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Electricity Market Module

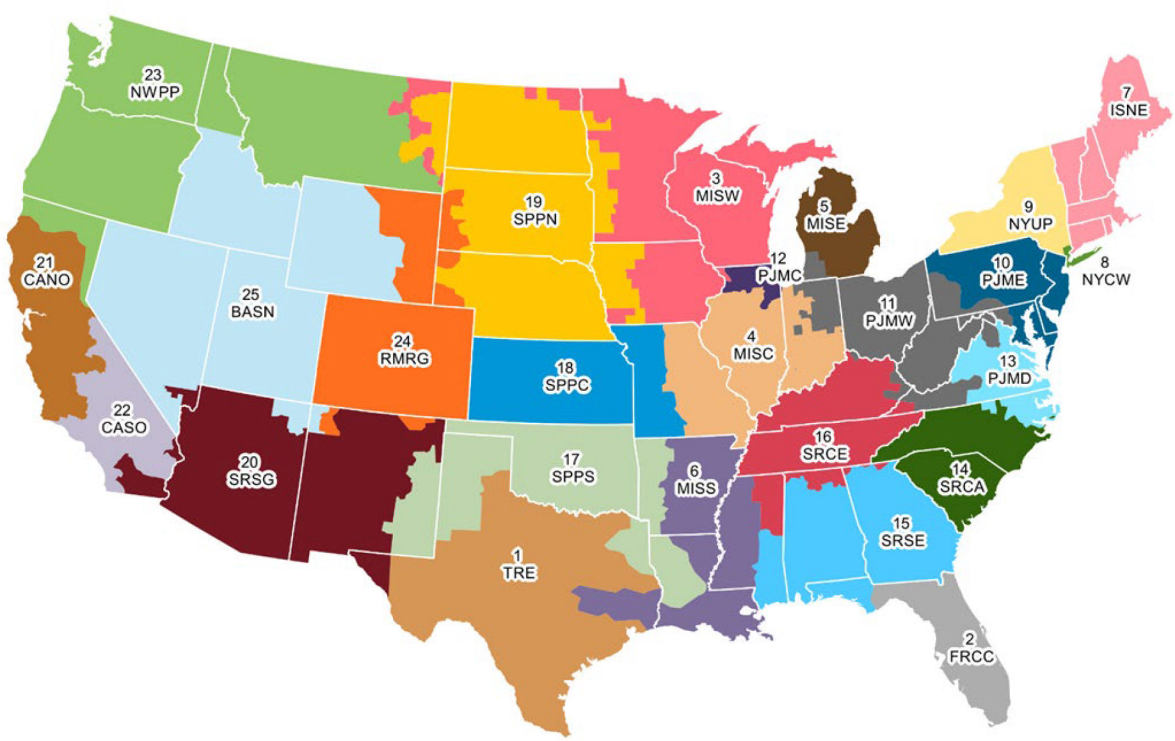
The Electricity Market Module (EMM) in the U.S. Energy Information Administration's (EIA) National Energy Modeling System (NEMS) is composed of four submodules: electricity load and demand, electricity capacity planning, electricity fuel dispatching, and electricity finance and pricing. The EMM also includes nonutility capacity and generation as well as electricity transmission and trade. The EIA publication, *The Electricity Market Module of the National Energy Modeling System: Model Documentation 2020, DOE/EIA-M068* (*2020*), describes the EMM.

Based on fuel prices and electricity demands provided by the other modules of NEMS, the EMM determines the most economical way to supply electricity within environmental and operational constraints. Each EMM submodule includes assumptions about the operations of the electricity sector and the costs of various options. This section describes the model parameters and assumptions used in the EMM and discusses legislation and regulations that EIA incorporates in the EMM.

EMM regions

EIA last updated the supply regions used in the EMM for its *Annual Energy Outlook 2020* (AEO2020) to account for changes in Independent System Operator (ISO) and Regional Transmission Organization (RTO) composition and to better represent U.S. power markets. The regions follow North American Electric Reliability Corporation (NERC) assessment region boundaries and ISO region boundaries (as of early 2019), and subregions are based on regional pricing zones, as shown in Figure 1 and described in Table 1.

Figure 1. Electricity Market Module regions



Source: U.S. Energy Information Administration

Table 3. Cost and performance characteristics of new central station electricity generating technologies

Technology	First available year[1]	Size (MW)	Lead time (years)	Base overnight cost[2] (2020 $/kW)	Techno-logical optimism factor[3]	Total overnight cost[4,5] (2020 $/kW)	Variable O&M[6] (2020 $/MWh)	Fixed O&M (2020$/ kW-yr)	Heat rate[7] (Btu/kWh)
Ultra-supercritical coal (USC)	2024	650	4	3,672	1.00	3,672	4.52	40.79	8,638
USC with 30% carbon capture and sequestration (CCS)	2024	650	4	4,550	1.01	4,595	7.11	54.57	9,751
USC with 90% CCS	2024	650	4	5,861	1.02	5,978	11.03	59.85	12,507
Combined-cycle—single shaft	2023	418	3	1,082	1.00	1,082	2.56	14.17	6,431
Combined-cycle—multi shaft	2023	1,083	3	957	1.00	957	1.88	12.26	6,370
Combined-cycle with 90% CCS	2023	377	3	2,471	1.04	2,570	5.87	27.74	7,124
Internal combustion engine	2022	21	2	1,813	1.00	1,813	5.72	35.34	8,295
Combustion turbine—aeroderivative[8]	2022	105	2	1,169	1.00	1,169	4.72	16.38	9,124
Combustion turbine—industrial frame	2022	237	2	709	1.00	709	4.52	7.04	9,905
Fuel cells	2023	10	3	6,277	1.09	6,866	0.59	30.94	6,469
Nuclear—light water reactor	2026	2,156	6	6,034	1.05	6,336	2.38	122.26	10,455
Nuclear—small modular reactor	2028	600	6	6,183	1.10	6,802	3.02	95.48	10,455
Distributed generation—base	2023	2	3	1,560	1.00	1,560	8.65	19.46	8,935
Distributed generation—peak	2022	1	2	1,874	1.00	1,874	8.65	19.46	9,921
Battery storage	2021	50	1	1,165	1.00	1,165	0.00	24.93	NA
Biomass	2024	50	4	4,077	1.00	4,078	4.85	126.36	13,500
Geothermal[9, 10]	2024	50	4	2,772	1.00	2,772	1.17	137.50	8,946
Municipal solid waste—landfill gas	2023	36	3	1,566	1.00	1,566	6.23	20.20	8,513
Conventional hydropower[10]	2024	100	4	2,769	1.00	2,769	1.40	42.01	NA
Wind[5]	2023	200	3	1,846	1.00	1,846	0.00	26.47	NA
Wind offshore[9]	2024	400	4	4,362	1.25	5,453	0.00	110.56	NA
Solar thermal[9]	2023	115	3	7,116	1.00	7,116	0.00	85.82	NA
Solar photovoltaic (PV) with tracking[5, 9, 11]	2022	150	2	1,248	1.00	1,248	0.00	15.33	NA
Solar PV with storage[9, 11]	2022	150	2	1,612	1.00	1,612	0.00	32.33	NA

[1] Represents the first year that a new unit could become operational.
[2] Base cost includes project contingency costs.
[3] The technological optimism factor is applied to the first four units of a new, unproven design; it reflects the demonstrated tendency to underestimate actual costs for a first-of-a-kind unit.
[4] Overnight capital cost includes contingency factors and excludes regional multipliers (except as noted for wind and solar PV) and learning effects. Interest charges are also excluded. The capital costs represent current costs for plants that would come online in 2021.
[5] Total overnight cost for wind and solar PV technologies in the table are the average input value across all 25 electricity market regions, as weighted by the respective capacity of that type installed during 2019 in each region to account for the substantial regional variation in wind and solar costs (as shown in Table 4). The input value used for onshore wind in AEO2021 was $1,268 per kilowatt (kW) and for solar PV with tracking it was $1,232/kW, which represents the cost of building a plant excluding regional factors. Region-specific factors contributing to the substantial regional variation in cost include differences in typical project size across regions, accessibility of resources, and variation in labor and other construction costs throughout the country.
[6] O&M = Operations and maintenance.
[7] The nuclear average heat rate is the weighted average tested heat rate for nuclear units as reported on the Form EIA-860, *Annual Electric Generator Report*. No heat rate is reported for battery storage because it is not a primary conversion technology; conversion losses are accounted for when the electricity is first generated; electricity-to-storage losses are accounted for through the additional demand for electricity required to meet load. For hydropower, wind, solar, and geothermal technologies, no heat rate is reported because the power is generated without fuel combustion and no set British thermal unit conversion factors exist. The model calculates the average heat rate for fossil-fuel generation in each year to report primary energy consumption displaced for these resources.
[8] Combustion turbine aeroderivative units can be built by the model before 2022, if necessary, to meet a region's reserve margin.
[9] Capital costs are shown before investment tax credits are applied.
[10] Because geothermal and hydropower cost and performance characteristics are specific for each site, the table entries show the cost of the least expensive plant that could be built in the Northwest region for hydro and Great Basin region for geothermal, where most of the proposed sites are located.
[11] Costs and capacities are expressed in terms of net AC (alternating current) power available to the grid for the installed capacity.
Sources: Input costs are primarily based on a report provided by external consultants: Sargent & Lundy, December 2019. Hydropower site costs for non-powered dams were most recently updated for AEO2018 using data from Oak Ridge National Lab

Table 4. Total overnight capital costs of new electricity generating technologies by region

2020 dollars per kilowatt

Technology	1 TRE	2 FRCC	3 MISW	4 MISC	5 MISE	6 MISS	7 ISNE	8 NYCW	9 NYUP	10 PJME	11 PJMW	12 PJMC	13 PJMD
Ultra-supercritical coal (USC)	3,412	3,512	3,838	3,939	3,985	3,531	4,255	NA	4,159	4,293	3,662	4,614	3,952
USC with 30% CCS	4,308	4,422	4,774	4,903	4,942	4,450	5,272	NA	5,167	5,306	4,594	5,640	4,939
USC with 90% CCS	5,642	5,786	6,173	6,381	6,387	5,841	6,764	NA	6,590	6,775	5,956	7,214	6,331
CC—single shaft	977	997	1,112	1,122	1,151	1,006	1,298	1,722	1,301	1,300	1,078	1,302	1,241
CC—multi shaft	851	872	989	1,006	1,032	882	1,134	1,554	1,115	1,140	934	1,196	1,054
CC with 90% CCS	2,410	2,432	2,599	2,605	2,645	2,455	2,729	3,091	2,667	2,707	2,489	2,822	2,593
Internal combustion engine	1,705	1,743	1,862	1,936	1,915	1,766	1,984	2,487	1,909	1,985	1,778	2,164	1,847
CT—aeroderivative	1,034	1,056	1,223	1,226	1,263	1,077	1,315	1,684	1,269	1,308	1,122	1,437	1,190
CT—industrial frame	626	639	742	746	768	653	801	1,033	771	797	680	877	723
Fuel cells	6,589	6,691	6,997	7,299	7,160	6,804	7,428	8,745	7,126	7,364	6,784	7,851	6,993
Nuclear—light water reactor	5,981	6,110	6,450	7,036	6,786	6,309	7,177	NA	6,696	7,013	6,199	7,711	6,451
Nuclear—small modular reactor	6,338	6,486	7,066	7,369	7,366	6,567	7,608	NA	7,246	7,623	6,648	8,506	6,904
Distributed generation—base	1,408	1,437	1,603	1,618	1,659	1,450	1,871	2,482	1,876	1,874	1,554	1,877	1,788
Distributed generation—peak	1,657	1,692	1,959	1,965	2,024	1,727	2,108	2,698	2,034	2,096	1,798	2,303	1,907
Battery storage	1,165	1,168	1,151	1,207	1,168	1,192	1,201	1,196	1,169	1,173	1,162	1,177	1,173
Biomass	3,784	3,887	4,208	4,348	4,358	3,919	4,842	6,572	4,857	4,942	4,156	4,951	4,736
Geothermal	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
MSW—landfill gas	1,476	1,508	1,606	1,673	1,652	1,530	1,713	2,133	1,647	1,711	1,538	1,861	1,596
Conventional hydropower	4,040	4,935	1,963	1,305	2,657	3,932	1,819	NA	3,722	3,866	3,370	NA	3,420
Wind	2,477	NA	1,395	1,268	1,518	1,268	1,680	NA	2,049	1,680	1,268	1,846	1,750
Wind offshore	5,325	6,390	6,304	NA	6,529	NA	6,360	5,486	6,652	6,097	4,985	7,219	5,679
Solar thermal	6,865	6,969	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Solar PV with tracking	1,214	1,191	1,232	1,278	1,264	1,202	1,276	1,501	1,264	1,301	1,229	1,341	1,226
Solar PV with storage	1,561	1,577	1,624	1,677	1,653	1,593	1,687	1,917	1,656	1,690	1,588	1,757	1,643

Technology	14 SRCA	15 SRSE	16 SRCE	17 SPPS	18 SPPC	19 SPPN	20 SRSG	21 CANO	22 CASO	23 NWPP	24 RMRG	25 BASN
Ultra-supercritical coal (USC)	3,533	3,586	3,634	3,557	3,779	3,597	3,748	NA	NA	3,971	3,712	3,873
USC with 30% CCS	4,454	4,496	4,563	4,466	4,713	4,508	4,703	NA	NA	4,942	4,653	4,828
USC with 90% CCS	5,852	5,904	5,974	5,821	6,117	5,863	6,098	NA	NA	6,398	6,008	6,287
CC—single shaft	993	1,005	1,036	1,004	1,066	995	978	1,432	1,399	1,138	922	996
CC—multi shaft	872	883	915	882	947	874	842	1,259	1,225	987	793	889
CC with 90% CCS	2,424	2,437	2,492	2,428	2,509	2,391	2,212	2,774	2,743	2,559	2,080	2,336
Internal combustion engine	1,776	1,781	1,812	1,763	1,858	1,781	1,798	2,155	2,116	1,916	1,775	1,900
CT—aeroderivative	1,071	1,081	1,121	1,079	1,155	1,087	981	1,381	1,347	1,211	949	1,082
CT— industrial frame	649	655	680	654	701	658	594	844	822	737	575	657
Fuel cells	6,853	6,848	6,942	6,728	7,010	6,789	6,884	7,887	7,796	7,209	6,751	7,191
Nuclear—light water reactor	6,390	6,340	6,546	6,135	6,487	6,133	6,361	NA	NA	6,885	6,162	6,893
Nuclear—small modular reactor	6,600	6,651	6,802	6,584	6,993	6,640	6,728	NA	NA	7,285	6,656	7,235
Distributed generation—base	1,432	1,449	1,493	1,448	1,536	1,434	1,409	2,064	2,017	1,641	1,328	1,436
Distributed generation—peak	1,717	1,732	1,797	1,729	1,852	1,741	1,572	2,213	2,158	1,941	1,521	1,734
Battery storage	1,203	1,186	1,201	1,159	1,167	1,153	1,180	1,213	1,216	1,193	1,155	1,201
Biomass	3,934	3,963	4,016	3,937	4,183	4,020	4,305	5,515	5,390	4,451	4,265	4,265
Geothermal	NA	NA	NA	NA	NA	NA	2,825	2,802	2,269	2,742	NA	2,772
MSW—landfill gas	1,539	1,541	1,568	1,525	1,605	1,539	1,555	1,857	1,825	1,655	1,534	1,642
Conventional hydropower	1,904	4,130	2,135	4,086	1,722	1,619	3,282	3,473	3,344	2,769	3,306	3,613
Wind	1,512	1,713	1,268	1,395	1,395	1,395	1,395	2,799	2,418	1,848	1,395	1,395
Wind offshore	4,907	NA	NA	NA	NA	NA	NA	8,224	8,628	6,170	NA	NA
Solar thermal	NA	NA	NA	6,934	7,203	6,864	7,193	8,473	8,367	7,656	6,912	7,671
Solar PV with tracking	1,251	1,188	1,228	1,190	1,237	1,199	1,211	1,348	1,341	1,241	1,225	1,236

Solar PV with storage	1,604	1,588	1,607	1,577	1,628	1,594	1,602	1,756	1,751	1,656	1,595	1,653

NA = not available; plant type cannot be built in the region because of a lack of resources, sites, or specific state legislation.

USC = ultra-supercritical, CCS = carbon capture and sequestration, CC = combined cycle, CT = combustion turbine, PV = photovoltaic, MSW = municipal solid waste

Electricity Market Module region map

Source: U.S. Energy Information Administration, Office of Electricity, Coal, Nuclear and Renewables Analysis

Notes: Costs include contingency factors and regional cost and ambient conditions multipliers. Interest charges are excluded. The costs are shown before investment tax credits are applied.

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Figure 1. Electricity Market Module regions

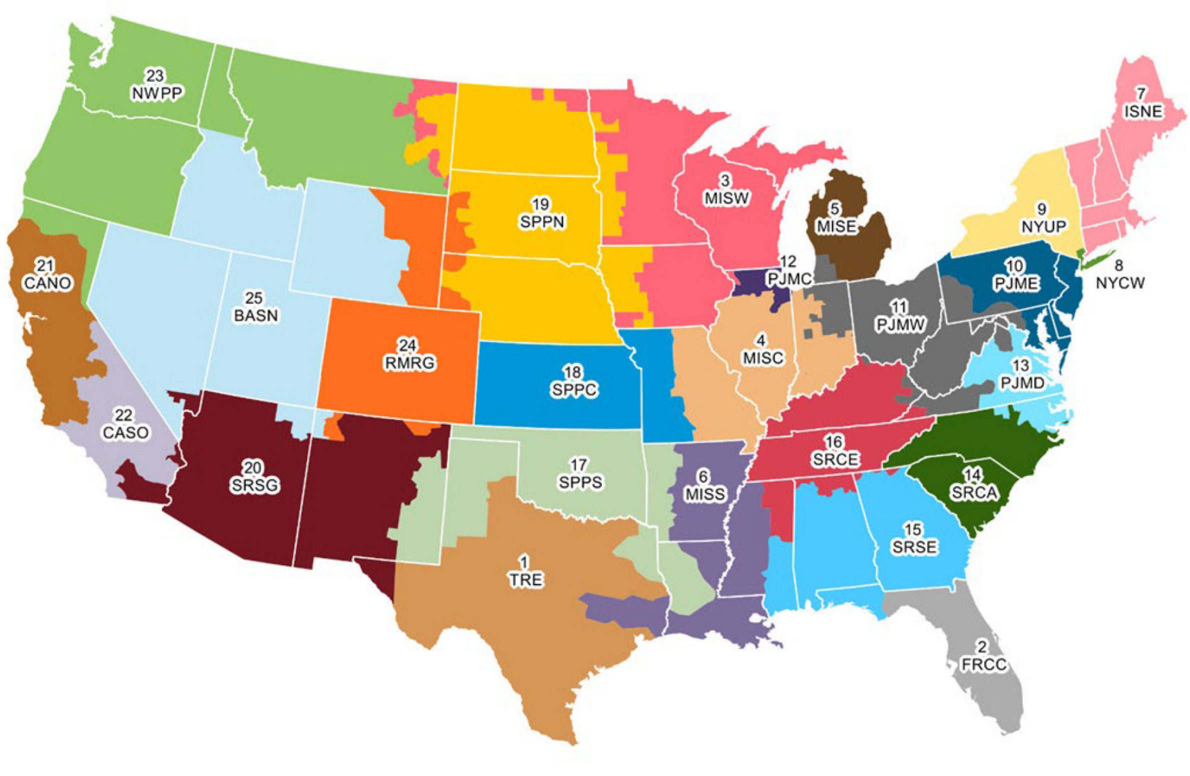

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Table 3. Cost and performance characteristics of new central station electricity generating technologies

Technology	First available year[1]	Size (MW)	Lead time (years)	Base overnight cost[2] (2019 $/kW)	Techno-logical optimism factor[3]	Total overnight cost[4,5] (2019 $/kW)	Variable O&M[6] (2019 $/MWh)	Fixed O&M (2019$/ kW-yr)	Heat rate[7] (Btu/kWh)
Ultra-supercritical coal (USC)	2023	650	4	3,661	1.00	3,661	4.48	40.41	8,638
USC with 30% carbon capture and sequestration (CCS)	2023	650	4	4,539	1.03	4,652	7.05	54.07	9,751
USC with 90% CCS	2023	650	4	5,851	1.03	5,997	10.93	59.29	12,507
Combined-cycle—single shaft	2022	418	3	1,079	1.00	1,079	2.54	14.04	6,431
Combined-cycle—multi shaft	2022	1,083	3	954	1.00	954	1.86	12.15	6,370
Combined-cycle with 90% CCS	2022	377	3	2,470	1.04	2,569	5.82	27.48	7,124
Internal combustion engine	2021	21	2	1,802	1.00	1,802	5.67	35.01	8,295
Combustion turbine—aeroderivative[8]	2021	105	2	1,170	1.00	1,170	4.68	16.23	9,124
Combustion turbine—industrial frame	2021	237	2	710	1.00	710	4.48	6.97	9,905
Fuel cells	2022	10	3	6,671	1.10	7,339	0.59	30.65	6,469
Advanced nuclear	2025	2,156	6	6,016	1.05	6,317	2.36	121.13	10,461
Distributed generation—base	2022	2	3	1,555	1.00	1,555	8.57	19.28	8,946
Distributed generation—peak	2021	1	2	1,868	1.00	1,868	8.57	19.28	9,934
Battery storage	2020	50	1	1,383	1.00	1,383	0.00	24.70	NA
Biomass	2023	50	4	4,080	1.01	4,104	4.81	125.19	13,500
Geothermal[9,10]	2023	50	4	2,680	1.00	2,680	1.16	113.29	9,156
Municipal solid waste—landfill gas	2022	36	3	1,557	1.00	1,557	6.17	20.02	8,513
Conventional hydropower[10]	2023	100	4	2,752	1.00	2,752	1.39	41.63	NA
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Wind offshore[9]	2023	400	4	4,356	1.25	5,446	0.00	109.54	NA
Solar thermal[9]	2022	115	3	7,191	1.00	7,191	0.00	85.03	NA
Solar photovoltaic —tracking[5,9,11]	2021	150	2	1,331	1.00	1,331	0.00	15.19	NA

[1] Represents the first year that a new unit could become operational.
[2] Base cost includes project contingency costs.
[3] The technological optimism factor is applied to the first four units of a new, unproven design; it reflects the demonstrated tendency to underestimate actual costs for a first-of-a-kind unit.
[4] Overnight capital cost includes contingency factors and excludes regional multipliers (except as noted for wind and solar PV) and learning effects. Interest charges are also excluded. The capital costs represent current costs for plants that would come online in 2020.
[5] Wind and solar PV technologies' total overnight cost in the table shows the average input value across all 25 electricity market regions, as weighted by the respective capacity of that type installed during 2018 in each region to account for the substantial regional variation in wind and solar costs (as shown in Table 4). The input value used for onshore wind in AEO2020 was $1,260 per kilowatt (kW) and for solar PV with tracking it was $1,307/kW, which represents the cost of building a plant excluding regional factors. Region-specific factors contributing to the substantial regional variation in cost include differences in typical project size across regions, accessibility of resources, and variation in labor and other construction costs through the country.
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Table 4. Total overnight capital costs of new electricity generating technologies by region

2019 dollars per kilowatt

Technology	1 TRE	2 FRCC	3 MISW	4 MISC	5 MISE	6 MISS	7 ISNE	8 NYCW	9 NYUP	10 PJME	11 PJMW	12 PJMC	13 PJMD
Ultra-supercritical coal (USC)	3,402	3,523	3,892	3,923	3,973	3,521	4,242	NA	4,146	4,280	3,651	4,601	3,940
USC with 30% CCS	4,362	4,499	4,906	4,959	5,004	4,506	5,338	NA	5,231	5,372	4,651	5,710	5,000
USC with 90% CCS	5,660	5,826	6,273	6,395	6,407	5,860	6,785	NA	6,611	6,796	5,975	7,236	6,350
CC—single shaft	974	1,011	1,125	1,119	1,147	1,003	1,294	1,717	1,298	1,296	1,075	1,299	1,237
CC—multi shaft	848	886	1,003	1,004	1,030	880	1,131	1,549	1,112	1,137	931	1,192	1,051
CC with 90% CCS	2,409	2,466	2,614	2,604	2,644	2,454	2,728	3,090	2,666	2,706	2,488	2,820	2,592
Internal combustion engine	1,695	1,744	1,871	1,924	1,903	1,756	1,972	2,472	1,898	1,973	1,768	2,150	1,836
CT—aeroderivative	1,035	1,087	1,242	1,227	1,264	1,078	1,316	1,685	1,270	1,309	1,122	1,438	1,191
CT—industrial frame	626	658	754	746	769	653	801	1,034	772	797	680	878	723
Fuel cells	7,042	7,191	7,531	7,793	7,653	7,272	7,939	9,346	7,617	7,871	7,251	8,392	7,474
Advanced nuclear	5,963	6,120	6,494	7,008	6,766	6,290	7,156	NA	6,676	6,992	6,180	7,688	6,432
Dist. generation—base	1,384	1,425	1,536	1,597	1,581	1,390	1,778	2,540	1,799	1,862	1,596	1,597	1,358
Dist. Generation—peak	1,795	1,864	1,847	1,905	1,852	1,818	1,940	2,631	1,915	2,055	1,894	1,899	1,767
Battery storage	1,383	1,385	1,363	1,431	1,386	1,415	1,425	1,420	1,388	1,392	1,379	1,397	1,392
Biomass	3,808	3,944	4,292	4,371	4,385	3,944	4,873	6,614	4,888	4,974	4,182	4,982	4,766
Geothermal	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
MSW—landfill gas	1,467	1,509	1,613	1,662	1,642	1,520	1,702	2,120	1,637	1,701	1,528	1,850	1,587
Conventional hydropower	NA	4,905	1,609	NA	NA	NA	1,808	NA	3,699	3,843	3,530	3,349	3,399
Wind	1,231	NA	1,260	1,259	1,509	1,260	1,670	NA	2,037	1,670	1,260	1,668	1,739
Wind offshore	5,319	5,446	5,446	NA	6,521	NA	5,446	5,478	6,643	5,446	5,446	7,210	5,672
Solar thermal	6,937	7,049	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Solar PV— tracking	1,289	1,265	1,318	1,355	1,341	1,275	1,354	1,593	1,341	1,381	1,304	1,423	1,301

Technology	14 SRCA	15 SRSE	16 SRCE	17 SPPS	18 SPPC	19 SPPN	20 SRSG	21 CANO	22 CASO	23 NWPP	24 RMRG	25 BASN
Ultra-supercritical coal (USC)	3,522	3,615	3,593	3,546	3,768	3,586	3,737	NA	NA	3,959	3,701	3,861
USC with 30% CCS	4,509	4,610	4,578	4,522	4,772	4,564	4,761	NA	NA	5,004	4,711	4,888
USC with 90% CCS	5,871	5,976	5,951	5,839	6,136	5,881	6,117	NA	NA	6,418	6,027	6,306
CC—single shaft	991	1,003	1,023	1,001	1,063	992	975	1,451	1,374	1,135	919	994
CC—multi shaft	869	883	901	879	944	872	839	1,278	1,202	985	790	887
CC with 90% CCS	2,424	2,425	2,477	2,427	2,508	2,390	2,211	2,802	2,708	2,558	2,079	2,335
Internal combustion engine	1,765	1,785	1,785	1,752	1,847	1,770	1,787	2,157	2,098	1,904	1,764	1,888
CT—aeroderivative	1,072	1,081	1,109	1,080	1,156	1,087	981	1,406	1,324	1,212	950	1,082
CT— industrial frame	649	656	673	654	702	659	594	860	808	737	575	658
Fuel cells	7,325	7,372	7,368	7,191	7,492	7,256	7,357	8,480	8,305	7,705	7,216	7,686
Advanced nuclear	6,371	6,382	6,438	6,116	6,468	6,114	6,342	NA	NA	6,865	6,143	6,872
Dist. Generation—base	1,358	1,418	1,409	1,460	1,515	1,521	1,555	1,933	1,933	1,569	1,638	1,569
Dist. Generation—peak	1,767	1,868	1,786	1,850	1,888	1,848	2,157	2,145	2,145	1,956	2,246	1,956
Battery storage	1,428	1,408	1,419	1,376	1,385	1,368	1,400	1,440	1,441	1,416	1,371	1,426
Biomass	3,959	4,033	4,009	3,962	4,209	4,045	4,333	5,616	5,389	4,480	4,292	4,292
Geothermal	NA	NA	NA	NA	NA	NA	2,817	2,794	2,262	2,734	NA	2,680
MSW—landfill gas	1,529	1,545	1,545	1,515	1,595	1,529	1,545	1,859	1,809	1,645	1,525	1,632
Conventional hydropower	1,892	4,105	1,297	NA	1,711	1,971	3,262	3,323	4,478	2,752	3,286	3,591
Wind	1,503	1,703	1,260	1,260	1,260	1,260	1,260	2,782	2,185	1,670	1,260	1,260
Wind offshore	4,901	NA	NA	NA	NA	NA	NA	7,126	5,446	5,446	NA	NA
Solar thermal	NA	NA	NA	7,007	7,279	6,936	7,268	8,614	8,430	7,736	6,984	7,751
Solar PV—tracking	1,327	1,284	1,282	1,263	1,313	1,272	1,285	1,443	1,409	1,317	1,300	1,312

Notes: Costs include contingency factors and regional cost and ambient conditions multipliers. Interest charges are excluded. The costs are shown before investment tax credits are applied.

NA = not available; plant type cannot be built in the region because of a lack of resources, sites, or specific state legislation.

USC = ultra-supercritical, CCS = carbon capture and sequestration, CC = combined cycle, CT = combustion turbine, PV = photovoltaic, MSW = municipal solid waste

Electricity Market Module region map

Source: U.S. Energy Information Administration, Office of Electricity, Coal, Nuclear and Renewables Analysis

Updated March 2020: EIA changed regional costs for solar thermal to NA in regions where resource quality may be insufficient to support significant development of solar thermal power.

The following files are not convertible:

Exhibit JP-R1.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.

SETTLEMENT AGREEMENT

This Settlement Agreement ("Agreement") is made and entered into by and between El Paso Electric Company ("EPE"), Chaparral Community Coalition for Health and the Environment ("Chaparral Community Coalition"), and Sierra Club and institutionally and on behalf of any and all of their representatives individually (collectively "Protestants"). This Agreement is effective upon the latest date of the signatures below (the "Effective Date").

EPE is proposing to modify the existing Newman Generating Station, located at 4900 Stan Roberts Sr. Avenue in El Paso, El Paso County, Texas, by constructing a new Mitsubishi 501G series natural gas 230-Megawatt simple cycle combustion turbine fired by pipeline quality natural gas, referred to as Newman Unit 6, along with ancillary equipment ("Project"), which are more completely described in EPE's permit application ("Application"). To receive authorization for the Project, EPE filed air permit applications, including the Application, with the Texas Commission on Environmental Quality ("TCEQ"). Chaparral Community Coalition for Health and the Environment is an unincorporated neighborhood association based in Chaparral, New Mexico. Protestants have opposed the Application and TCEQ's issuance of the air permits applied for by EPE and were granted party status in State Office of Administrative Hearings ("SOAH") Docket No. 582-21-1740 (TCEQ Docket No. 2021-0314-AIR), which is pending at SOAH.

EPE and Protestants (collectively the "Parties" and individually a "Party") wish to terminate all disputes and administrative challenges related to the authorization, construction, and operation of the Project and avoid further and future litigation regarding the construction and operation of Newman Unit 6, generally, and challenges to TCEQ approval of EPE's air permit applications, including the Application.

With neither Party acknowledging fault, liability, or obligation, other than as described in this Agreement; and in consideration of the promises and covenants set forth in this Agreement; and for other good and valuable consideration, the sufficiency of which is hereby acknowledged, the Parties agree as follows:

1. INCORPORATION OF RECITALS

The above listed recitals and definitions are incorporated to this Agreement by reference.

2. OBLIGATIONS OF PROTESTANTS

2.1. TCEQ Administrative Process

Protestants will immediately file with SOAH a withdrawal of their request for a contested case hearing and objection to issuance of the permit. The Protestants will also join in a motion to remand the Application back to the TCEQ for consideration of the Application by the TCEQ Executive Director as unopposed. Protestants will not file a motion for rehearing or otherwise seek further administrative or judicial review of any TCEQ decision to approve the Application and to issue the draft permit prepared by the Executive Director in this matter ("Permit").

2.2. Future Opposition

As of the Effective Date, Protestants will not challenge the construction or permitting of the Project in any administrative or judicial forum, including by seeking judicial review of TCEQ authorization of the Project or funding any third-party litigation involving any claims settled, released, and waived by this Agreement.

3. OBLIGATIONS OF EL PASO ELECTRIC

3.1. Future Fossil Fuel Generation

With the exception of Newman Unit 6, EPE agrees that it will never construct any new fossil fuel generation units at Newman Generating Station. This restriction shall not apply to the conversions of existing generation units to operate on hydrogen fuel.

3.2. Construction Moratorium

With the exception of Newman Unit 6, EPE agrees to a four-year moratorium on EPE's construction of any additional EPE-owned fossil fuel-fired units to meet EPE's Native System Demand. The four-year moratorium period begins on the date the Permit for the Project is issued.

3.2.1. During the moratorium period, EPE is not prohibited from soliciting and obtaining regulatory approval for additional EPE-owned fossil fuel-fired units.

3.2.2. The moratorium does not include construction of any customer-dedicated resource, i.e. a unit or units dedicated solely for the benefit of a single customer or group of customers that is not a system resource.

3.2.3. The moratorium does not include construction related to any existing units.

3.2.4. The moratorium does not include installation or use of any authorized temporary generation responsive to any emergency or reliability conditions.

3.3. Abandonment of Existing Units

No later than the start of commercial operations date of Newman Unit 6, EPE will file abandonment applications for Newman Unit 1 or Newman Unit 2 and Rio Grande Generation Station Unit 7 with the New Mexico Public Regulation Commission and will use its best efforts in good faith to obtain approval thereof.

3.4. Emission Reductions

Following issuance of the Draft Permit, EPE will immediately seek an alteration of the applicable permits to reduce the allowable tons per year of nitrogen oxides ("NOx") and carbon dioxide ("CO2") emissions from Newman Unit 6 by 40% from the proposed permit. Specifically, EPE will agree to the following allowable tons per year from Newman Unit 6:

3.4.1. 790,000 tons per year of CO2.

3.4.2. 72 tons per year of NOx.

3.4.3. If TCEQ declines to incorporate the limitations in Section 3.4.1and 3.4.2 into the final permit for Newman Unit 6, EPE nevertheless commits to meeting those emission limitations at Newman Unit 6.

3.5. Purchase of VOC Emission Credits

If and when a regional volatile organic compound ("VOC") credit market arises following a final nonattainment designation for El Paso County by the U.S. Environmental Protection Agency ("EPA"), EPE will commit $500,000 to buy VOC emission offset credits to offset 110% of actual VOC emissions from Newman Unit 6.

3.5.1. If the EPA does not designate El Paso County as an ozone nonattainment area by the end of 2022 or a regional credit market fails to develop by the end of 2023, the $500,000 shall be redirected by July 31, 2024, to other emission reduction or energy efficiency projects that shall be jointly selected by the Chaparral Community Coalition and EPE. If the Chaparral Community Coalition and EPE are unable to agree on emission reduction or energy efficiency projects by July 31, 2024, the selection of projects shall be decided through the Dispute Resolution provision in Section 12 below. Sierra Club expressly will not have decision-making authority for how the funds will be spent but may have an advisory role.

3.6. Community Project Fund

Upon issuance of the Permit for Newman Unit 6, EPE will provide $400,000 to a charitable fund (preferably a 501(c)(3) non-profit organization) to be designated and administered by Chaparral Community Coalition as part of a community benefits agreement. The Chaparral Community Coalition will have authority to determine how the funds are spent but shall include pollution reduction or mitigation measures. Sierra Club expressly will not have decision-making authority for how the funds will be spent but may have an advisory role.

3.7. Information pertaining to Newman Unit 6

EPE will create and support a webpage for Newman Unit 6 posting quarterly emission reports filed with regulatory agencies.

3.8. Protestants' Attorney's Fees

Upon issuance of the permit for Newman Unit 6, EPE will provide $40,000 to Protestants for reasonable attorney and expert fees and costs.

4. MULTIPLE ORIGINALS

This Agreement may be executed in any number of identical counterparts, each of which for all purposes is deemed an original, and all of which constitute collectively one agreement. The Parties agree that original signatures are not necessary for this Agreement.

5. AUTHORITY

Each of the undersigned representatives of EPE and Protestants represent that they have the actual and express authority to execute this Agreement for the above-named entities and persons, including representatives, and that by their signature they are binding that Party, its assigns, directors, officers, trustees, employees, representatives, and attorneys to the terms of this Agreement. EPE and Protestants further represent that they will fulfill all of the terms and conditions contained in this Agreement.

6. BINDING ON SUCCESSORS AND ASSIGNS

EPE and Protestants each acknowledge that this Agreement is binding on each of their successors and assigns.

7. FORCE MAJEURE

7.1. No Party shall be liable for any delay or failure of performance under this Agreement if such delay or failure results from a Force Majeure Event. For purposes of this Agreement, a "Force Majeure Event" shall mean an event that has been or will be caused by circumstances beyond the control of the Party that delays compliance with any obligation of this Agreement or otherwise causes a violation of any obligation of this Agreement despite that Party's reasonable and prudent best efforts to fulfill such obligation. The requirement that the Party exercise "reasonable and prudent best efforts to fulfill such obligation" includes using reasonable and prudent best efforts to anticipate any potential Force Majeure Event and to address the effects of such event (i) as it is occurring and (ii) after it has occurred, such that the delay or violation and any adverse environmental effects of the delay or violation is minimized. "Force Majeure" does not include the party's financial inability to perform any obligation under this Agreement.

7.2. If any Party claims a Force Majeure Event, it shall give notice to the other Party within a reasonable time but, in any event, within 30 days after the date the Party-claimant knew or with due diligence should have known of the Event. If the Parties disagree regarding a claim of Force Majeure, the Parties shall attempt to resolve that dispute pursuant to Section 12 of this Agreement. In any such dispute, the Party seeking to invoke Force Majeure shall have the burdens of proof and persuasion to demonstrate that a Force Majeure Event occurred based on the standards set forth above.

7.3. Subject to the provisions of Sections 7.1 and 7.2 above, if a delay or violation is caused by a Force Majeure Event, such delay or violation shall not be considered a breach of this Agreement. The Parties by agreement or the Court by order may modify the obligations and extend the time periods under this Agreement to remedy breaches or delays caused by a Force Majeure Event.

8. NO ADMISSION OF LIABILITY

EPE and Protestants each acknowledge that this Agreement does not constitute an admission of liability by either Party or any recognition of the correctness of their respective positions.

9. NO PARTNERSHIP

This Agreement should not be construed as making EPE and Protestants partners or joint venturers.

10. ENTIRE AGREEMENT

This Agreement embodies and constitutes the entire understanding between EPE and Protestants with respect to the settlement contemplated in this Agreement. All prior contemporaneous agreements, understandings, representations, and statements, oral or written, are merged into this Agreement.

11. NOTICES

Any written notifications required under this Agreement shall be provided by (i) email or fax and (ii) certified mail, return receipt requested or nationally recognized overnight delivery service to the following:

For Sierra Club:
Joshua Smith
2101 Webster Street, Suite 1300
Oakland, CA 94612
Joshua.smith@sierraclub.org:

For Chaparral Community Coalition:
Ida Garcia
300-2 McCombs Road
Personal Mail Box 187

Chaparral, New Mexico 88081
ida88021@yahoo.com

For EPE:
General Counsel
El Paso Electric Company
P.O. Box 982
El Paso, TX 79960
(with copies to EPE Regulatory Affairs, Operations and Environmental Department)

Notices shall be effective upon receipt or refusal. Any Party may update its own notification address(es) and information by providing such information in writing to the other Party.

12. DISPUTE RESOLUTION

In the event that a dispute arises among the Parties related to the terms or enforcement of the provisions of this Agreement, each shall make a good faith effort to settle such dispute by negotiation. In the event the Parties are unable to settle the dispute by negotiation, both shall make a good faith effort to settle the dispute by mediation (with the assistance of a mutually agreed upon mediator) without resorting to litigation. This Agreement has been made under and shall be interpreted and enforced by Texas law, and any causes of action related to this Agreement shall be maintained in Texas courts.

13. MISCELLANEOUS

13.1. If any provision of this Agreement is held to be unenforceable for any reason, it shall be adjusted rather than voided in order to achieve the intent of the Parties to the extent possible. In any event, the invalidity or unenforceability of any provision of this Agreement shall not affect the validity or enforceability of the remainder of this Agreement.

13.2. It is expressly understood and agreed that this Agreement is solely for the benefit of the Parties, and nothing in this Agreement is intended or shall be construed to provide any rights or defenses to any other parties. This Agreement expressly does not create any rights in any entity or individual that is not a party to this agreement

13.3. Headings in this Agreement are provided for convenience only and are not a substantive part of this Agreement.

13.4. This Agreement shall not be modified, altered, or discharged except by a written agreement signed by authorized representatives of the Parties.

13.5. Protestants shall not be liable to EPE for money damages in the event of a breach of their obligations under Section 2, above. If EPE believes Protestants have breached their obligations under Section 2, EPE will provide prompt notice of breach and a reasonable amount of time to cure any breach. The sole remedy for any breach shall be injunctive relief directing Protestants to fulfill the obligations in Section 2.

14. ACKNOWLEDGMENT

EPE and Protestants, by and on behalf of itself and its representatives, acknowledge that they have had adequate opportunity to retain and consult with legal counsel of their choosing to advise them with regard to this Agreement. The Parties expressly warrant and represent to each other that they have reviewed and fully discussed this Agreement with counsel and have satisfied themselves that they fully understand the terms, conditions, contents, and effects of this Agreement and make this Agreement knowingly, voluntarily, and without threat of duress after such consultation.

[*SIGNATURES BEGIN ON NEXT PAGE*]

IN WITNESS WHEREOF, EPE and Protestants have entered into this Agreement, and this Agreement is executed by EPE and Protestants as of the Effective Date.

EL PASO ELECTRIC COMPANY,
A Texas corporation

By: ______________________

Title: SVP - Operations

Date: 8/16/21

Chaparral Community Coalition for Health and the Environment, an unincorporated neighborhood association

By: ______________________

Title: ______________________

Date: ______________________

SIERRA CLUB

By: ______________________

Title: ______________________

Date: ______________________

IN WITNESS WHEREOF, EPE and Protestants have entered into this Agreement, and this Agreement is executed by EPE and Protestants as of the Effective Date.

EL PASO ELECTRIC COMPANY,
A Texas corporation

By: ______________________________

Title: ____________________________

Date: ____________________________

Chaparral Community Coalition for Health and the Environment, an unincorporated neighborhood association
By: Olda Garcia

Title: Chairperson

Date: 08/14/21

SIERRA CLUB
By: ______________________________

Title: ____________________________

Date: ____________________________

IN WITNESS WHEREOF, EPE and Protestants have entered into this Agreement, and this Agreement is executed by EPE and Protestants as of the Effective Date.

EL PASO ELECTRIC COMPANY,
A Texas corporation

By: ______________________

Title: ______________________

Date: ______________________

Chaparral Community Coalition for Health and the Environment, an unincorporated neighborhood association

By: ______________________

Title: ______________________

Date: ______________________

SIERRA CLUB

By: ______________________

JOSHUA SMITH

Title: STAFF ATTORNEY

Date: 8/15/2021

The following files are not convertible:

Exhibit JP-R3.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.

Key Auction Takeaways: Auction Clearing Prices relative to key thresholds

	Zone 1 (MN, ND, Western WI)	Zone 2 (Eastern WI, Upper MI)	Zone 3 (IA)	Zone 4 (IL)	Zone 5 (MO)	Zone 6 (IN, KY)	Zone 7 (MI)	Zone 8 (AR)	Zone 9 (LA, MS, TX)
2014-2015 Auction Clearing Price (ACP)	$3.29	$16.75	$16.75	$16.75	$16.75	$16.75	$16.75	$16.44	$16.44
2015-2016 Auction Clearing Price (ACP)	**$3.48**	**$3.48**	**$3.48**	**$150.00**	**$3.48**	**$3.48**	**$3.48**	**$3.29**	**$3.29**
2015-2016 Reference Level	$155.79	$155.79	$155.79	$155.79	$155.79	$155.79	$155.79	$155.79	$155.79
2015-2016 Conduct Threshold	$180.43	$180.65	$180.14	$180.53	$181.00	$180.45	$180.59	$179.45	$179.61
2015-2016 Cost of New Entry (CONE)	$246.41	$248.63	$243.48	$247.40	$252.05	$246.60	$248.03	$236.55	$238.22

*All values in $/MW-day

Auction Clearing Prices

$/MW-day

	Zone 1	Zone 2	Zone 3	Zone 4	Zone 5	Zone 6	Zone 7	Zone 8	Zone 9	Zone 10
2014-2015 ACP*	$3.29	$16.75	$16.75	$16.75	$16.75	$16.75	$16.75	$16.44	$16.44	N/A
2015-2016 ACP*	$3.48	$3.48	$3.48	$150.00	$3.48	$3.48	$3.48	$3.29	$3.29	N/A
2016-2017 ACP*	**$19.72**	**$72.00**	**$72.00**	**$72.00**	**$72.00**	**$72.00**	**$72.00**	**$2.99**	**$2.99**	**$2.99**
Conduct Threshold	*$25.80*	*$26.06*	*$25.52*	*$25.93*	*$26.42*	*$25.85*	*$25.98*	*$24.76*	*$25.12*	*$24.60*
Cost of New Entry	*$258.00*	*$260.58*	*$255.15*	*$259.26*	*$264.19*	*$258.47*	*$259.81*	*$247.56*	*$251.21*	*$246.05*

- Conduct Threshold is 10% of Cost of New Entry (CONE) for each Zone
- Conduct Threshold is $0 for a Generation Resource with a Facility Specific Reference Level

* Auction Clearing Price

Auction Clearing Prices Since 2014-15 PRA

$/MW-day

	Zone 1	Zone 2	Zone 3	Zone 4	Zone 5	Zone 6	Zone 7	Zone 8	Zone 9	Zone 10
2014-2015 ACP*	$3.29	$16.75	$16.75	$16.75	$16.75	$16.75	$16.75	$16.44	$16.44	N/A
2015-2016 ACP*	$3.48	$3.48	$3.48	$150.00	$3.48	$3.48	$3.48	$3.29	$3.29	N/A
2016-2017 ACP*	$19.72	$72.00	$72.00	$72.00	$72.00	$72.00	$72.00	$2.99	$2.99	$2.99
2017-2018 ACP*	**$1.50**	**$1.50**	**$1.50**	**$1.50**	**$1.50**	**$1.50**	**$1.50**	**$1.50**	**$1.50**	**$1.50**
Conduct Threshold	*$25.83*	*$26.09*	*$25.53*	*$25.94*	*$26.45*	*$25.85*	*$26.00*	*$24.79*	*$25.14*	*$24.61*
Cost of New Entry	*$258.32*	*$260.90*	*$255.31*	*$259.42*	*$264.52*	*$258.49*	*$260.00*	*$247.94*	*$251.42*	*$246.13*

- Current Conduct Threshold is 10% of Cost of New Entry (CONE) for each Zone
- Current Conduct Threshold is $0 for a generator with a facility specific Reference Level

* Auction Clearing Price

Historical Auction Clearing Price Comparison

<table>
<tr><th>PY</th><th>Zone 1</th><th>Zone 2</th><th>Zone 3</th><th>Zone 4</th><th>Zone 5</th><th>Zone 6</th><th>Zone 7</th><th>Zone 8</th><th>Zone 9</th><th>Zone 10</th><th>ERZs</th></tr>
<tr><td>2014-2015</td><td>$3.29</td><td colspan="6">$16.75</td><td colspan="2">$16.44</td><td>N/A</td><td>N/A</td></tr>
<tr><td>2015-2016</td><td colspan="3">$3.48</td><td>$150.00</td><td colspan="3">$3.48</td><td colspan="2">$3.29</td><td>N/A</td><td>N/A</td></tr>
<tr><td>2016-2017</td><td>$19.72</td><td colspan="6">$72.00</td><td colspan="3">$2.99</td><td>N/A</td></tr>
<tr><td>2017-2018</td><td colspan="10">$1.50</td><td>N/A</td></tr>
<tr><td>2018-2019</td><td>$1.00</td><td colspan="9">$10.00</td><td>N/A</td></tr>
<tr><td>2019-2020</td><td colspan="6">$2.99</td><td>$24.30</td><td colspan="4">$2.99</td></tr>
</table>

Conduct Threshold	*24.24*	*23.88*	*23.95*	*24.22*	*24.65*	*24.05*	*24.34*	*23.23*	*22.37*	*23.12*	*24.65*
Cost of New Entry	*242.36*	*238.82*	*239.51*	*242.16*	*246.47*	*240.49*	*243.37*	*232.27*	*223.67*	*231.15*	*246.47*

- Auction Clearing Prices & are displayed as $/MW-day
- Conduct Threshold is 10% of Cost of New Entry (CONE)
- Conduct Threshold is $0 for a generator with a Facility Specific Reference Level

Auction Clearing Prices Since 2014-15 PRA

$/MW-day

<table>
<tr><th></th><th>Zone 1</th><th>Zone 2</th><th>Zone 3</th><th>Zone 4</th><th>Zone 5</th><th>Zone 6</th><th>Zone 7</th><th>Zone 8</th><th>Zone 9</th><th>Zone 10</th></tr>
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<tr><td>2016-2017 ACP*</td><td>$19.72</td><td colspan="6">$72.00</td><td colspan="3">$2.99</td></tr>
<tr><td>2017-2018 ACP*</td><td colspan="10">$1.50</td></tr>
<tr><td>2018-2019 ACP*</td><td>$1.00</td><td colspan="9">$10.00</td></tr>
<tr><td>Conduct Threshold</td><td>$24.76</td><td>$24.25</td><td>$24.35</td><td>$24.62</td><td>$25.07</td><td>$24.45</td><td>$24.86</td><td>$23.63</td><td>$22.81</td><td>$23.63</td></tr>
<tr><td>Cost of New Entry</td><td>$247.59</td><td>$242.47</td><td>$243.48</td><td>$246.22</td><td>$250.66</td><td>$244.52</td><td>$248.60</td><td>$236.30</td><td>$228.11</td><td>$236.30</td></tr>
</table>

- Conduct Threshold is 10% of Cost of New Entry (CONE) for each Zone
- Conduct Threshold is $0 for a generator with a facility specific Reference Level

MISO

* Auction Clearing Price

Historical Auction Clearing Price Comparison

<table>
<tr><th>PY</th><th>Zone 1</th><th>Zone 2</th><th>Zone 3</th><th>Zone 4</th><th>Zone 5</th><th>Zone 6</th><th>Zone 7</th><th>Zone 8</th><th>Zone 9</th><th>Zone 10</th><th>ERZs</th></tr>
<tr><td>2014-2015</td><td>$3.29</td><td colspan="6">$16.75</td><td colspan="2">$16.44</td><td>N/A</td><td>N/A</td></tr>
<tr><td>2015-2016</td><td colspan="3">$3.48</td><td>$150.00</td><td colspan="3">$3.48</td><td colspan="2">$3.29</td><td>N/A</td><td>N/A</td></tr>
<tr><td>2016-2017</td><td>$19.72</td><td colspan="6">$72.00</td><td colspan="3">$2.99</td><td>N/A</td></tr>
<tr><td>2017-2018</td><td colspan="10">$1.50</td><td>N/A</td></tr>
<tr><td>2018-2019</td><td>$1.00</td><td colspan="9">$10.00</td><td>N/A</td></tr>
<tr><td>2019-2020</td><td colspan="6">$2.99</td><td>$24.30</td><td colspan="4">$2.99</td></tr>
<tr><td>2020-2021</td><td colspan="6">$5.00</td><td>$257.53</td><td>$4.75</td><td>$6.88</td><td>$4.75</td><td>$4.89-$5.00</td></tr>
</table>

IMM Conduct Threshold	*25.61*	*25.17*	*25.02*	*25.46*	*26.08*	*25.49*	*25.75*	*24.56*	*23.66*	*24.50*	*26.08*
Cost of New Entry	*256.08*	*251.67*	*250.22*	*254.68*	*260.79*	*254.88*	*257.53*	*245.64*	*236.58*	*244.96*	*260.79*

- Auction Clearing Prices shown in $/MW-day
- Conduct Threshold is 10% of Cost of New Entry (CONE)

Historical Auction Clearing Price Comparison

<table>
<tr><th>PY</th><th>Zone 1</th><th>Zone 2</th><th>Zone 3</th><th>Zone 4</th><th>Zone 5</th><th>Zone 6</th><th>Zone 7</th><th>Zone 8</th><th>Zone 9</th><th>Zone 10</th><th>ERZs</th></tr>
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<tr><td>2021-2022</td><td colspan="7">$5.00</td><td colspan="3">$0.01</td><td>$2.78-$5.00</td></tr>
</table>

	Zone 1	Zone 2	Zone 3	Zone 4	Zone 5	Zone 6	Zone 7	Zone 8	Zone 9	Zone 10	ERZs
IMM Conduct Threshold	25.43	24.92	23.92	24.86	26.67	24.42	25.97	23.09	22.90	22.86	26.67
Cost of New Entry	254.27	249.15	239.21	248.55	266.68	244.16	259.73	230.93	229.04	228.55	266.68

- Auction Clearing Prices shown in $/MW-day
- Conduct Threshold is 10% of Cost of New Entry (CONE)

13.0 Cost of New Entry

The Cost of New Entry ("CONE") value shall be 85.61 $/kw-yr. The CONE value shall be reviewed on or before November 1st of each year by the Transmission Provider and any changes shall be filed with the Commission. The Transmission Provider shall post the Commission-approved CONE for the next Summer Season on the SPP website within ten (10) calendar days of Commission approval.

The Transmission Provider's calculation of the CONE for the SPP Balancing Authority Area shall be based on publicly available information (e.g., information provided by the Energy Information Administration) relevant to the estimated annual capital and fixed operating costs of a hypothetical natural gas-fired peaking facility. The Transmission Provider shall consider factors, including, but not limited to: (1) physical factors (such as, the type of generating resource that could reasonably be constructed to provide Firm Capacity in the SPP Balancing Authority Area, costs associated with locating the Resource within the SPP Balancing Authority Area); (2) financial factors (such as, the hypothetical debt/equity ratio for the Resource, the cost of capital, a reasonable return on equity, applicable taxes, interest, insurance); and (3) other costs (such as, costs related to permitting, environmental compliance, operating and maintenance expenses). In calculating the CONE value, the Transmission Provider shall not consider the anticipated net revenue from the sale of capacity, energy or Ancillary Services.

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**

DIRECT TESTIMONY

OF

CLARENCE L. JOHNSON

ON BEHALF OF

THE CITY OF EL PASO

OCTOBER 22, 2021

demand charge. The customer is required to interrupt load on 30 minutes notice. The incentive (in the form of a credit) provided to the interruptible customer should be valued based on the avoided cost of peak generation capacity, similar to an energy efficiency program. The size of the interruptible credit should not be higher than avoided generation capacity cost. If the credit exceeds avoided capacity cost, the interruptible program is not cost justified and could be treated as a discounted rate pursuant to Sec. 36.007 PURA. As discussed previously, EPE quantifies avoided generation capacity based on the levelized cost associated with Rio Grande 9, a combustion turbine peak unit on its system. The noticed interruptible rate is currently closed to new customers. However, the Company proposes to open the rate to new customers, up to a maximum of 28 MW of new interruptible load.

Q. WHAT IS EPE'S RECOMMENDATION WITH RESPECT TO THE INTERRUPTIBLE RATE?

A. Although Mr. Carrasco's testimony acknowledges that the interruptible credit exceeds avoided cost and that the credit should be moved toward incremental capacity cost, the proposed increase in Rate 38 base revenues is $326,000—or 7.8%, which is less than the proposed percentage increase for eight other classes. The Company achieves this result by applying a 45.5% discount to the cost-based interruptible credit based on the estimate of incremental generation capacity. The Company calls this discount a "rate moderation adjustment."[50]

[50] WP/Q-7(a), Sheet: "Rate 38 Int Credit."

Q. IS THE 45.5% DISCOUNT OF COST-BASED DEMAND CREDITS AN UNDERSTATEMENT OF THE TRUE DISCOUNT?

A. Yes. As I discussed in Sec. V, the Company's incremental generation capacity cost estimate exceeds the avoided capacity cost derived in the energy efficiency rule and the most recent EIA estimate of CT costs by 40% - 88%. This suggests that the discount of cost-based demand credits is 106% - 175% rather than 45%.[51] By relying on a "high" avoided capacity cost, the Company conceals the full extent of the discount applied to cost-based credits.

Q. PLEASE SHOW THE INTERRUPTIBLE DEMAND CHARGE PERCENTAGE WITH THE COMPANY'S PROPOSAL AND AT DIFFERENT MEASURES OF AVOIDED COST.

A. The comparison below displays the interruptible demand charge (transmission voltage) based on the Company's proposal, and at EPE's measure of avoided capacity cost. The comparison also shows the interruptible demand charge based on measures of avoided cost approximating the current EIA CT cost ($60) and the PUC energy efficiency program avoided cost ($80). The resulting percentage of firm demand charge illustrates the reduction to the standard demand rates.[52]

Interruptible Demand Charge

	Firm	Interruptible	% Firm
Proposed	18.28	4.14	23%
At Cost Per EPE	18.28	8.56	47%

[51] For EIA estimate: [($166 per kW-yr. / $60 per kW-yr.) – 1]. For EE rule avoided cost: [($166 per kW-yr. / $80 per kW-yr.) – 1].
[52] WP/Q-7 (a), sheets: "Rate 38 Int Credit" and "Rate 38 Demand Rate."

Incremental Generation Capacity Cost
Per U.S. EIA 2021 Outlook

	Per kW
EIA CT Capacity--2022 In Service Date	**$ 594.00**
Construction Cost El Paso Region	
(WECC-Southwest)	
Levelized Fixed Charge Rate	**7.39%**
Levelized Cost per kW	**$ 43.90**
Fixed O&M Expense Per EIA	**$7.04**
Sub Total	**$ 50.94**
Add Reserve Margin (15%)	**$ 58.58**
Monthly at Transmission Voltage	**$ 4.98**
Monthly at Primary Voltage	**$ 5.17**
Monthly at Transmission Voltage	**$ 5.27**

Sources:

U.S. Energy Information Administration "Assumptions to Annual Energy Outlook 2021"
February 2021, Tables 4 and 5.
WP/Q-7 (a)

El Paso Electric

300 Galisteo Street, Suite 206
Santa Fe, New Mexico 87501
(505) 982-7391

EMAILED

September 16, 2021

Ms. Melanie Sandoval
Records Bureau
New Mexico Public Regulation Commission
P.O. Box 1269
Santa Fe, NM 87504-1269

21-00242-UT

**Re: Compliance Filing Pursuant to IRP Rule, 17.7.3 NMAC
El Paso Electric Company's Integrated Resource Plan**

Dear Ms. Sandoval:

Attached for filing please find El Paso Electric Company's ("EPE") Integrated Resource Plan ("IRP") for the period 2021-2040. This compliance filing is made pursuant to Section 9 of the Commission's IRP Rule, 17.7.3 NMAC which requires that certain electric utilities file an IRP, along with an action plan, every three years.

Distribution of the IRP, along with a copy of this letter, is being conducted through the following actions:

- EPE has posted an electronic copy of its IRP on EPE's website at www.epelectric.com/company/regulatory/2020-2021-new-mexico-integrated-resource-plan-public-meetings.
- Copies are being served electronically to the NMPRC Chairman and Commissioners, General Counsel of the NMPRC, the New Mexico Attorney General and counsel of record and pro se parties in EPE's most recent general rate case, NMPRC Case No. 20-00104-UT, and all active participants in EPE's Public Advisory Group, including NMPRC Staff members who participated in the IRP Public Advisory Group.

Thank you for your assistance in this matter.

Very truly yours,

/s/Nancy B. Burns
Nancy B. Burns
Deputy-General Counsel
El Paso Electric Company

Enclosures
Service List

EL PASO ELECTRIC
2021 INTEGRATED RESOURCE PLAN

The Electric Company®
El Paso Electric

Executive Summary

This study by Energy and Environmental Economics, Inc. (E3) details analysis that E3 performed to support the El Paso Electric Company's (EPE or El Paso Electric) 2021 Integrated Resource Plan (IRP) filing. E3 utilized its modeling software in combination with E3-developed inputs and inputs provided by El Paso Electric to identify optimal long-term resource portfolios for the period through 2045. El Paso Electric utilized these portfolio results directly in its IRP filing.

El Paso Electric is an electric utility providing generation, transmission, and distribution service to customers in southern New Mexico and western Texas. Customers in New Mexico account for approximately 20% of its system load. E3 developed optimal long-term resource portfolios for the entire system that minimize cost while ensuring compliance with all New Mexico and Texas policy requirements and maintaining reliability for all customers.

There are several factors that drive El Paso electric's long-term resource needs. El Paso Electric has several thermal units that are scheduled to retire over the next two decades. In addition, El Paso Electric expects continued growth in load, which together with resource retirements, drives a need for new resources to ensure reliability for customers. Maintaining reliability has always been paramount for long-term resource planning, but its importance has been underlined by recent widespread outage events in other parts of Texas and in California.

Another factor driving long-term planning is the change in market conditions. Over the next two decades, El Paso Electric expects gas prices to rise and the cost of renewable and storage resources to fall. These trends impact the optimal mix of generating resources over time. In addition, El Paso Electric must add renewable and zero-carbon resources to comply with clean energy policies in New Mexico and Texas. Notably, the New Mexico Renewable Energy Act (REA), as amended since El Paso Electric's previous IRP, requires El Paso Electric to supply New Mexico customers with a growing share of renewable energy and to supply New Mexico customers with 100% zero-carbon energy by 2045.

El Paso Electric already has a less carbon intensive portfolio than most other utilities, given its reliance on energy from nuclear, natural gas, and renewable energy sources. E3 estimates that El Paso Electric's current energy supply for retail customers in New Mexico and Texas is made up of more than 60% zero-carbon energy. Between now and 2023, El Paso Electric will add 270 MW of additional solar resources and 50 MW of paired battery storage to its system. Given the factors highlighted above, El Paso Electric will continue adding more renewable resources, which will cause the share of zero-carbon energy on its system to grow over time.

In this study, E3 utilized robust modeling tools and industry best practices to quantify future system needs and develop optimal least-cost resource portfolios. E3 performed four analyses:

1. **Planning reserve margin (PRM)** – Quantification of the PRM that is required to maintain resource adequacy and ensure reliability for the system.
2. **Effective load carrying capability (ELCC)** – Quantification of the contribution of resources – both existing and new – toward the PRM requirement for ensuring reliability.

3. **Portfolio analysis** – Identification of long-term resource additions that minimize cost while ensuring reliability and satisfying New Mexico and Texas clean energy requirements.
4. **Sensitivity analysis** – Assessment of changes to the portfolio that would result from changes to key planning assumptions.

The results of these analyses are summarized below.

Planning Reserve Margin (PRM)

The use of a PRM requirement to determine resource adequacy needs is common among utilities and grid operators throughout the industry. Starting in 2025, El Paso Electric plans to meet a 2-day-in-10-year (0.2 loss of load expectation, or 0.2 LOLE) reliability standard, meaning that there can be up to two days per year with outages, on average. Starting in 2030, El Paso Electric plans to meet a 1-day-in-10-year (0.1 LOLE) reliability standard, meaning there can be up to one day per year with outages, on average. The 0.1 LOLE reliability standard is more common practice in the industry for long-term resource planning.

To quantify the PRM requirement needed to meet this standard, E3 utilized its RECAP model, a loss-of-load probability (LOLP) model that has been used to evaluate the resource adequacy of electric systems across North America, including in California, Nevada, the Pacific Northwest, Montana, the Upper Midwest, and Canada. RECAP simulates resource availability for the electric system with a specific set of generating resources and loads under a wide variety of weather conditions, incorporating weather-matched load and renewable profiles, time-sequential dispatch logic for energy storage, and stochastic forced outages of generation resources. By simulating the system under hundreds of years' worth of conditions with different combinations of these factors, RECAP provides a statistically robust estimation of the PRM required to meet a reliability standard. Table ES-1 shows the PRM results for the El Paso Electric system.

Table ES-1. Planning Reserve Margin Requirements

Metric	Units	2025	2030
Loss of Load Expectation (LOLE)	days/yr	0.2	0.1
Expected System Median Peak	MW	2,245	2,420
Planning Reserve Margin	%	10%	13%
Total Perfect Capacity Need	MW	2,470	2,735

The quantification of the PRM depends on the accounting framework that's used for counting contributions of resources toward the PRM. In this study, E3 utilized a perfect capacity (PCAP) accounting framework, meaning that all resources – including renewable, storage, demand response, and thermal resources – are counted toward the PRM based on their effective load carrying capability (ELCC).

Effective Load Carrying Capability (ELCC)

ELCC has been increasingly recognized by the industry as the preferred method for measuring resources' firm capacity contribution to system reliability. E3 used RECAP to quantify ELCCs by evaluating how much firm capacity a resource can displace to maintain the desired LOLE targets. By simulating the EPE system across a wide range of potential system conditions, RECAP captures the limitations of resources and quantifies their contribution towards resource adequacy. E3 utilized the ELCC results to measure each resource's contribution toward the PRM within the portfolio analysis.

Portfolio Analysis

After quantifying the PRM requirement and resource ELCCs, E3 performed resource portfolio optimization using its RESOLVE model. RESOLVE is an electricity system capacity expansion model that identifies economically optimal long-term resource and transmission investments subject to reliability, technical, and policy constraints. RESOLVE considers both the fixed and operational costs of different portfolios and is specifically designed to simulate power systems operating under high penetrations of renewable energy and energy storage resources.

The study considers several resource options for meeting future resource needs. The study includes a range of renewable resource options, including solar photovoltaic (at nine potential locations), wind (at three potential locations), geothermal (at two potential locations), and biomass. The study also includes the option to select transmission upgrades to deliver energy from remote renewable resources. In addition to renewable resources, the study considers storage, combustion turbine, and demand resource options to meet future needs. For five existing thermal units that are scheduled to retire in the near-term, the study considers the option to extend their lifetimes by five years.

One of the key modeling constraints is ensuring that El Paso Electric's future resource portfolio complies with clean energy requirements in New Mexico and Texas while ensuring fair cost allocation between the two jurisdictions. Compared to the Texas renewable energy requirement, the New Mexico REA is more stringent, requiring an increasing share of retail sales to be supplied by renewable sources and requiring 100% of retail sales to be supplied by zero-carbon energy sources by 2045. If there are incremental costs associated with satisfying the New Mexico REA, then those costs must be allocated to New Mexico.

E3's analysis includes four cases that use different approaches to model a portfolio that satisfies the REA requirements:

1. **Least-Cost (LC)** – This case does not impose any constraints on the resource portfolio beyond reliability requirements.
2. **Least-Cost + REA Resources (LC+REA)** – This case reoptimizes the portfolio of the Least-Cost case to add additional renewables and storage resources dedicated to serving New Mexico customers to satisfy New Mexico's REA requirements.
3. **Separate System Planning (SPP)** – This case models the New Mexico and Texas systems independently without allowing interactions between them.

In addition, E3 modeled another separate system planning case (SPP H2) in which hydrogen generation is available for selection as a zero-carbon firm resource on the system. More information on these cases can be found in Table ES-2.

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**

DIRECT TESTIMONY

AND

WORKPAPERS

OF

EVAN D. EVANS

ON BEHALF OF THE

OFFICE OF PUBLIC UTILITY COUNSEL

COST ALLOCATION / RATE DESIGN PHASE

October 22, 2021

e. Exclusion of Energy Sales to Interruptible Loads in E1ENERGY Allocator

Q. DISCUSS THE ISSUE SURROUNDING THE EXCLUSION OF ENERGY SALES TO INTERRUPTIBLE LOADS FROM THE E1ENERGY ALLOCATOR.

A. Mr. Hernandez stated in his direct testimony that "EPE witness Novela develops the E1ENERGY allocator using kWh at supply excluding non-firm (interruptible) kWh."[26] In addition, in response to the CEP RFI No. 9-28, which is provided as Attachment EDE-7 to this testimony, Mr. Hernandez explained his justification for excluding the interruptible kWh from the E1ENERGY allocator. Mr. Hernandez stated:

> "The E1ENERGY allocator is used to allocate energy-related generation operation and maintenance ("O&M") expenses in the cost of service. Since the results of these allocations in the cost of service are used to determine EPE's firm base rates, then non-firm kWh should not be included in allocating O&M production expenses. Therefore, just like non-interruptible customers, interruptible customers receive the same treatment by using only their firm kWh in determining the production O&M costs included in their firm base rates." [27]

Q. IS MR. HERNANDEZ'S JUSTIFICATION FOR EXCLUDING INTERRUPTIBLE kWh FROM E1ENERGY REASONABLE?

A. No, it is not. Mr. Hernandez's approach shifts the responsibility for non-fuel, energy-related generation O&M entirely onto firm customers and causes Residential Service and other firm customers to subsidize the interruptible sales. The non-fuel, energy-related generation O&M costs are associated with operating and maintaining EPE's generation

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[26] *Id.* at 14:1-2.

[27] El Paso Electric Company's Response to CEP's Ninth Request for Information, Question CEP 9-28.

resources that serve both firm and interruptible load. It is not appropriate to force firm customers to bear the entirety of these costs.

Q. WHAT IS YOUR RECOMMENDATION TO CORRECT THIS ISSUE?

A. I recommend that the energy charge for interruptible service be increased to reflect the portion of these generation O&M expenses and all other associated costs that would be allocated to the interruptible energy if they were treated as a separate class. In addition, the associated incremental interruptible revenue should be credited to firm customers and allocated based upon the E1ENERGY allocator.

An alternative approach would be to simply assign the interruptible energy to the customer classes under which the interruptible customers receive firm service. This alternative approach would protect customer classes that only have firm service customers from subsidizing the energy-related costs of interruptible loads. However, it would cause firm customers in those classes to bear a portion of the energy-related costs associated with the customers whose firm service is reflected in those classes, but also have interruptible loads.

f. Allocation of Secondary Lines and Transformers on NCP Demands

Q. PLEASE DESCRIBE THE ISSUE RELATED TO THE ALLOCATION OF SECONDARY LINES AND TRANSFORMERS.

A. EPE proposes to allocate the investment in secondary overhead and underground lines and secondary line transformers based on the annual NCP demands for each customer class.[28]

[28] Direct Testimony of Adrian Hernandez at 20:24-28.

This affects the portion of the following FERC Distribution Plant Accounts that provide service at secondary voltages:

- 364 – Poles, Towers and Fixtures;
- 365 - Overhead Conductor and Devices;
- 366 - Underground Conduit;
- 367 – Underground Conductors and Devices; and
- 368 Line Transformers.

Q. WHAT ARE NCP DEMANDS?

A. NCP represents the summation of the maximum loads of each customer within a rate class, independent of the class peak or system peak. As a result, the NCP is the sum of maximum demand of each customer within a class, without respect to when it occurs. An NCP demand allocator assumes that for each customer class, every customer's peak demand occurs at the exact same time, even though it did not occur. It is virtually impossible that all customers would ever peak at the same time for most customer classes that have more than a few customers.

Q. WHAT JUSTIFICATION DID EPE STATE FOR THEIR PROPOSAL?

A. In his filed testimony in this case, Mr. Hernandez's only statement supporting the use of the NCP demand allocation method for secondary lines and line transformers was, "This method allocates costs to serve customers based on their diversity at the more localized secondary distribution system." [29] However, Mr. Hernandez's statement is contradicted by the fact that an NCP demand allocator assumes that each customer's maximum demand

[29] *Id.* at 21:12 – 14.

responsibilities with respect to OPUC's technical analysis staff. In addition, my responsibilities included providing technical assistance on legislative matters.

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A. I have a B.S. in Political Science and a M.A. in Urban Studies from the University of Houston. My graduate degree is in an interdisciplinary program offered by the University of Houston's College of Social Science which incorporated substantial training in economics, including course work in the application of cost-benefit analysis to public policy. During my 25-year tenure at OPUC, I gained experience in virtually all phases of economic review required for the ratemaking process. I was chairman of the Economics and Finance Committee of the National Association of State Utility Consumer Advocates ("NASUCA") and served as a presenter for NASUCA's workshops and panels on cost allocation and rate design, Demand-Side Management ("DSM") incentives, market power and electric utility competition. Also, at various times, I have undergone training in specific subjects such as electric wholesale market design, cogeneration engineering and Electric Reliability Council of Texas ("ERCOT") operations. During my work over the last nine years as a consultant, I have prepared reports, comments, and testimony related to electricity issues for public interest, state agency, and local government organizations. I have testified as an expert witness in over 150 utility rate proceedings. A summary of my educational and professional background is attached as Attachment A.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. My testimony will address selected issues with respect to El Paso Electric Company's ("EPE" or "Company") requested rate design and class cost of service. The City will present other witnesses who address the appropriate revenue requirement level. To the extent my testimony refers to, or utilizes, EPE's proposed revenue requirements, the use of the Company's requested revenues should be considered illustrative in nature, since the City's case disputes the Company's proposed increase in revenues.

Q. PLEASE SUMMARIZE YOUR TESTIMONY RECOMMENDATIONS.

A. My findings and conclusions are summarized below.

- The Company's request to remove $1.2 million in revenues associated with interruptible non-compliance should be denied. This is not non-recurring to the extent that EPE has experienced similar non-compliance in recent years, resulting in similar revenue penalties. My recommendation is to allocate this revenue amount to all firm customer classes, because interruptible non-compliance damages other customers.

- The Company's proposed $1.3 million reduction in revenues to reflect "lost revenues" from the energy efficiency program should be rejected. EPE's adjustment is not known and measurable and is contrary to Commission precedent.

- The Company's load factor calculation for Average & Excess-4CP is reasonable.

- The Company does not provide an explanation for changing the class allocation of imputed capacity associated with solar purchase power contracts from the energy allocator in the previous rate case to D1-Demand allocator in this case. Given the characteristics of these contracts, the E1-energy allocator should continue to be applied. In the alternative, the D12-Demand allocator would be a reasonable option.

- The "general" components of A&G Accounts 920-923 and 930.2 should be allocated on the basis of net plant instead of the labor basis used by the Company. The Company's labor allocator produces a distorted result because salaries and wages for operating and maintaining the Palo Verde Nuclear Station are not included in the allocation. As a result, the labor allocation does not reflect the appropriate underlying costs of EPE's functions. The unusual results for EPE justify an exception to the labor allocation frequently applied to these overhead accounts.

- The Company allocated A&G Account 930.1 (General Advertising) on the basis of customers. This is a change from the Company's previous application of the labor allocator to this account. There is no evidence that the cost of general advertising is driven by the number of customers. I recommend the application of an O&M allocation factor (O&MXUNCOL) to this account, which is consistent with the NARUC cost allocation manual.

- As the Company documents in its testimony, the COVID pandemic resulted in a dramatic impact on 2020 demand and energy allocation factors used in its class cost of service (CCOS) study. The Company's responds to the aberrant demand and energy patterns by applying a capping/floor procedure to the class revenue increases. This response is inadequate to address the pandemic impact on the CCOS study.

- Given the extraordinary impact of the pandemic on the CCOS study, my recommendation is to adjust the demand and energy allocation factors to reflect historical class relationships for the three-year period, 2017-2019. These adjustments permit the CCOS study to be used as a tool to evaluate class limiters applied to the class revenue increases.

- My testimony presents adjusted CCOS results, for both the Company's requested revenue requirement and the revenue requirement recommended by CEP witnesses. Based on the CCOS results, my conclusion is that the Company's proposed 150% capping of the residential revenue increase is not adequate.

- If the Commission awards EPE a material revenue increase, my recommendation is to cap all firm customer classes' revenue at 140% of the total Texas retail percent increase. In addition, if total Texas retail revenues increase, my recommendation is to place a floor of "no increase" on classes which would otherwise receive a revenue reduction. Given the circumstances of this case, awarding some classes a revenue reduction at the same time that overall revenues are increasing is not reasonable. The revenue reductions compound the revenue increases which must be collected from other classes.

- If the Texas retail revenue reduction recommended by CEP witnesses is adopted, my recommendation is to moderate indicated class revenue increases with zero increase and allocate the remaining revenue decrease in proportion to classes' revenue reduction at cost of service.

- EPE overstates the value of incremental generation capacity. As a result, EPE's rate design outlook may place excessive emphasis on the avoided costs associated with demand reduction. Consequently, tempering peak rates in TOU and seasonal rates may be warranted. Furthermore, the Company's measurement of the avoided capacity costs used to value the interruptible tariff conceals the full magnitude of underpricing interruptible demand charges.

- Based on its own calculations, the Company continues to underprice interruptible demand charges. Despite overstated avoided cost, EPE's proposal can achieve its target interruptible credits only by applying a 45% "rate moderation discount" to the interruptible demand charge. Severe underpricing of interruptible rates encourages the

the labor allocator to A&G expenses directly related to payroll, such as pensions and benefits, employment taxes, and labor related injuries and damages.

Q. CAN YOU DEMONSTRATE THAT THE OMISSION OF PALO VERDE PAYROLL FROM THE LABOR ALLOCATOR DISTORTS THE RELATIVE IMPORTANCE OF PRODUCTION TO THE COMPANY'S COST STRUCTURE?

A. Yes. The labor allocator spreads indirect costs to the utility's functions (production, transmission, distribution, customer) in proportion to direct payroll within each function. Thus, the allocation of indirect cost to customer classes will follow the functional assignment. Customer classes are responsible for varying proportions of each function. All firm classes pay for production costs, but transmission voltage classes are not responsible for distribution costs, and the allocation of customer costs is highly tilted toward the residential and small general service classes with numerous customers. Allocating a lower proportion of indirect costs to production tends to favor large industrial customers because a larger part of their bundled rate is generation. In order to illustrate the impact of Palo Verde on the labor allocator, I compared an adjusted labor allocator (which includes Palo Verde salaries for EPE's share of the plant[31]) with the actual labor allocator used in the CCOS study. If Palo Verde salaries had been included in the labor allocation, 59**%** of general expense in Accounts 920 and 923 would have been allocated based on production. By comparison, the Company's method allocates **34%** of general expenses on the basis of production. Since 65% of

[31] EPE share of 2020 Palo Verde straight time wage and salary expense derived from EPE Response to CEP 9-4, Attachment 1. EPE's share of this payroll is invoiced as an expense, and therefore is not included in the CCOS study wage and salary distribution.

non-fuel revenue requirement is production,[32] the Company's labor allocator significantly understates the contribution of the production function to EPE's cost structure.

Q. WHAT ALLOCATOR DO YOU RECOMMEND FOR GENERAL EXPENSES IN ACCOUNTS 920 AND 923 WHICH THE COMPANY ALLOCATES ON LABOR?

A. My recommendation is to apply the net plant allocator instead of the general labor allocator.[33] I performed a comparison of internal allocation factors. The net plant allocator provides a more balanced representation of functional proportions than the labor allocator. The table below shows the functional ratios associated with the Company's CCOS labor allocator, an adjusted labor allocator (includes Palo Verde wages and salary), net plant allocator, allocation based on non-fuel O&M expense, and revenue requirements.[34] The Company's labor allocator produces anomalous results compared to the other methods. Although a labor allocator including Palo Verde salaries would be reasonable, it is difficult to incorporate a new internal allocator into the Company's CCOS model. The net plant allocator provides reasonably comparable

Indirect Allocator	Production	Transmission	Distribution	Customer
Labor	34%	21%	28%	17%
Labor-PVNGS included	59%	13%	17%	11%
Net Plant	54%	12%	32%	2%
O&M Expense	75%	8%	10%	7%
Revenue Req.	65%	11%	19%	5%

[32] EPE Response to Staff 8-01 Attachments 1 & 2; Schedule P-1.03.
[33] An internal allocator based on non-fuel O&M excluding A&G expense would also be reasonable.
[34] All of the data shown here exclude A&G expense and General Plant.

results relative to the remaining allocation methods and is generally consistent with Company's cost structure.

Q. IS NET PLANT REASONABLY RELATED TO THE ACTIVITIES OF PERSONNEL ENCOMPASSED IN ACCOUNT 920?

A. Yes. This account contains the salaries of corporate officers with responsibility for the full corporate entity, as well as finance, treasury and legal department professionals. Presumably the top management of the Company pays particular attention to capital commitments and investments, as well as debt obligations resulting from capital outlays. Moreover, plant in service forms the basis for utility earnings, which the officers of the corporation have a responsibility to protect. Furthermore, as shown above, plant in service is reasonably related to the Company's revenue requirements. The personnel involved in general management are concerned with all of the utility functions that comprise the utility's revenue requirements.

Q. HAVE YOU CHANGED THE ALLOCATION OF ACCOUNT 930, MISCELLANEOUS GENERAL EXPENSE?

A. Yes. $2.7 million of "Other Expenses" in Account 930.2, Miscellaneous General, is categorized as "General" and allocated on a labor basis by the Company. For this component of Account 930.2, I recommend changing the allocation from labor to net plant. The reason for this change is the same as stated for Accounts 920 and 923. The expenses in this account are not directly related to payroll, and the labor allocator does not spread the indirect expenses across functions in a balanced manner, because labor

Hernandez identified as peaking units generate a substantial amount of MWh during the non-summer months.

Q. WHAT IS YOUR RECOMMENDATION CONCERNING THIS ISSUE?

A. I recommend EPE's production plant not be divided into peaking and non-peaking plants for production demand cost allocation. I recommend that all of EPE's production plant be allocated among Texas retail customer classes based upon the 4CP-A&E production demand allocator.

d. Error in EPE's Production 12CP Allocator

Q. DID EPE MAKE THE SAME ERROR IN ITS PRODUCTION 12CP ALLOCATOR IN THE CUSTOMER CLASS COST STUDY AS IT DID IN THE JURISDICTIONAL COST STUDY?

A. Yes. DPROD12 does not reflect EPE's 12CP demands. Based on a review of the EPE Regulatory Case Working Model ("EPE Working Model") provided by EPE in their filing and Attachment 2 to EPE's response to the CEP RFI No. 4-6, it appears EPE inadvertently used information from a column entitled "12CP-A&E" instead of 12CP for the allocator DPROD12. In his testimony, Mr. Hernandez identified the DPROD12 allocator as a 12CP allocator.[25]

Q. WHAT IS YOUR RECOMMENDATION ON THIS ISSUE?

A. I recommend the DPROD12 allocator be corrected to reflect the 12CP allocation. The 12CP allocator by customer class is shown in Attachment EDE-6.

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[25] *Id.* at 23:29.

e. Exclusion of Energy Sales to Interruptible Loads in E1ENERGY Allocator

Q. DISCUSS THE ISSUE SURROUNDING THE EXCLUSION OF ENERGY SALES TO INTERRUPTIBLE LOADS FROM THE E1ENERGY ALLOCATOR.

A. Mr. Hernandez stated in his direct testimony that "EPE witness Novela develops the E1ENERGY allocator using kWh at supply excluding non-firm (interruptible) kWh."[26] In addition, in response to the CEP RFI No. 9-28, which is provided as Attachment EDE-7 to this testimony, Mr. Hernandez explained his justification for excluding the interruptible kWh from the E1ENERGY allocator. Mr. Hernandez stated:

> "The E1ENERGY allocator is used to allocate energy-related generation operation and maintenance ("O&M") expenses in the cost of service. Since the results of these allocations in the cost of service are used to determine EPE's firm base rates, then non-firm kWh should not be included in allocating O&M production expenses. Therefore, just like non-interruptible customers, interruptible customers receive the same treatment by using only their firm kWh in determining the production O&M costs included in their firm base rates." [27]

Q. IS MR. HERNANDEZ'S JUSTIFICATION FOR EXCLUDING INTERRUPTIBLE kWh FROM E1ENERGY REASONABLE?

A. No, it is not. Mr. Hernandez's approach shifts the responsibility for non-fuel, energy-related generation O&M entirely onto firm customers and causes Residential Service and other firm customers to subsidize the interruptible sales. The non-fuel, energy-related generation O&M costs are associated with operating and maintaining EPE's generation

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[26] *Id.* at 14:1-2.

[27] El Paso Electric Company's Response to CEP's Ninth Request for Information, Question CEP 9-28.

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**

Direct Testimony and Exhibits

of

JEFFRY POLLOCK

On Behalf of

Freeport-McMoRan, Inc.

October 22, 2021

J. POLLOCK
INCORPORATED

$$A_{LS} \approx P_{LS} \text{ x } [H \text{ x } F_{LD}^2 + (1\text{-}H) \text{ x } F_{LD}]$$

Where: A_{LS} = Average Losses
P_{LS} = Peak Losses
H = Hoebel Coefficient
F_{LD} = Load Factor

For example, assuming peak losses of 3%, a Hoebel Coefficient of 0.8, and a 70% load factor, average losses should be 1.6% (3% x [0.8 x 0.49 + 0.2 x 0.7]). Thus, based on this relationship, the average (*i.e.,* energy) losses are, by definition, always lower than the corresponding peak (*i.e.,* demand) losses.

Q WHAT DO YOU RECOMMEND?

A The Commission should reject EPE's energy loss factors for the substation and transmission voltage services. At a minimum, the energy loss factors for these services should not exceed 90% of the corresponding demand loss factors. This would approximate the relationships between the energy and demand loss factors for primary and secondary services. It would also be consistent with industry standard practice. This would result in the following revised energy loss factors.

Table 3
Revised Energy Loss Factors

Voltage	Energy Loss Factor
Secondary	7.850%
Primary	5.123%
Substation	2.842%
Transmission 69 kV	2.511%
Transmission 115 kV	2.171%

Q HAVE YOU REVISED EPE'S ENERGY ALLOCATION FACTORS TO REFLECT YOUR RECOMMENDED ENERGY LOSS FACTORS?

A Yes. **Exhibit JP-3** shows the derivation of EPE's Energy1 allocation factors using the revised energy loss factors shown in Table 3.

Q SHOULD THE REVISED ENERGY1 LOSS FACTOR BE USED TO ALLOCATE ALL COSTS THAT ARE CLASSIFIED TO ENERGY?

A Yes.

Q DOES EPE USE A SECOND ENERGY ALLOCATOR TO ALLOCATE CERTAIN COSTS?

A Yes. EPE also uses a second energy allocator (Energy2) to allocate fuel and purchased power expense and certain rate base items. As discussed later, Fuel Factor revenues and eligible fuel expenses should be removed from the CCOSS. The difference between the Energy1 and Energy2 allocators is the latter includes both firm and interruptible service.

Q SHOULD THE ENERGY2 ALLOCATOR BE USED?

A No. The CCOSS determines the firm cost to serve. The non-firm rates are not included in the CCOSS, which is appropriate. Thus, non-firm energy sales are irrelevant in determining the cost to serve firm loads. Accordingly, the Commission should reject EPE's Energy2 allocator.

Q WOULD REVISING THE ENERGY LOSS FACTORS ALSO AFFECT THE AED-4CP ALLOCATION FACTORS?

A Yes. **Exhibit JP-4** shows the derivation of the AED-4CP allocation factors using both the actual system 1CP load factor and the revised energy loss factors shown in Table 3.

Load Dispatching Expense

Q WHAT IS LOAD DISPATCHING EXPENSE?

A Load dispatching expense is incurred by EPE in its production and transmission functions. Production load dispatching expenses are booked to FERC Account No. 556 (System load control), which is defined as follows:

> This account shall include the cost of labor and expenses incurred in load dispatching activities for system control. Utilities having an interconnected electric system or operating under a central authority which controls the production and dispatching of electricity may apportion these costs to this account and transmission expense Accounts 561.1 through 561.4, and Account 581, Load Dispatching-Distribution.[15]

Transmission load dispatching expenses are booked in FERC Account No. 561 (load dispatch), which is defined as follows:

> **561.1 Load Dispatch—Reliability.**
>
> This account shall include the cost of labor, materials used and expenses incurred by a regional transmission service provider or other transmission provider to manage the reliability coordination function as specified by the North American Electric Reliability Council (NERC) and individual reliability organizations. These activities shall include performing current and next day reliability analysis. This account shall include the costs incurred to calculate load forecasts, and performing contingency analysis.
>
> **561.2 Load Dispatch—Monitor and Operate Transmission System.**
>
> This account shall include the costs of labor, materials used and expenses incurred by a regional transmission service provider or other transmission provider to monitor, assess and operate the power system and individual transmission facilities in real-time to maintain safe and reliable operation of the transmission system. This account shall also include the expense incurred to manage transmission facilities to maintain system reliability and to monitor the

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[15] 18 C.F.R. Chapter 1, Part 101 - Uniform System of Accounts.

small, the revision results in an allocation consistent with AED-4CP methods previously used by EPE, as well as the circumstances specific to EPE.

Q. DO YOU AGREE WITH EPE THAT THE AED-4CP FORMULA SHOULD UTILIZE 4 CP LOAD FACTOR?

A. Yes. When coincident demands are used in the AED formula, the load factor should be consistent with the formula's measure of coincident demands—in this case 4 CP. If the load factor doesn't match the measure of peak demand, some classes' allocation factors may fall outside the boundaries of average demand and 4 CP demand, which is not a reasonable result.

Q. DOES THE NARUC COST ALLOCATION MANUAL (CAM) PROVIDE GUIDANCE ON THE LOAD FACTOR APPLICABLE TO AED-4CP?

A. No. The NARUC CAM does not address AED-4CP as an acceptable method. The NARUC CAM identifies AED as a non-coincident demand methodology. In fact, the NARUC Cost Allocation Manual states that coincident peak demands should not be used in the AED method. Therefore, the CAM cannot provide meaningful guidance on the load factor component for AED-4CP.

Q. PLEASE SUMMARIZE YOUR POSITION.

A. The AED-4CP formula used to allocate EPE generation capacity should employ a 4 CP load factor, as proposed by the Company in this case.

(2) ALLOCATION OF IMPUTED SOLAR CAPACITY

Q. HAS EPE MADE ANY OTHER CHANGE TO THE ALLOCATION OF PRODUCTION CAPACITY?

A. Yes. The Company has changed the allocation of Account 555-Purchase Power (Non-Reconcilable) from an energy allocation in Docket No. 46831 to AED-4CP in this filing.[13] The Company's testimony does not discuss this change in allocation. The components of this account consist of imputed solar capacity charges.[14]

Q. WHAT IS A CAPACITY IMPUTATION?

A. Capacity imputation is a treatment of purchase power which converts part of the contract energy charges to capacity charges. For the Macho Springs and Newman solar contracts, the Company includes $1.69 million as capacity charges in Account 555.[15] The primary impact of this rate treatment is to reflect part of the contract costs as non-reconcilable.

Q. DO YOU AGREE WITH THE ALLOCATION CHANGE MADE FOR THESE RESOURCES?

A. No. Energy is a more reasonable allocation than AED-4CP for solar resources. An allocation that focuses on the 4 summer peak hours, like AED-4CP is not a reasonable representation of cost causation for solar generation. First, the maximum monthly output for these two solar contracts occurs outside the four summer months.[16] Moreover, the capacity value of the solar generation is diurnal, rather than seasonal, in nature. Second, the solar generation is not dispatchable, which means the resources must be backed up by other resources in the event that weather reduces the solar contribution during peak periods. Third, the primary benefit of solar generation is

[13] Schedule P-2 (Errata No. 3), line 64. [Compare to Schedule P-2, Docket No. 46831.]
[14] EPE Response to CEP Request No.14-12.
[15] Ibid.
[16] EPE Response to CEP 14-12, Attachment 1.

reduction in the system's fuel expense. If an electric utility purchases solar generation over other power sources available in the market, the principal reason is to avoid fuel expense and reduce volatility associated with gas prices. If a market-based capacity charge is paid, the rationale for such a charge is to gain access to the price stability offered by solar power.

Q. PLEASE SUMMARIZE YOUR RECOMMENDATION.

A. Because the Company provides no explanation for changing the energy allocation applied to non-reconcilable solar generation expense, my recommendation is to apply the energy allocator (E1) to the expense. In the alternative, a 12 CP allocator (D12) is also reasonable, given that the demand-related benefit of solar power is diurnal rather than seasonal in nature.

C. <u>Covid-19 Impact on External Allocation Factors</u>

Q. IS THE EPE CCOS STUDY AFFECTED BY ABNORMAL CLASS USAGE EFFECTS IN THIS CASE?

A. Yes. The Company's CCOS utilizes class demands and energy from the 2020 test year. Beginning in the second quarter of 2020, the COVID 19 pandemic imposed extraordinary impacts on particular customer classes' electricity usage. In addition to severe negative economic effects due to the pandemic, the health protocols caused a large number of residential customers to stay at home during the normal work week and led to closures of certain types of businesses. As a result, demand and energy allocation factors for the residential class are higher than normal, and the same allocation factors for major commercial, industrial, and city/county classes are lower planning, shareholder services, and the like. Account 923 consists of outside services which cannot be attributed to particular functions of the utility. These are common costs of the corporation which are only weakly associated with any particular class allocation factors.

Q. FOR PURPOSES OF THE CCOS STUDY, SHOULD UTILITIES ATTEMPT TO IDENTIFY A&G EXPENSES WHICH CAN BE ASSOCIATED WITH PARTICULAR FUNCTIONS?

A. Yes. The Commission's filing forms encourage utilities to assign such general costs to particular functions of the utility if it can be readily determined through investigation. EPE allocates some components on the basis of production, transmission, distribution, or customer functions. However, EPE classifies 91% of Accounts 920 and 923 as "General," to be allocated on an indirect allocator.

Q. HOW DOES EPE ALLOCATE THE GENERAL COSTS IN ACCOUNTS 920 AND 923 TO CUSTOMER CLASSES?

A. The Company allocates the general expense in proportion to labor costs within each functional category (allocator labeled Labor excluding A&G). [30] In this particular case, my recommendation is to modify the allocation basis for the unassignable general expenses in Account 920 and 923.

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[30] Note that each functional group (such as production, transmission, or distribution expense) includes the supervisors for the function's labor force within a separate supervisory account, rather than A&G expense. Thus, A920 management salaries are not directly involved in supervising the workers included in labor excluding A&G.

Q. WHAT IS THE PROPER CRITERION FOR SELECTING AN APPROPRIATE INDIRECT ALLOCATOR FOR GENERAL COSTS IN ACCOUNTS 920 AND 923?

A. Because none of the potential allocators are strongly related in a causal sense to these A&G accounts, the selection should focus on the extent to which the allocator spreads corporate overhead broadly and equitably across corporate functions. The costs that are allocated support the overall enterprise. A reasonable general allocator should not be tilted in a direction that is out of proportion to the overall composition of costs. In this case, the labor allocator does not produce balanced results.

Q. WHY DO YOU PROPOSE TO CHANGE THE USE OF A LABOR ALLOCATION FOR THIS ACCOUNT?

A. The use of a labor allocator for A&G Accounts 920 and 923 is not unusual. But the composition of EPE's labor allocator produces incongruent results, which justifies rejection of the allocator for general corporate salaries and outside services. Because Arizona Public Service operates the jointly owned Palo Verde Nuclear Generation Station, EPE's CCOS study does not include Palo Verde payroll within the labor allocation factors (except for a few EPE employees on-site). Although Palo Verde constitutes approximately 40% of non-fuel production expense, the plant's labor expense is not included in the labor allocator. As a result, the labor allocation will understate the magnitude of the production function relative to EPE's overall operations. For this reason, an exception to the typical practice of using a labor allocation for Accounts 920 and 923 is justified. However, I would continue to apply the labor allocator to A&G expenses directly related to payroll, such as pensions and benefits, employment taxes, and labor related injuries and damages.

Q. CAN YOU DEMONSTRATE THAT THE OMISSION OF PALO VERDE PAYROLL FROM THE LABOR ALLOCATOR DISTORTS THE RELATIVE IMPORTANCE OF PRODUCTION TO THE COMPANY'S COST STRUCTURE?

A. Yes. The labor allocator spreads indirect costs to the utility's functions (production, transmission, distribution, customer) in proportion to direct payroll within each function. Thus, the allocation of indirect cost to customer classes will follow the functional assignment. Customer classes are responsible for varying proportions of each function. All firm classes pay for production costs, but transmission voltage classes are not responsible for distribution costs, and the allocation of customer costs is highly tilted toward the residential and small general service classes with numerous customers. Allocating a lower proportion of indirect costs to production tends to favor large industrial customers because a larger part of their bundled rate is generation. In order to illustrate the impact of Palo Verde on the labor allocator, I compared an adjusted labor allocator (which includes Palo Verde salaries for EPE's share of the plant[31]) with the actual labor allocator used in the CCOS study. If Palo Verde salaries had been included in the labor allocation, 59**%** of general expense in Accounts 920 and 923 would have been allocated based on production. By comparison, the Company's method allocates **34%** of general expenses on the basis of production. Since 65% of

[31] EPE share of 2020 Palo Verde straight time wage and salary expense derived from EPE Response to CEP 9-4, Attachment 1. EPE's share of this payroll is invoiced as an expense, and therefore is not included in the CCOS study wage and salary distribution.

Further, as previously explained, the AED-4CP method already recognizes the different types of generating units. Specifically, average demand recognizes those units designed to operate year round, while excess demand recognizes the units designed to provide load following. This includes both peaking units and demand response.

Accordingly, there is no reason to use different allocation methods for peaking and non-peaking base rate costs.

Q WHAT DO YOU RECOMMEND?

A All production capital costs and related expenses should be allocated to customer classes using the AED-4CP method. This is consistent with past Commission practice, as previously discussed.

<u>Classification of Production O&M Expense</u>

Q IS EPE PROPOSING TO CHANGE CERTAIN ASPECTS OF THE CLASSIFICATION OF PRODUCTION O&M EXPENSE?

A Yes. EPE is proposing to reclassify a significant portion of its production O&M expense from demand to energy.[28] For example, expenses that were partially classified between demand and energy (FERC Account Nos. 512, 513 and 514) would be classified entirely to energy. Further, accounts that were classified entirely to demand (FERC Account Nos. 519, 520 and 523) would be classified entirely to energy.

[28] *See* Table 1 supra.

Q WHAT IS THE BASIS FOR RECLASSIFYING THESE EXPENSES FROM DEMAND TO ENERGY?

A Mr. Hernandez states that EPE generally follows the NARUC CAM to determine how production O&M expenses should be classified between demand and energy.[29]

Q DID EPE FOLLOW THE GUIDANCE PROVIDED IN THE NARUC CAM?

A No. According to the NARUC CAM, only a portion of the production O&M expenses in FERC Account Nos. 502, 505, 519, 520 and 523 would be considered energy related. Specifically, these expenses should be:

> …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.[30]

Q IS THIS THE ONLY METHOD OF CLASSIFYING PRODUCTION O&M EXPENSES DESCRIBED IN THE NARUC CAM?

A No. The NARUC CAM also recognizes another common method is to classify each account according to its predominant character.[31] In other words, if the majority of expenses are labor-related, then the entire account would be classified as demand-related. Conversely, if the majority of the expense is material-related, then the entire account would be classified as energy-related.

Q WHAT DO YOU RECOMMEND?

A I recommend that the labor-related expenses in FERC Account Nos. 502 and 505 be classified to demand. All of the expenses in FERC Account Nos. 519, 520, and 523

[29] Hernandez Direct at 14.

[30] NARUC CAM at 36, 38.

[31] *Id.* at 66.

should be classified to demand, consistent with EPE's past proposals, because the proportions of labor and materials expenses are not defined and EPE has provided no support for classifying the entirety of these accounts to energy.

Revised Class Cost-of-Service Study

Q HAVE YOU PREPARED A REVISED CLASS COST-OF-SERVICE STUDY?

A Yes. My revised CCOSS is presented in **Exhibit JP-5**. In this revised study:

- The load-factor weighting in the AED-4CP method was based on the actual system 1CP load factor.
- AED-4CP was applied to all production plant.
- The energy allocation factor and average demand component of AED-4CP were revised to reflect my recommended energy loss factors for the rate classes taking service at the substation and transmission voltages.
- All costs allocated by EPE using the Energy2 allocator were allocated using the Energy1 allocator.
- Production and transmission load dispatching expenses were allocated using the AED-4CP and 4CP methods, respectively, which are the same allocation methods used for the related production and transmission plant.
- Fuel revenues and eligible fuel expenses were removed.
- The labor-related portion of the production O&M expenses charged to Account Nos. 502, 505, were classified to demand, while the production O&M expenses charged to Account Nos. 519, 520, and 523 were classified entirely to demand.

Q SHOULD YOUR REVISED CLASS COST-OF-SERVICE STUDY BE USED TO DETERMINE THE SPREAD OF ANY BASE REVENUE CHANGE THAT THE COMMISSION MAY AUTHORIZE IN THIS PROCEEDING?

A Yes. This is discussed in the following section of my testimony.

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**

DIRECT TESTIMONY

AND

WORKPAPERS

OF

EVAN D. EVANS

ON BEHALF OF THE

OFFICE OF PUBLIC UTILITY COUNSEL

COST ALLOCATION / RATE DESIGN PHASE

October 22, 2021

classes.[34] Mr. Hernandez states, "Account No. 904 - Uncollectible Accounts expenses are assigned based on the firm base and fuel revenues of each rate class, except for those rate classes that are not subject to account write-offs such as governmental customers or Commercial and Industrial ("C&I") Large customers."[35] This is a change from the EPE's allocation of the Uncollectible Accounts Expense in Docket No. 46831, EPE's last base rate case. In that case, EPE only proposed to exclude governmental customers.[36]

Q. WHAT JUSTIFICATION DID MR. HERNANDEZ PROVIDE FOR USING THIS ALLOCATION METHOD?

A. Mr. Hernandez stated, "EPE's allocation of uncollectible expense takes guidance from the Company's accounts receivable aging schedule to estimate bad debts. EPE recently changed their policy to exclude C&I Large customers from the aging schedule. Therefore, EPE's allocation of uncollectible expense will exclude both Other Public Authority and C&I Large customers."[37]

Q. DO YOU AGREE WITH EPE'S PROPOSED METHOD FOR ALLOCATING UNCOLLECTIBLE ACCOUNTS EXPENSE?

A. No. These Uncollectible Accounts costs cannot be specifically associated with any group of paying customers. These are cost associated with customers who are no longer known to be served by EPE. Therefore, it is not appropriate to allocate the costs associated with customers who are no longer EPE customers specifically to the paying customers in the

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[34] Direct Testimony of Adrian Hernandez at 15:10 – 13.

[35] *Id.* at 24:28-31.

[36] *Id.* at 15:15 – 21.

[37] *Ibid.* at 15:15-21.

classes under which they were formerly served. These costs are no more the responsibility of the paying customers in their former rate classes than it is customers in any other rate classes. Therefore, these costs should be considered as system costs and be recovered from all customer classes in proportion to sales revenues.

Q. HAS THE COMMISSION ADDRESSED THE ALLOCATION OF UNCOLLECTIBLE ACCOUNTS EXPENSE IN OTHER RATE CASES?

A. Yes. The Commission specifically addressed this issue in SPS's 2015 rate case, Docket No. 43695. Finding of Facts 310 and 311 of the Commission's Order on Rehearing in Docket No. 43695 directly addressed this issue. Those Finding of Facts state:

> 310. SPS reasonably allocated Uncollectible Account expense in FERC Account 904 on the basis of present base rate sales by class.
>
> 311. Uncollectible expenses are caused by non-paying customers, and the current customers in a particular class are not the cause of uncollectible expense created by other members of that class.[38]

Q. WHAT IS YOUR RECOMMENDATION?

A. I recommend EPE's proposed change be rejected in favor of allocating the Uncollectible Accounts Expense to all Texas retail customer classes based on sales revenues, which is consistent with the Commission's clearly stated precedent. EPE has not provided any reasonable justification for its proposed change, and EPE cannot support their allocation of these costs to all rate classes, except Other Public Authority and C&I Large customer classes.

[38] *Application of Southwestern Public Service Company for Authority to Change Rates*, Docket No. 43695, Order on Rehearing at FOF Nos. 310 and 311 (Feb. 23, 2016).

V. REVENUE INCREASE DISTRIBUTION

Q. WHAT CONCERNS ARE YOU ADDRESSING RELATIVE TO REVENUE INCREASE DISTRIBUTION?

A. In this section, I encourage the Commission to incorporate moderation in the movement of customer classes to equal rates of return as base rate increases are assigned to customer classes. The test-year, calendar year 2020, was an unusual year. The pandemic significantly impacted EPE's loads and the usage characteristics of customer classes in diverse ways.

Q. WHAT IS EPE'S PROPOSAL FOR THE DISTRIBUTION OF THE REVENUE INCREASE AMONG CUSTOMER CLASSES?

A. EPE proposed to modify the cost-based revenue requirements for the Residential Service, Water Heating, Small General Service, General Service, and City/County rate groups[39]. EPE proposed to initially cap the allocated base revenue increase for the Residential and Water Heating classes at 1.5 times the system average increase of 7.38%, or 11.07%[40]. EPE also proposed to limit the base revenue reductions for the Small General Service, General Service, and the City/County rate groups to 50% of the cost-based reduction from EPE's class cost of service at equalized rates of return.[41] The remaining amount of the

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[39] Direct Testimony of James Schichtl at 38:30 – 39:4.

[40] Direct Testimony of Manny Carrasco at 14:12 – 19.

[41] *Id.* at 14:25 – 26.

DOCKET NO. ________

APPLICATION OF EL PASO ELECTRIC COMPANY TO CHANGE RATES	§ § §	PUBLIC UTILITY COMMISSION OF TEXAS

DIRECT TESTIMONY

OF

ADRIAN HERNANDEZ

FOR

EL PASO ELECTRIC COMPANY

JUNE 2021

EPE witness Novela develops the E1ENERGY allocator using kWh at supply excluding non-firm (interruptible) kWh. The E1FUEL and E2ENERGY allocators are also developed by EPE witness Novela using all kWh at supply (including non-firm).

Q. HOW ARE ENERGY-RELATED PRODUCTION O&M EXPENSES ALLOCATED TO EACH JURISDICTION?

A. As discussed above, non-fuel O&M expenses are allocated to each jurisdiction on E1ENERGY. Reconcilable fuel and purchased power expenses are all allocated using E1FUEL. Non-reconcilable fuel and purchased power expenses that are not demand-related (such as the imputed capacity discussed above) would be allocated using the E2ENERGY allocator.

Q. IS EPE ALLOCATING PRODUCTION O&M DIFFERENTLY IN THIS CASE COMPARED TO ITS PREVIOUS RATE CASE?

A. Yes, similar to production plant, demand related O&M expenses related to peaking generation units will be allocated using the 4CP allocator, D2PROD. In addition, EPE's assignment of demand and energy allocators for each account has been changed slightly compared to the previous rate case filing to more closely reflect the NARUC manual and to be consistent with allocation factors used in other jurisdictions.

Q. HOW ARE TRANSMISSION O&M EXPENSES ALLOCATED AMONG THE JURISDICTIONS?

A. Most transmission O&M expenses are allocated based on the 4CP method. The 4CP allocator is identified as D2TRAN. The only exception is for FERC Account 561 – Load Dispatching. Load dispatching costs are incurred year-round; therefore, these costs are allocated using a 12CP allocator, DTRAN12.

Q. HOW ARE DISTRIBUTION O&M EXPENSES JURISDICTIONALLY ALLOCATED?

A. Distribution O&M expenses are either: (1) directly assigned to the respective jurisdiction that the expenses were incurred for; or (2) allocated based on their respective plant investment in each jurisdiction; or (3) allocated on a dynamic allocator based on the costs contained in the other accounts of the operation or maintenance account grouping.

Q. HOW ARE CUSTOMER ACCOUNTS AND CUSTOMER SERVICE & INFORMATION O&M EXPENSES ALLOCATED TO EACH JURISDICTION?

A. Customer Accounts and Customer Service & Information O&M expenses that are directly assignable are determined and directly assigned to the applicable jurisdiction, and the remaining accounts are allocated using customer-based allocators or through use of a dynamic allocator based on the costs contained in the other accounts of the account grouping. The only exception is FERC Account 904 – Uncollectible Accounts which is allocated using the firm base and fuel revenues of all customer classes except Other Public Authority and Commercial and Industrial (C&I) Large in each jurisdiction (UNCOLL_REVS).

Q. IS THERE A DIFFERENCE IN EPE'S ALLOCATION OF UNCOLLECTIBLE EXPENSE IN THIS CASE COMPARED TO EPE'S PREVIOUS CASE?

A. Yes. EPE's allocation of uncollectible expense takes guidance from the Company's accounts receivable aging schedule to estimate bad debts. EPE recently changed their policy to exclude C&I Large customers from the aging schedule. Therefore, EPE's allocation of uncollectible expense will exclude both Other Public Authority and C&I Large customers.

Q. HOW ARE ADMINISTRATIVE AND GENERAL ("A&G") EXPENSES ALLOCATED AMONG THE JURISDICTIONS?

A. Most A&G expenses are allocated to a jurisdiction based on the LABOR allocation factor or another labor related allocation factor derived from the labor expenses contained in the accounts of the applicable functional account grouping. A&G expenses related to a specific function (e.g., production, transmission, distribution) are allocated based on the function's assigned allocator. If an expense can be identified as benefiting a specific jurisdiction, then that expense is directly assigned to that jurisdiction (such as Regulatory Commission fees recorded in FERC Account 928 – Regulatory Commission Expenses).

Q. HOW ARE THE DEPRECIATION AND AMORTIZATION EXPENSES JURISDICTIONALLY ALLOCATED?

A. EPE jurisdictionally allocates depreciation and amortization expenses by function consistent with the allocation of plant-in-service amounts.

The amortization expenses that are directly assignable to a jurisdiction were first determined and assigned. The remaining amortization expenses related to a specific function (e.g., production, transmission, distribution) are allocated based on the function's assigned allocator. Otherwise, they are allocated using the LABOR allocation factor.

Q. HOW ARE REGULATORY DEBITS AND CREDITS ALLOCATED TO EACH JURISDICTION?

A. Regulatory debits and credits are directly assigned to each jurisdiction as specifically mandated by each jurisdiction's utility commission. In addition, the amount related to EPE's COVID adjustment is allocated using the LABOR allocator. EPE witness Cynthia S. Prieto discusses the COVID adjustment in her testimony.

Q. HOW ARE INCOME TAXES ALLOCATED TO EACH JURISDICTION?

A. Federal and state income taxes are split into two categories, current and deferred. Deferred federal and state income tax expenses are assigned an allocator based upon the underlying basis of the deferred income tax in RMS. Deferred federal and state income taxes are mostly allocated using dynamic allocators like NETPLT, but various allocators are used depending on the Reg Account descriptions in RMS. Current federal and state income taxes are calculated in RMS based on the allocated results of rate base and operating expenses. EPE witness Prieto discusses the calculation of the Company's income taxes.

Q. HOW ARE TAXES OTHER THAN INCOME TAXES ALLOCATED TO EACH JURISDICTION?

A. Payroll and unemployment taxes are allocated to jurisdictions based on the LABOR allocation factor. Jurisdictional allocation of property taxes is consistent with how each

ELECTRIC UTILITY COST ALLOCATION MANUAL

NATIONAL ASSOCIATION OF REGULATORY UTILITY COMMISSIONERS

January, 1992

CHAPTER 7

CLASSIFICATION AND ALLOCATION OF CUSTOMER-RELATED COSTS

Customer-related costs (Accounts 901-917) include the costs of billing and collection, providing service information, and advertising and promotion of utility services. By their nature, it is difficult to determine the "cause" of these costs by any particular function of the utility's operation or by particular classes of their customers. An exception would be Account 904, Uncollectible Accounts. Many utilities monitor the uncollectible account levels by tariff schedule. Therefore, it may be appropriate to directly assign uncollectible accounts expense to specific customer classes.

I. FUNCTIONALIZATION

The usual approach in functionalizing customer accounts, customer service and the expense of information and sales is to assign these expenses to the distribution function and classify them as customer-related.

A less common approach is called the plant/labor method that functionalizes customer accounts, customer service, and sales expenses according to the previously determined functionalization of utility plant and labor costs. The amount of payroll costs included in generation-, transmission-, and distribution-related operation and maintenance expenses determine the labor component of this functionalization. Since the majority of a utility's labor costs tend to be in distribution, the plant/labor method will tend to emphasize the distribution functionalization of customer accounts, customer service, and sales expenses.

II. CLASSIFICATION AND ALLOCATION

When these expenses are functionalized by the plant/labor method, they will follow the previously determined classification and allocation of generation, transmission, and distribution facilities.

Q. PLEASE DESCRIBE YOUR APPROACH TO RATE MODERATION, GIVEN DIVERGENT REVENUE REQUIREMENT POSITIONS IN THIS CASE.

A. I will present class revenue distribution recommendations based on the Company's requested base revenue increase, as well as the lower revenue requirement (and total revenue reduction) recommended by CEP witnesses.

Q. IS THE COMPANY'S APPROACH TO CAPPING CLASS REVENUE INCREASES ADEQUATE?

A. No. The Company's principal component is based on limiting the residential revenue increase to 150% of the Texas retail percentage increase. This percentage is higher than the residential revenue increase resulting from the CCOS with my recommended adjustments. Therefore, the revenue increase limitation should be reduced below 150%. In addition, applying this revenue limiter to other customer classes facing high percentage increase would be more equitable. The final component of the Company's class limiter is applied to classes with an indicated revenue decrease and multiplies the size of the rate reduction by 50%. However, this limitation is not well supported. In particular, how does the Company know that a revenue reduction of any size would be indicated in the absence of the extraordinary COVID impacts during the test year? As shown previously, the CCOS studies in Docket No. 49831 and the current case are not consistent in identifying classes that require a revenue reduction.

Q. PLEASE DESCRIBE THE PROCEDURE YOU APPLIED FOR MITIGATING CLASS REVENUE INCREASES UNDER THE COMPANY'S PROPOSAL.

A. My example is based on the Company's requested firm base revenue increase, but, for comparability, does not include the decrease in interruptible credits recommended in my testimony. The revenue distribution reflects two rate moderation tools: (1) Customer class revenue increases are capped at 140% of the system average percentage, and (2) No class receives a base revenue reduction so long as the total retail firm base revenues increase. In my view, given the circumstances in this case, the most equitable approach precludes a revenue reduction for any class when the overall retail system faces a significant revenue increase. Selected revenue reductions compound the severity of revenue increases confronting most customers. The revenue distribution based on the Company's proposed revenue requirement is shown on Schedule CJ-5.

Q. HAVE YOU PREPARED A REVENUE DISTRIBUTION BASED ON THE SYSTEM REVENUE REDUCTION RECOMMENDED BY CEP WITNESSES?

A. Yes. The revenue distribution is shown on Schedule CJ-6. My method is informed by the principle that no firm class should receive an increase when total Texas retail revenues are materially reduced. The moderation of results for classes with indicated increases is also justified by the inherent reliability issues caused by the test year in this case. Schedule CJ-6 is based on capping class revenue increases at zero, and allocating the remaining revenue reduction to classes in proportion to the percentage of reduction indicated by the CCOS study.

V. <u>EPE'S INCREMENTAL GENERATION CAPACITY COST</u>

Q. WHAT IS INCREMENTAL GENERATION CAPACITY COST?

A. Conceptually, this incremental cost represents the fixed generation costs which would be incurred in order to meet future increases in demand or resolve projected deficiencies in generation reserves. These incremental costs may also be referred to as avoided generation capacity cost, a term which focuses on actions that can be undertaken to avoid incurring future generation capacity cost. The concept is a measurement of forward-looking generation costs. Frequently the cost of a gas-fired combustion turbine (CT) plant is used as a proxy for the cost of peak demand, because such generation units can be installed relatively quickly, and the operational characteristics of a CT unit are ideal for meeting short duration peak loads. EPE's incremental generation capacity cost is based on the cost of installing a CT unit.

Q. WHAT IS THE IMPORTANCE OF INCREMENTAL CAPACITY COST TO EPE'S RATE DESIGN?

A. According to Mr. Carrasco's testimony, the Company uses its incremental generation capacity costs to inform various components of its rate design. For interruptible service, the Company uses incremental capacity cost to evaluate the pricing of interruptible demand charge credits. For time of use (TOU) and electric vehicle (EV) rates, incremental capacity costs are used to develop prices during peak periods. And, at least in general terms, the costs may inform the design of peak and off-peak prices, such as seasonal rate differentials.

Q. DO YOU HAVE CONCERNS ABOUT THE INCREMENTAL GENERATION CAPACITY COSTS USED BY EPE FOR ITS RATE DESIGN ANALYSES?

A. Yes. In my opinion, EPE's incremental costs *overstate* the cost of avoiding or delaying future generation capacity costs. The effect is to overstate the benefit of peak demand reduction. EPE's develops its incremental generation capacity cost based the cost of

Likewise, any over-recovered amounts that result from the initial application of the revenue increase maximum and minimums in the revenue distribution should not cause classes that have been assigned the minimum percentage base rate increase to drop below the established minimum base revenue increase percentage.

Q. DO YOU AGREE WITH EPE'S ASSUMPTION THAT THE IMPACTS OF THE PANDEMIC ONLY AFFECTED A FEW CUSTOMER CLASSES?

A. No, I do not agree. In addition, Mr. Novela stated, "The COVID-19 pandemic resulted in a 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. This phenomena (sic) drove significant increased usage from residential customers and a significant reduction in usage from the commercial and city/county customers."[44] These significant changes in usage patterns and usage levels will have a comparable impact on demand and energy allocators, which will impact all customer classes.

Q. HAVE YOU COMPARED THE TEST-YEAR USAGE LEVELS FOR THE CUSTOMER CLASSES TO THE USAGE LEVELS FROM PREVIOUS YEARS?

A. Yes. Attachment EDE-13 provides a comparison of the actual usage per customer, by customer groups for 2020 to the usage per customer for those same groups during the most recent five years of 2015 through 2019. This comparison clearly shows that only the Residential Service and the Military Reservation Service classes experienced reduced kWh per customer during 2020 compared to the five-year average and compared to 2019. The Residential Service class experienced an 11.59% increase over the five-year average and

[44] Direct Testimony of George Novela at 10:7-13.

Military Reservation Service experienced a 4.82% increase over the five-year average. Although the information is not available, it would be expected that 4CP demands, 12CP and MCD demands would also be higher for those classes, particularly the Residential Service class. In contrast, the Total Texas Retail jurisdiction experienced a 2.35% decline from the five-year average.

Q. DID EPE ADJUST CUSTOMER CLASS USAGE LEVELS TO NORMALIZE FOR THE IMPACT OF THE PANDEMIC?

A. No. Mr. Novela stated in his testimony that EPE did not make any adjustments to its allocator methodology to account for any shifts in usage patterns.[45] Also, in response to OPUC RFI No. 1-4, Mr. Novela stated, "However, EPE did not make any adjustments to test-year sales to normalize the impact of the COVID-19 pandemic."[46]

Q. WHAT IS YOUR RECOMMENDATION CONCERNING THE BASE REVENUE INCREASE DISTRIBUTION AMONG CUSTOMER CLASSES?

A. I recommend the base revenue increase distribution among customer classes reflect moderation. The moderated increases for rate classes should include a firm maximum percentage increase and a firm minimum increase by rate class. Since EPE is requesting a significant base rate increase, I do not recommend that any firm service rate class be assigned a base rate decrease. I recommend the revenue decreases be developed so that no firm service rate class be assigned an increase that is more than 150% of the Texas retail

[45] *Id.* at 10:14-16.

[46] EPE's Response to OPUC's First Request for Information, Question OPUC 1-4.

average base revenue increase percentage and no firm service class be assigned an increase that is less than 50% of the Texas retail average base revenue increase percentage.

Q. DO YOU BELIEVE THIS MODERATION APPROACH IS CONSISTENT WITH HISTORIC PRECEDENT?

A. Yes. In the past, the Commission has approved similar revenue distribution gradualism approaches in several settled and litigated base rate cases for fully integrated electric utilities.[47]

VI. RATE DESIGN ISSUES

Q. WHAT RATE DESIGN ISSUES WILL YOU ADDRESS IN THIS SECTION?

A. In this section, I will focus on EPE's proposed rate design changes affecting:

- Schedule 01 – Residential Service, including Off-Peak Water Heating Service Rider; and,
- Schedule 02 – Small General Service, including Off-Peak Water Heating Service.

a. Schedule 01 – Residential Service

Q. WHAT ISSUES WILL YOU ADDRESS RELATIVE TO THE RESIDENTIAL SERVICE RATE?

A. I will address EPE's following proposals that impact the standard Residential Service Rate and the Off-Peak Water Heating Service rate:

[47] Docket No. 40443, Order on Rehearing, FOF Nos. 287-290 (March 6, 2014) and Docket No. 46449, Order on Rehearing, FOF No. 314 (March 19, 2018).

- set the monthly Customer Charge to collect all the customer-related costs by increasing the charge from $8.25 per month to $10.54 per month;[48]
- shorten the summer season from six months (May through October) to four months (June through September);[49]
- double the current price differential between summer and non-summer Energy Charges from $0.01 per kWh to $0.02 per kWh;[50]
- double the current the price differential between the first and second blocks of the summer Energy Charges from $0.005 per kWh to $0.01 per kWh;[51] and
- increase the monthly Customer Charge by 89% from $2.56 to the full cost of $4.84 per month.[52]

Q. WHAT CONCERNS DO YOU HAVE WITH EPE'S PROPOSED CHANGE TO THE RESIDENTIAL SERVICE CUSTOMER CHARGE?

A. I am concerned that EPE's proposed change is a 28% increase over the current monthly Customer Charge. That alone is a significant increase that will have a greater impact on Residential Service customers with low usage. EPE's proposed increase should also be considered in conjunction with the monthly AMS surcharge rate of $2.65 that EPE has proposed in Docket No. 52040, EPE's Application for Approval of Advanced Metering System (AMS) Deployment Plan, AMS Surcharge, and Non-Standard Metering Service Fees.[53] The combination of these two charges would be a $4.94 per month increase, or

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[48] Direct Testimony of Manny Carrasco at 33:29 – 31.

[49] *Id.* at 33:1 – 2.

[50] *Id.* at 34:26 – 35:9.

[51] *Id.* at 35:11 – 17.

[52] *Id.* at 40:18 – 23.

[53] Docket No. 52040, *Application of El Paso Electric Company for Approval of Advanced Metering System (AMS) Deployment Plan, AMS Surcharge, and Non-Standard Metering Service Fees*, Attachment 3, page 1.