POLES, TOWERS AND FIXTURES	5,697,660	4,034,327	1,663,333
365.00	OVERHEAD CONDUCTORS AND DEVICES	2,747,955	2,376,623	371,332
366.00	UNDERGROUND CONDUIT	2,124,461	1,825,374	299,087
367.00	UNDERGROUND CONDUCTORS AND DEVICES	5,117,534	4,207,619	909,915
368.00	LINE TRANSFORMERS	6,629,377	5,828,028	801,349
369.00	SERVICES	779,571	779,571	0
370.00	METERS	1,598,992	1,455,848	143,144
371.00	INSTALLATIONS ON CUSTOMERS' PREMISES	454,004	454,004	0
373.00	STREET LIGHTING AND SIGNAL SYSTEMS	242,324	219,284	23,040
TOTAL DISTRIBUTION PLANT		**29,846,554**	**25,351,504**	**4,495,050**

EL PASO ELECTRIC COMPANY

FM 1-21
AS OF DECEMBER 31, 2019

DEPRECIABLE GROUP		PROPOSED CALCULATED ANNUAL ACCRUAL AMOUNT	CALCULATED ANNUAL ACCRUALS REFLECTING PROPOSED SURVIVOR CURVE AND CURRENTLY APPROVED NET SALVAGE PERCENT	PROPOSED ANNUAL ACCRUAL CHANGE RELATED TO NET SALVAGE
(1)		(2)	(3)	(4)=(2)-(3)
GENERAL PLANT				
390.00	STRUCTURES AND IMPROVEMENTS			
	SYSTEMS OPERATIONS BUILDING	560,769	560,769	0
	STANTON TOWER	896,927	896,927	0
	EASTSIDE OPERATIONS CENTER	898,410	898,410	0
	OTHER STRUCTURES	524,165	524,165	0
	TOTAL ACCOUNT 390	2,880,271	2,880,271	0
391.00	OFFICE FURNITURE AND EQUIPMENT	32,752	32,752	0
393.00	STORES EQUIPMENT	195	195	0
394.00	TOOLS, SHOP AND GARAGE EQUIPMENT	195,583	195,583	0
395.00	LABORATORY EQUIPMENT	347,704	347,704	0
396.00	POWER OPERATED EQUIPMENT	165,782	195,631	(29,849)
397.00	COMMUNICATION EQUIPMENT	2,580,060	2,580,060	0
398.00	MISCELLANEOUS EQUIPMENT	398,847	398,847	0
TOTAL GENERAL PLANT		**6,601,194**	**6,631,043**	**(29,849)**
TOTAL DEPRECIABLE ELECTRIC PLANT		**79,013,564**	**70,647,317**	**8,366,247**

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APPLICATION OF EL PASO	§	BEFORE THE STATE OFFICE
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EL PASO ELECTRIC COMPANY'S RESPONSE TO
FREEPORT-MCMORAN, INC'S FIRST REQUEST FOR INFORMATION
QUESTION NOS. FMI 1-1 THROUGH FMI 1-25

FMI 1-22:

The following Interrogatories pertains to the Direct Testimony of John J. Spanos.

Please explain why the current weighted net salvage percentages for Steam Production Plant and Gas Turbine Plant are improper and identify the main drivers for the change in the weighted net salvage percentages.

RESPONSE:

The current net salvage percentages for Steam and Gas Turbine Plants are not weighted estimates and do not reflect a net salvage component consistent with the recovery of the full service value of an asset. The current net salvage estimates for Steam and Gas Turbine plant are zero percent which does not account for both the interim and terminal portions of net salvage that are expected to be incurred for the assets. To properly estimate net salvage, the costs associated with both interim and terminal retirements must be included in the analysis. Therefore, the main drivers for the changes in net salvage estimates are to properly determine the net salvage related to interim retirements versus terminal retirements which have also changed due to the updated probable retirement dates of some of the facilities.

Preparer: John J. Spanos — Title: President, Gannett Fleming Valuation and Rate Consultants, LLC

Sponsor: John J. Spanos — Title: President, Gannett Fleming Valuation and Rate Consultants, LLC

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APPLICATION OF EL PASO ELECTRIC COMPANY TO CHANGE RATES	§ § §	BEFORE THE STATE OFFICE OF ADMINISTRATIVE HEARINGS

EL PASO ELECTRIC COMPANY'S RESPONSE TO FREEPORT-MCMORAN, INC'S FIRST REQUEST FOR INFORMATION QUESTION NOS. FMI 1-1 THROUGH FMI 1-25

FMI 1-23:

The following Interrogatories pertains to the Direct Testimony of John J. Spanos.

Please explain how you determined the increase in the costs of removal for FERC Account Nos. 353, 356, 364, 367, and 368 and identify the primary drivers for the increase in the negative net salvage percentages?

RESPONSE:

Cost of removal is not an amount that is determined during the conduct of a depreciation study, however, the costs to retire/remove assets in the above accounts has increased due to an increased labor costs to retire these assets. Actual recorded costs of removal for the accounts in the study are analyzed as a relationship to plant retired which is the statistical component of an estimated net salvage percent for each account. The Company's recorded removal costs have increased since the time when the current rates were established. These increasing removal costs result in more negative net salvage compared with previous historic net salvage. Therefore, the increased labor costs to remove plant are the primary driver for increased negative net salvage estimates in the current study.

Preparer: John J. Spanos — Title: President, Gannett Fleming Valuation and Rate Consultants, LLC

Sponsor: John J. Spanos — Title: President, Gannett Fleming Valuation and Rate Consultants, LLC

SOAH DOCKET NO. 473-21-2606
PUC DOCKET NO. 52195

APPLICATION OF EL PASO ELECTRIC COMPANY TO CHANGE RATES	§ § §	BEFORE THE STATE OFFICE OF ADMINISTRATIVE HEARINGS

EL PASO ELECTRIC COMPANY'S RESPONSE TO FREEPORT-MCMORAN, INC'S FIRST REQUEST FOR INFORMATION QUESTION NOS. FMI 1-1 THROUGH FMI 1-25

FMI 1-24:

The following Interrogatories pertains to the Direct Testimony of Cynthia S. Prieto.

Referring to Workpaper A-3 Adjustment 7 COVID-19 Costs, please explain in detail why COVID-19 increased Palo Verde costs by $1.5 million.

RESPONSE:

Please refer to El Paso Electric's response to Staff 5-6 for the detail on why COVID-19 increased Palo Verde costs by $1.5 million.

Preparer: En Li　　Title: Manager – Financial Accounting

Sponsor: Cynthia S. Prieto　　Title: Vice President – Controller

SOAH DOCKET NO. 473-21-2606
PUC DOCKET NO. 52195

APPLICATION OF EL PASO	§	BEFORE THE STATE OFFICE
ELECTRIC COMPANY TO CHANGE	§	OF
RATES	§	ADMINISTRATIVE HEARINGS

EL PASO ELECTRIC COMPANY'S RESPONSE TO
FREEPORT-MCMORAN, INC'S FIRST REQUEST FOR INFORMATION
QUESTION NOS. FMI 1-1 THROUGH FMI 1-25

FMI 1-25:

The following Interrogatories pertains to the Direct Testimony of Cynthia S. Prieto.

Referring to Workpaper G-7.9(a).3, tab WP1a Excess TCJA for Rider, please explain why EPE proposes to amortize the unprotected excess ADIT over four years for assets that have expected remaining lives that exceed four years?

RESPONSE:

As explained in pages 27 and 28 of the Direct Testimony of El Paso Electric Company ("EPE") witness Cynthia S. Prieto, EPE is proposing the use of the "Reverse South Georgia" ("RSG") method to amortize unprotected excess ADIT related to the TCJA. The RSG method calculates the weighted average life of the underlying ADIT that resulted in the unprotected excess ADIT. In this case, the weighted average life of the unprotected excess ADIT is four years, as calculated on Workpaper G-7.9(a).03, tab WP1a Excess TCJA for Rider.

Preparer: Tammy Henderson Title: Manager – Tax

Sponsor: Cynthia S. Prieto Title: Vice President – Controller

The following files are not convertible:

FMI 01-02_Attachment 1.xlsx
FMI 01-03_Attachment 01.xlsx
FMI 01-03_Attachment 02.xlsx
FMI 01-03_Attachment 03.xlsx
FMI 01-05_Attachment 01.xlsx
FMI 01-05_Attachment 02.xlsx
FMI 01-14_Attachment 01.xlsx
FMI 01-21_Attachment 01.xlsx

Please see the ZIP file for this Filing on the PUC Interchange in order to access these files.

Contact centralrecords@puc.texas.gov if you have any questions.