A. Schedules P-1, P-2, and P-3 present the assignment of cost of service to the Texas rate classes.

Q117. WHAT SCHEDULE SUMMARIZES THE OVERALL RESULTS OF DEMAND, ENERGY, AND CUSTOMER COMPONENTS STUDY FOR EACH RATE CLASS?

A. Schedule P-6 summarizes the results of the DEC Study by rate class and calculates the DEC components on a cost-per-unit basis.

Q118. PLEASE SUMMARIZE THE OVERALL RESULTS OF THE PROPOSED TEXAS CLASS COST-OF-SERVICE STUDY.

A. Table 5 below lists the results of the non-fuel cost assignment to each proposed rate class from the CCOS (not including non-firm revenues). The values shown are at equalized rate of return (full cost of service). The proposed allocation of revenue requirements and rate design is discussed and presented in the testimony of EPE witness Carrasco.

Table 5

Rate	Description	Base Revenue Deficiency @ Equalized Rate of Return*	Percent Increase Required
01	Residential Service	$79,328,391	25.09%
02	Small General Service	1,865,094	3.73%
07	Outdoor Recreational Lighting	12,953	1.47%
08	Government Street Lighting	(798,657)	-18.41%
09	Traffic Signals	(1,892)	-1.82%
11	Municipal Pumping	102,749	1.00%
15	Electrolytic Refining Service	453,378	22.47%
22	Irrigation Service	1,040	0.26%
24	General Service	(4,256,811)	-3.05%
25	Large Power Service	4,771,246	11.77%
26	Petroleum Refinery Service	859,417	5.21%
28	Area Lighting Service	549,099	19.45%
30	Electric Furnace Rate	437,397	32.23%
31	Military Reservation Service	1,372,249	9.21%
34	Cotton Gin Service	(2,593)	-1.83%
41	City and County Service	933,004	3.95%
WH	Water Heating Service	39,650	7.91%
Total*		$85,665,713	13.73%

*The base revenue deficiency amounts above do not include non-firm revenues.

VIII. Baseline for Distribution Cost Recovery Factor

Q119. WHAT IS THE DISTRIBUTION COST RECOVERY FACTOR?

A. A distribution cost recovery factor ("DCRF") is a rate mechanism under section 36.210 of the Public Utility Regulatory Act ("PURA") that allows an electric utility to periodically adjust its rates for changes in certain distribution costs. The Commission has adopted 16 Texas Administrative Code ("TAC") § 25.243 (the "DCRF Rule") to implement PURA Section 36.210, which allows a utility not offering customer choice such as EPE to file a DCRF application.

Q120. HAS EPE IMPLEMENTED A DCRF SINCE ITS LAST BASE RATE PROCEEDING?

A. Yes. A baseline was approved in EPE's last base rate case, Docket No. 52195, and a DCRF was approved in Docket 56425[2]. EPE witness Rene Gonzalez discusses the inclusion of DCRF revenues in base rates in his testimony.

Q121. WHAT IS EPE REQUESTING IN THIS CASE RELATED TO A DCRF?

A. EPE is requesting that the Commission establish a new baseline revenue requirement amount for EPE's distribution function, as defined by the DCRF Rule.

Q122. WHAT FORMULA DOES 16 TAC § 25.243 PRESCRIBE FOR SETTING THE DCRF?

A. 16 TAC § 25.243 prescribes the following formula:

$$= [((DIC_{C} - DICR_{C}) * ROR_{AT}) + (DEPR_{C} - DEPR_{RC}) + (FIT_{C} - FIT_{RC}) + (OT_{C} - OT_{RC}) - \Sigma(DISTREV_{RC\text{-}CLASS} * \%GROWTH_{CLASS})] * ALLOC_{CLASS} / BD_{C\text{-}CLASS}$$

Where:

DIC_C = Current Net Distribution Invested Capital.

DIC_{RC} = Net Distribution Invested Capital from the last comprehensive base-rate proceeding.

ROR_{AT} = After-Tax Rate of Return

$DEPR_C$ = Current Depreciation Expense

$DEPR_{RC}$ = Depreciation Expense

[2]Application of El Paso Electric Company to Amend its Distribution Cost Recovery Factor, Docket No. 56425, Order (June 13, 2024).

FIT_C = Current Federal Income Tax

FIT_{RC} = Federal Income Tax

OT_C = Current Other Taxes (taxes other than income taxes and taxes associated with the return on rate base), as related to DIC_C, calculated using current tax rates and the methodology, and not including municipal franchise fees.

OT_{RC} = Other Taxes, as related to DIC_{RC} and not including municipal franchise fees.

$DISTREV_{RC\text{-}CLASS}$ (Distribution Revenues by rate class based on Net Distribution Invested Capital from the last comprehensive base-rate proceeding) = ($DIC_{RC\text{-}CLASS}$ * ROR_{AT}) + $DEPR_{RC\text{-}CLASS}$ + $FIT_{RC\text{-}CLASS}$ + $OT_{RC\text{-}CLASS}$.

%GROWTHCLASS (Growth in Billing Determinants by Class)

$DIC_{RC\text{-}CLASS}$ = Net Distribution Invested Capital allocated to the rate class from the last comprehensive base-rate proceeding.

Q123. HOW IS DISTRIBUTION INVESTED CAPITAL ("DIC") DEFINED IN 16 TAC § 25.243?

A. 16 TAC § 25.243(b)(3) defines distribution invested capital as

> parts of the electric utility's invested capital, as described in PURA § 36.053, that are categorized as distribution plant, distribution-related intangible plant, and distribution-related communication equipment and networks properly recorded in Federal Energy Regulatory Commission (FERC) Uniform System of Accounts 303, 352, 353, 360 through 374, 391 and 397. Distribution invested capital includes only costs: for plant that has been placed into service; that comply with PURA, including § 36.053 and § 36.058; and that are prudent, reasonable, and necessary.

Q124. HOW DID YOU CALCULATE THE BASELINE DISTRIBUTION REVENUE REQUIREMENT?

A. The baseline distribution revenue requirement is calculated as defined in the DCRF Rule at 16 TAC § 25.243(d)(1) for DISTREV. It states that Distribution Revenue by Rate Class on net distribution capital from the last comprehensive base-rate proceeding is the product of Distribution Invested Capital (DIC_{RC}) and after-tax Rate of Return (ROR) plus current depreciation (DEP_{RC}), current Federal Income Tax ($FIT_{RC\text{-}CLASS}$), and Other Current Taxes ($OT_{RC\text{-}CLASS}$). Accordingly, Net Distribution Invested Capital is the sum (Σ) for all rate classes as expressed by the full DCRF formula above. Also, 16 TAC

§ 25.243(d)(1) is a description of the DCRF formula assuming that a baseline for the cost recovery factor has already been established. However, the data utilized is from the current case, extracted to establish the baseline within this proceeding.

Q125. PLEASE DESCRIBE THE CALCULATION OF THE RETURN ON DIC IN MORE DETAIL.

A. The return component is calculated from net distribution invested capital multiplied by the after-tax rate of return. 16 TAC § 25.243(d)(2) defines the after-tax rate of return as "the rate of return approved by the commission in the electric utility's last comprehensive base-rate proceeding if the final order (which may be an order on rehearing) approving the rate of return was filed less than three years before the application for a DCRF was filed." As indicated in the rule, only the FERC accounts delineated in section 16 TAC § 25.243(b)(3) of the rule are included in the equation. The balance of these accounts is classified as DIC_{RC} shown in line 1 of Exhibit AH-4 and then multiplied by the rate of return to produce the required return on Distribution Invested Capital. No transmission costs are included in this calculation.

Q126. HOW ARE THE DEPRECIATION, INCOME TAX, AND PROPERTY TAX BASELINE COMPONENTS OF THE DISTRIBUTION REVENUE REQUIREMENT DETERMINED?

A. 16 TAC § 25.243(d)(1) defines the depreciation, federal income tax, and other tax baseline components as values from the last comprehensive base-rate proceeding. Depreciation expense is listed on line 3 of Exhibit AH-4. Federal Income Taxes ($DFIT_{RC}$) are expressed on line 4 and Other Taxes (DOT_{RC}) on line 5 of Exhibit AH-4.

Q127. WHAT RATE OF RETURN DID YOU USE?

A. The Company requested WACC of 8.363% is the rate of return used to calculate the return on Distribution Invested Capital. See line 2 of Exhibit AH-4.

Q128. HOW DID YOU CALCULATE THE DCRF BASELINE VALUES INCLUDED IN EXHIBIT AH-4?

A. The Texas jurisdictional values included in the DCRF baseline are taken from EPE's cost-of-service model where I utilized the results of the FCOS, JCOS, and CCOS to calculate the DCRF baselines.

Q129. 16 TAC § 25.243 REQUIRES A CALCULATION OF DISTRIBUTION REVENUES BY RATE CLASS FROM THE LAST COMPREHENSIVE BASE-RATE PROCEEDING. HAVE YOU MADE THAT CALCULATION?

A. Yes. The calculations are from this proceeding for the purposes of establishing a baseline. Please see line 6 of Exhibit AH-4.

Q130. 16 TAC § 25.243(d)(1) REQUIRES A CALCULATION OF DISTRIBUTION RATE CLASS ALLOCATORS FROM THE LAST COMPREHENSIVE BASE RATE PROCEEDING. HAVE YOU MADE THAT CALCULATION?

A. Yes. These calculations are produced to establish a baseline for this rate case proceeding. Please see line 7 of Exhibit AH-4.

Q131. DOES EPE INTEND TO FILE A DCRF RATE RIDER IN THIS PROCEEDING?

A. No. EPE seeks approval of a revised DCRF baseline in this proceeding allowing for future cost recovery of "prudent, reasonable, and necessary" distribution invested capital as set forth by PURA Section 36.053 and pursuant to 16 TAC § 25.243 by calculating the distribution revenue requirement and the associated rates by customer rate class. Establishing a new baseline in this case will allow EPE to evaluate whether a DCRF proceeding in the future is warranted.

IX. Baseline for Transmission Cost Recovery Factor

Q132. WHAT IS THE TRANSMISSION COST RECOVERY FACTOR?

A. A Transmission Cost Recovery Factor ("TCRF") is a rate mechanism provided for by the PUCT under PURA Section 36.209 that allows an electric utility to periodically adjust its rates for changes in certain transmission costs via a tariff. PURA Section 36.209 describes the purpose of the TCRF as allowing a utility to:

> recover its reasonable and necessary costs for transmission infrastructure

> improvement and changes in wholesale transmission charges to the electric utility under a tariff approved by the federal regulatory authority to the extent that the costs or charges have not otherwise been recovered and are incurred after December 31, 2005.

The Commission adopted 16 TAC § 25.239 (the "TCRF Rule") to implement this factor.

Q133. HAS EPE IMPLEMENTED A TCRF?

A. No. EPE currently does not have a TCRF.

Q134. WHAT IS EPE REQUESTING IN THIS CASE RELATED TO A TCRF?

A. EPE is requesting that the Commission establish a new baseline revenue requirement amount for EPE's transmission function as defined by the TCRF Rule.

Q135. WHAT FORMULA DOES 16 TAC § 25.239 PRESCRIBE FOR SETTING THE TCRF?

A. 16 TAC § 25.239 prescribes the following formula:

$$TCRF = \frac{RR * ClassALLOC}{BD}$$

Where:

TCRF = transmission cost recovery factor in dollars per unit, for billing each customer class.

RR = transmission cost recovery factor revenue requirement (see formula in response to next question below).

ClassALLOC = the customer class allocation factor used to allocate the transmission revenue requirement in the utility's most recent base rate case.

BD = each customer class's annual billing determinant (kilowatt-hour, kilowatt, or kilovolt-ampere) for the previous calendar year.

Q136. WHAT PART OF THIS FORMULA IS EPE PROVIDING IN THIS PROCEEDING?

A. EPE is providing transmission cost recovery factor revenue requirement ("RR") as required by 16 TAC § 25.239(e) using the following equation:

$$RR = [revreqt + ATC]*ALLOC$$

Where:

Revreqt = the sum of the return on transmission invested costs ("TIC"), net of accumulated depreciation and associated accumulated deferred income taxes, plus investment-related expenses such as income taxes, other associated taxes, depreciation, and transmission–related miscellaneous revenue credits, but not including operation and maintenance expenses or administrative expenses. The return on TIC shall be calculated by multiplying the TIC by the utility's weighted-average cost of capital ("WACC") as established for the utility in a final commission order in a base rate case,

ATC = Approved Transmission Charges

ALLOC = the utility's Texas retail allocation of transmission revenue requirements

Q137. PLEASE EXPLAIN THE "REVREQT" COMPONENT OF THE REVENUE REQUIREMENT FORMULA.

A. This component of the formula is broken down into the following sections in Exhibit AH-5:

- Return on TIC (line 3)
- Depreciation Expense (line 4)
- Income Taxes (line 5)
- Other Taxes (line 6)
- Revenue Credits (line 7)

Further details on this calculation are discussed below.

Q138. WHAT ARE THE "APPROVED TRANSMISSION CHARGES" OR "ATC" IN THE FORMULA?

A. ATC are wholesale transmission charges allocated to Texas customers that have been approved by the FERC and that the Company is not recovering through other retail or wholesale rates. These transmission charges are the cost of purchasing transmission from other utilities in order to bring EPE's remote generation and purchased power to its retail customers including its Texas customers. They are charged to FERC Account 565, Transmission of Electricity by Others.

Q139. HOW IS THE "ALLOC" ELEMENT OF EPE'S REVENUE REQUIREMENT

CALCULATION DETERMINED?

A. Texas retail allocation of transmission revenue requirements is calculated from the data taken from EPE's cost-of-service model where I utilized the results of the FCOS, JCOS, and CCOS to calculate the TCRF baselines. The resulting allocation by rate class is determined by the revenue requirement for each rate class as a percentage of the total Texas revenue requirement. See line 8 of Exhibit AH-5.

Q140. HOW DOES THE TCRF RULE DEFINE TRANSMISSION INVESTED COSTS?

A. 16 TAC § 25.239(b)(2) defines "transmission invested costs" ("TIC") as the "net change in the electric utility's transmission investment costs including additions, upgrades, and retirements as booked in FERC Accounts 350-359, and accumulated depreciation."

Q141. WHAT IS THE WACC BEING USED TO CALCULATE THE RETURN ON TIC?

A. The Company's requested WACC of 8.363% is used to calculate return on TIC as shown on line 2 of Exhibit AH-5.

Q142. PLEASE DESCRIBE THE CALCULATION OF EPE'S TRANSMISSION INVESTMENT-RELATED EXPENSES IN MORE DETAIL.

A. As indicated in the TCRF Rule, these include: "investment-related expenses such as income taxes, other associated taxes, depreciation, and transmission–related miscellaneous revenue credits, but [do] not include [e] operation and maintenance expenses or administrative expenses". Depreciation expense for transmission plant is shown on line 4 and other taxes are shown on line 6 of Exhibit AH-5.

Q143. WHAT ARE THE RESULTING INCOME TAXES AND OTHER TAXES?

A. Income Taxes (TFIT) are shown in line 5 and Other Taxes (TOT) are shown in line 6 of Exhibit AH-6.

Q144. WHAT ARE THE "TRANSMISSION-RELATED MISCELLANEOUS REVENUE CREDITS" REFERRED TO IN 16 TAC § 25.239(e)?

A. Transmission–related miscellaneous revenue credits are revenues EPE received from the sale of wholesale transmission service under its Open Access Transmission Tariff approved by the FERC. These transmission revenues reduce the revenue requirement that would otherwise be collected from retail customers. This Texas jurisdictional allocation of transmission revenues is seen on line 7 of Exhibit AH-5.

Q145. WHAT IS THE "REVREQT" COMPONENT AMOUNT OF THE REVENUE REQUIREMENT FORMULA?

A. After having calculated the baseline costs and revenue credits discussed above, the revreqt amount of $12,388,584 is calculated on line 8 of Exhibit AH-5.

Q146. DOES EPE HAVE ANY VARIABLE-APPROVED TRANSMISSION CHARGES ("ATC") TO INCLUDE IN THE BASELINE CALCULATION?

A. Yes. EPE purchases transmission wheeling from other utilities to deliver power from PVGS and for power it purchases to serve retail customers. Transmission wheeling expense charged to FERC Account 565, Transmission of Electricity by Others, is allocated to Texas and reflected as ATC on line 9 of Exhibit AH-5.

Q147. HOW IS THE TCRF REVENUE REQUIREMENT (RR) CALCULATED?

A. As previously stated, the RR is calculated as:

RR = [revreqt + ATC]*ALLOC

The numbers shown in Exhibit AH-5 are already presented at the Texas jurisdictional level. Therefore, the final RR of $19,734,519 is calculated on line 10 of Exhibit AH-5 by adding the revreqt of $12,388,584 (line 8) plus the ATC of $7,345,936 (line 9).

Q148. DOES EPE INTEND TO FILE A TCRF RATE RIDER IN THIS PROCEEDING?

A. No. EPE seeks approval of a new TCRF baseline in this proceeding allowing for future cost recovery "for reasonable and necessary costs for transmission infrastructure improvement and changes in wholesale rates that are appropriately allocated to Texas retail customers." Any future rate rider filing will be made pursuant to 16 TAC § 25.239(d) and will calculate the incremental transmission revenue requirement and the associated TCRF rates by customer rate class. Revising the baseline in this case will allow EPE to evaluate whether a TCRF proceeding in the future is warranted.

X. Baseline for Generation Cost Recovery Rider

Q149. WHAT IS A GENERATION COST RECOVERY RIDER?

A. Generation Cost Recovery Rider ("GCRR") is a rate mechanism approved by the Texas Legislature that allows an electric utility to recover its investment in a power generation facility outside of a base-rate proceeding.

Q150. HAS THE COMMISSION ADOPTED A RULE TO IMPLEMENT A GCRR?

A. Yes. The Commission has adopted 16 TAC § 25.248 ("GCRR Rule") to implement a GCRR as described by PURA § 36.2133.

Q151. WHAT RELIEF IS EPE SEEKING IN THIS PROCEEDING WITH RESPECT TO THE ESTABLISHMENT OF THE GCRR?

A. In this proceeding, EPE is establishing the GCRR baseline values for the components that are used for a subsequent implementation of the GCRR. Accordingly, with the approval and implementation of base rates reflecting EPE's Test Year adjusted generation costs, the GCRR rates will also be set to zero.

Q152. WHAT BASELINE VALUES ARE REQUIRED BY THE SUBSTANTIVE RULE?

A. The GCRR Rule requires the following baseline values based on those utilized to establish rates in the Company's most recent base-rate proceeding.

(1) TRAF – the Texas retail jurisdictional production allocation factor,

(2) $BD_{RC\text{-}CLASS}$ – the rate class billing determinants used to establish generation base rates with energy-based billing determinants used for those rate classes that do not include any demand charges and demand-based billing determinants for those rate classes that include rate-demand charges,

(3) ROR_{RC} – the after-tax rate of return approved by the Commission, and

(4) $ALLOC_{RC\text{-}CLASS}$ – the rate class allocation factor values.

[3]Two sections number 36.213 were added by the 86th Texas Legislature.

Q153. SINCE EPE HAS DIFFERENT TYPES OF GENERATION, IS EPE PROPOSING MORE THAN ONE PRODUCTION ALLOCATION FACTOR?

A. Yes. Since EPE is requesting that Newman Unit 6 be treated as a dedicated facility to serve Texas 100%, a jurisdictional allocation would not work. Therefore, to account for different types of generation facilities (i.e., peaking or load-following) and different regulatory treatment (i.e., system resource or dedicated), EPE seeks to establish more than one Texas retail jurisdictional production allocation factor in this proceeding.

Q154. HAVE YOU PREPARED AN EXHIBIT THAT SETS FORTH THE BASELINE VALUES DESCRIBED ABOVE?

A. Yes. Exhibit AH-6 sets forth the GCRR baseline values described above that can be utilized by EPE in a subsequent GCRR proceeding, which are derived from information included in this base rate case.

XI. Baseline for Purchase Power Capacity Cost Recovery Factor

Q155. WHAT IS A PURCHASED POWER CAPACITY COST RECOVERY FACTOR?

A. Purchased Power Capacity Cost Recovery Factor ("PCRF") is a rate mechanism approved by the Texas Legislature that allows electric utilities to recover costs associated with purchasing power capacity from external suppliers.

Q156. HAS EPE IMPLEMENTED A PCRF?

A. No. EPE currently does not have a PCRF.

Q157. WHAT IS EPE REQUESTING IN THIS CASE RELATED TO A PCRF?

A. EPE is requesting to establish a PCRF baseline in this case to serve as a reference point against which cost adjustments will be measured in the future.

Q158. WHAT FORMULA DOES 16 TAC § 25.238 PRESCRIBE FOR SETTING THE PCRF?

A. 16 TAC § 25.238 prescribes the following formula:

$$PCRF = (\{(((PPC_{CY} + AAC_{CY} + APC_{M}) * TRAF_{CY}) – OSM_{CY}) * CAF_{CY}\} – \{(PPC_{RC\text{-}CLASS} + APC_{RC\text{-}CLASS}) * LGR\} – \{((PCIC_{RC\text{-}CLASS} * ROR_{AT}) + PCDEP_{RC\text{-}CLASS} + PCFIT_{RC\text{-}CLASS} + PCOT_{RC\text{-}CLASS}) * LGI\} + CTU) / CBD_{E}$$

Q159. HOW DID YOU CALCULATE THE PCRF BASELINE VALUES?

A. Similar to the calculation of EPE's other baselines, I used the cost-of-service model to calculate the baselines. For the PCRF, I used a combination of the Production values from the FCOS, the Texas values from the JCOS, and the results of the Texas rate classes in the CCOS.

Q160. WHAT ALLOCATION FACTORS WERE USED TO DETERMINE THE PCRF BASELINES?

A. As previously mentioned, EPE allocates its generation in different ways depending on the type of generation facility (i.e., base load, load-following, or peaking) or the regulatory treatment of those facilities such as the direct assignment of Newman Unit 6 to the Texas jurisdiction. Therefore, EPE's PCRF baseline results incorporate all of EPE's demand production allocation factors discussed in previous sections.

Q161. DOES EPE HAVE ANY PURCHASED POWER CAPACITY COSTS? WHAT ABOUT MARGINS FROM WHOLESALE CAPACITY SALES?

A. EPE has purchased power capacity costs from entities that are not affiliates (PPC) which is shown on line 1 of Exhibit AH-7, but EPE does not have purchased power capacity costs from affiliates (APC).

Q162. DOES EPE HAVE ANY MARGINS FROM WHOLESALE CAPACITY SALES?

A. No. EPE does not have any margins from wholesale power capacity sales (OSM).

Q163. HOW DID YOU CALCULATE NET PRODUCTION CAPACITY INVESTED CAPITAL (PCIC)?

A. I took the plant in service amounts recorded in plant accounts 303, 310-317, 320-326, and 340-347, less accumulated depreciation and adjusted for changes in production capacity-related accumulated deferred income taxes (ADFIT).

Q164. WHAT IS THE WACC BEING USED AS THE RATE OF RETURN (ROR) FOR THE PCRF?

A. The Company's requested WACC of 8.363% is used to calculate return on PCIC as shown on line 5 of Exhibit AH-7.

Q165. WHAT IS THE DEPRECIATION EXPENSE INCLUDED IN THE PCRF?

A. The depreciation expense associated with the plant accounts included in the PCIC are used to determine the Depreciation expense, as related to gross production capacity shown in line 6 of Exhibit AH-7.

Q166. WHAT ARE THE INCOME AND OTHER TAXES INCLUDED IN THE PCRF BASELINES?

A. The federal income tax, as related production invested capital (PCFIT) is calculated on the return on PCIC and is shown in line 7 of Exhibit AH-7. The other taxes, as related to net production capacity (PCOT) such as property taxes is shown in line 8.

Q167. WHAT VALUES IS EPE ASKING THE COMMISSION TO SET FOR PURPOSES OF ESTABLISHING A PCRF?

A. EPE is asking the Commission to establish the PCRF baseline values that are shown in Exhibit AH-7.

Q168. DOES EPE INTEND TO FILE A PCRF RATE RIDER IN THIS PROCEEDING?

A. No.

XII. Retiring Plant Rider

Q169. WHAT IS THE RETIRING PLANT RIDER?

A. The Retiring Plant Rider was a rider that was created in the settlement of EPE's last base rate proceeding, Docket No. 52195. At that time, there were several of EPE's older plants that EPE was planning to retire in the near future, Newman Units 1 and 2, and Rio

Grande 7. In the settlement of that case, the costs for these plants were considered to have been removed from base-rates and placed into a rider that would be adjusted accordingly as each unit in the rider was retired. The intent of the rider was to allow customers to see the benefits of reduced costs from the retirement of the plants as they occurred rather than waiting for EPE's next base rate proceeding for their removal from EPE's cost of service. As it happened, these plants have not yet been retired.

Q170. WHAT IS EPE PROPOSING TO DO WITH THE RETIRING PLANT RIDER?

A. EPE is seeking to continue the Retiring Plant Rider Factor ("RPRF") for Newman Units 1 and 2 and Rio Grande 7. In addition, EPE is proposing to include Rio Grande Unit 6 in the RPRF.

Q171. WHY IS EPE CONTINUING THE RPRF?

A. Newman Units 1 and 2 and Rio Grande Units 6 and 7 continue to operate despite their retirement status. Instead of including them in EPE's base revenue requirement where they would remain for a number of years embedded within base rates, EPE is proposing to recover them in a separate rider (Schedule No. RPRF[4]) while they continue to operate and then adjust the rider as each unit ceases its operations[5].

Q172. HOW ARE THE REVENUE REQUIREMENTS FOR EACH OF THE FOUR UNITS IN THE RPRF DETERMINED?

A. The revenue requirement for the units currently included in the RPRF (Newman Unit 1, Newman Unit 2, and Rio Grande unit 7) will remain the same as it was established in the prior rate case. It will be determined by a return on rate base plus non-labor operation and maintenance expenses, depreciation expense, and taxes (both income taxes and taxes other than income taxes).

Rio Grande Unit 6, as EPE witness David Rodriguez explains in his direct testimony, will only include its non-labor operation and maintenance expenses in the revenue requirement to be recovered in the RPRF.

[4] Refer to EPE witness Manuel Carrasco's direct testimony for more on Schedule No. RPRF.
[5] Refer to EPE witness David Rodriguez' direct testimony for the operations of the generation facilities.

Q173. WHAT ARE THE REVENUE REQUIREMENTS FOR EACH OF THE FOUR UNITS IN THE RPRF?

A. Exhibit AH-8 presents the revenue requirement calculations and the resulting allocation to Texas.

XIII. Texas AMS Surcharge Revision

Q174. WHY IS EPE ASKING TO REVISE ITS TEXAS AMS SURCHARGE?

A. The operational cost savings that were included in the Texas AMS Surcharge calculation are now mostly realized in our actual test year O&M. Therefore, if the estimated savings remained in the Texas AMS surcharge, EPE would be double counting the savings.

Q175. HOW IS EPE PROPOSING TO REDUCE THE OPERATIONAL SAVINGS IN THE TEXAS AMS SURCHARGE?

A. Rather than making an adjustment to increase the O&M in EPE's cost of service to eliminate the double-counting, it makes more sense to reduce the estimated O&M savings in the calculation of the Texas AMS surcharge. EPE will apply a proportional reduction based on the percentage of advanced meters that have been installed.

Q176. WHAT PERCENTAGE OF AMS METERS HAVE BEEN INSTALLED IN TEXAS?

A. As of the end of the test year, installation of Texas AMS meters is approximately 70% complete. Therefore, EPE is proposing to reduce the estimated savings included in the original AMS filing by the same percentage.

Q177. WHAT ARE THE RESULTS OF THIS CHANGE TO THE TEXAS AMS SURCHARGE?

A. Exhibit AH-9 summarizes the results of this change to reduce the estimated O&M savings from the Texas AMS revenue requirement calculation.

XIV. Summary and Conclusion

Q178. PLEASE SUMMARIZE YOUR TESTIMONY.

A. The JCOS for the test year ended September 30, 2024, results in a total revenue requirement of $934.4 million and a base revenue requirement of $713.3 million for the Texas jurisdiction. The base revenue deficiency is $85.7 million.

The CCOS shows the assignment of the revenue requirements discussed above to each rate class. Table 5 summarizes the CCOS, and the resulting rate increase required to achieve an equalized rate of return across rate classes. The resulting firm base revenue requirements (net of non-firm revenues) for each class are shown on line 1 of Schedule P-1.04.

The DEC study results in the assignment of the $709.8 million firm base revenue requirement (net of non-firm revenues) to each DEC component by Texas rate class. The summary of these results can be seen on Schedule P-6.

I established the baseline revenue requirements and values for potential future filings of the DCRF, TCRF, GCRR, and PCRF rates.

I re-calculated a revenue requirement for each of the facilities to include in the Retiring Plant Rider.

I proposed a revision to the AMS surcharge to proportionally reduce the estimated savings in the surcharge based on the percentage of completed installations of advanced meters in Texas at the end of the test year.

Q179. IN YOUR OPINION, ARE THE ALLOCATION METHODS AND THE RESULTS OF THE ALLOCATIONS EMPLOYED IN EPE'S COST-OF-SERVICE STUDIES FAIR AND REASONABLE?

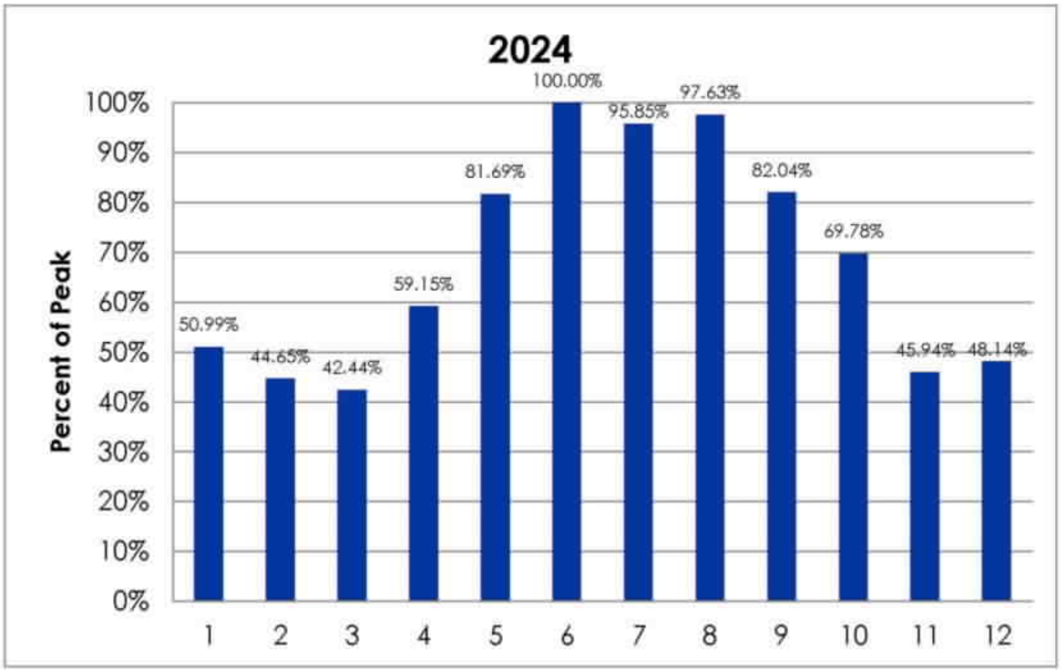
A. Yes. The allocation methods employed in EPE's cost-of-service studies are fair and reasonable and accurately present the costs to serve each jurisdiction and rate class. Furthermore, the methods that have been employed in conducting the cost-of-service studies utilize well-reasoned methods which are commonly employed in the electric utility industry.

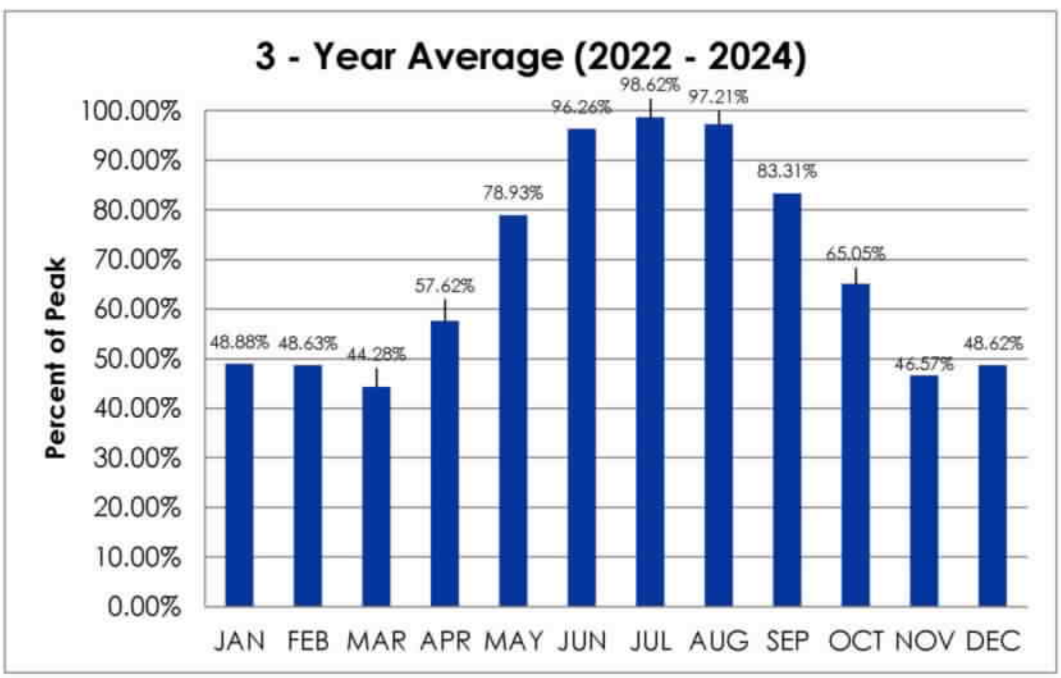
Q180. DOES THIS CONCLUDE YOUR TESTIMONY?

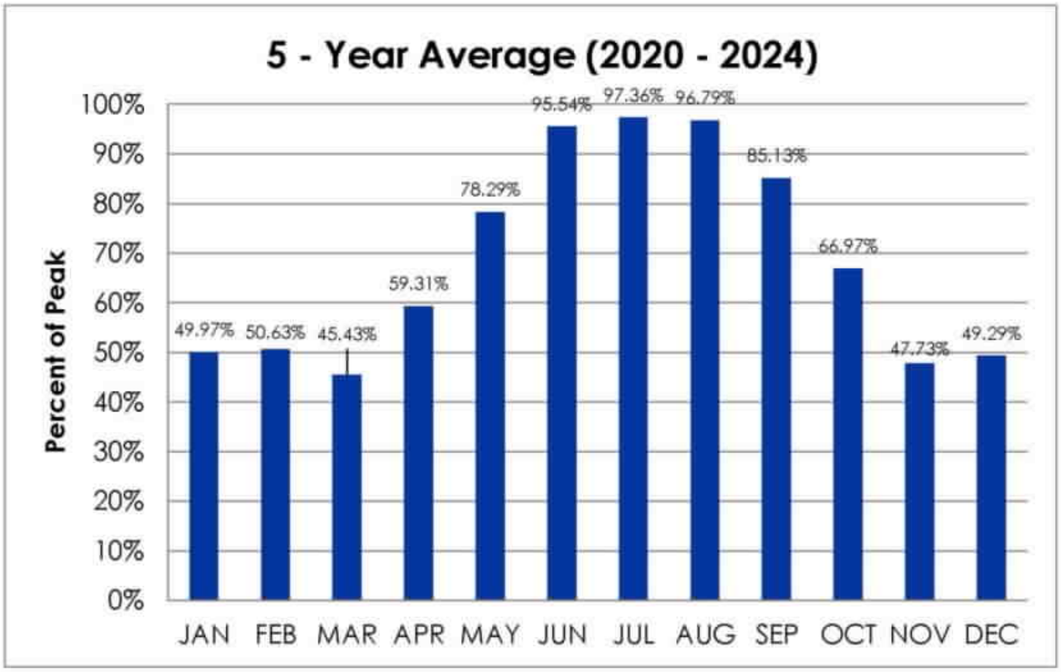
A. Yes, it does.

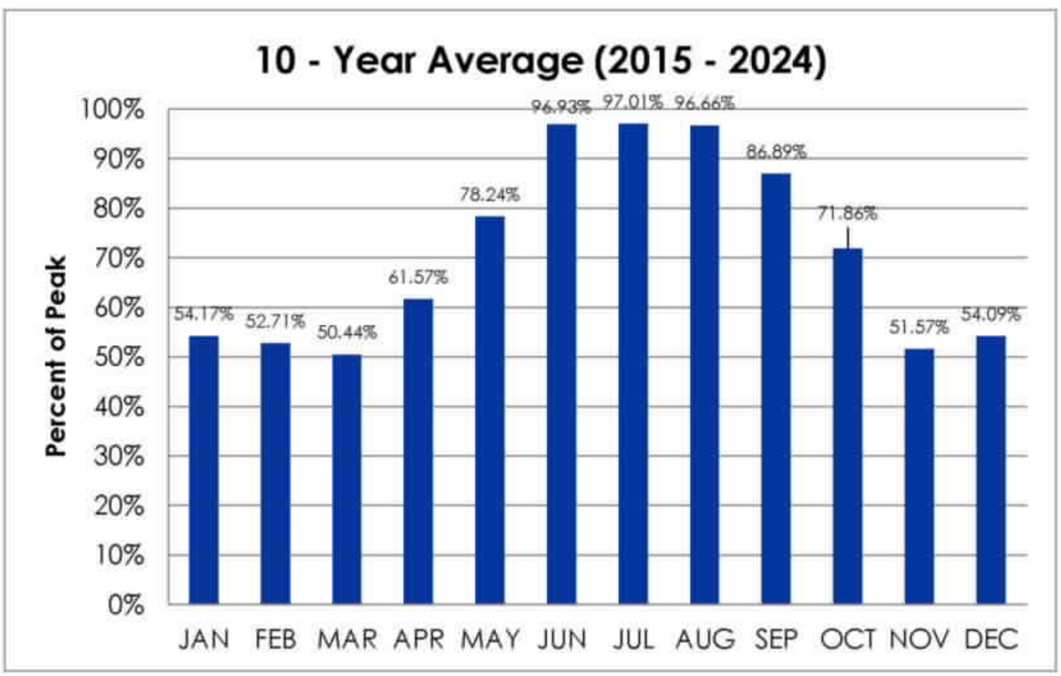
SCHEDULES SPONSORED BY A. HERNANDEZ

Schedule	Description	Sponsorship
A-1	COST OF SERVICE - TEXAS RETAIL	Sponsor
B-1.1	TEXAS RETAIL	Sponsor
O-5	VARIABILITY OF AVERAGE FUEL COSTS WITH KWH SALES	Sponsor
P	CLASS COST OF SERVICE ANALYSIS	Sponsor
P-1.1	PROPOSED RATE SCHEDULES / PROPOSED RATE CLASSES	Sponsor
P-1.2	EXISTING RATE SCHEDULES / PROPOSED RATE CLASSES	Sponsor
P-1.3	EXISTING RATE SCHEDULES / EXISTING RATE CLASSES	Sponsor
P-1.4	PROPOSED RATE SCHEDULES / EXISTING RATE CLASSES	Sponsor
P-1.5	FINANCIAL DATA FOR NON-INVESTOR-OWNED UTILITIES	Sponsor
P-2	ALLOCATION OF EXPENSES TO PROPOSED RATE CLASSES	Sponsor
P-3	ALLOCATION OF RATE BASE TO PROPOSED RATE CLASSES	Sponsor
P-4	SEPARATION OF EXPENSES	Sponsor
P-5	SEPARATION OF RATE BASE	Sponsor
P-6	UNIT COST ANALYSIS	Sponsor
P-7	ALLOCATION FACTORS	Sponsor
P-8	CLASSIFICATION FACTORS	Sponsor
P-10	PAYROLL EXPENSE DISTRIBUTION	Sponsor
P-11	DISTRIBUTION PLANT STUDY	Sponsor
P-12	SUPPORT FOR PRODUCTION ALLOCATION METHODOLOGY	Sponsor
P-13	SUMMARY OF CHANGES IN ALLOCATION FACTORS	Sponsor


2024
Percent of Peak
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
50.99%
44.65%
42.44%
59.15%
81.69%
100.00%
95.85%
97.63%
82.04%
69.78%
45.94%
48.14%
1
2
3
4
5
6
7
8
9
10
11
12


3 - Year Average (2022 - 2024)
Percent of Peak
100.00%
90.00%
80.00%
70.00%
60.00%
50.00%
40.00%
30.00%
20.00%
10.00%
0.00%
48.88%
48.63%
44.28%
57.62%
78.93%
96.26%
98.62%
97.21%
83.31%
65.05%
46.57%
48.62%
JAN
FEB
MAR
APR
MAY
JUN
JUL
AUG
SEP
OCT
NOV
DEC


5 - Year Average (2020 - 2024)
Percent of Peak
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
49.97%
50.63%
45.43%
59.31%
78.29%
95.54%
97.36%
96.79%
85.13%
66.97%
47.73%
49.29%
JAN FEB MAR APR MAY JUN JUL AUG SEP OCT NOV DEC


10 - Year Average (2015 - 2024)
Percent of Peak
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
54.17%
52.71%
50.44%
61.57%
78.24%
96.93%
97.01%
96.66%
86.89%
71.86%
51.57%
54.09%
JAN FEB MAR APR MAY JUN JUL AUG SEP OCT NOV DEC

EL PASO ELECTRIC COMPANY
TX COMMUNITY/BUSINESS SOLAR DIRECT ASIGNMENTS

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
Line No.	Description	PB - Functional Class	PB - Depr Summary	PB - Depr Group	REG - Plant Description	BUD - Operating Segment	REG - Function	REG - Jurisdiction Allocator	Other
1	Plant in Service	Other Production	341 - Structures and improvements	4:1703410 SOLAR-STRU&IMPR(TXCOMSOL)	Renewable Solar-Montana	170: RENEWABLE - SOLAR	Production	DIRECT_OTHER: Direct Assign Other	749,279
2	Plant in Service	Other Production	344 - Generators	4:1703440 SOLAR-GENERATORS(TXCOMSOL	Renewable Solar-Montana	170: RENEWABLE - SOLAR	Production	DIRECT_OTHER: Direct Assign Other	5,457,408
3	Plant in Service	Other Production	345 - Accessory electric equipment	4:1703450 SOLAR-ACCES ELEC(TXCOMMU	Renewable Solar-Montana	170: RENEWABLE - SOLAR	Production	DIRECT_OTHER: Direct Assign Other	891,784
4	Plant in Service	Other Production	346 - Misc power plant equipment	4:1703460 SOLAR-MISC PWRPLT(TXCOMMU	Renewable Solar-Montana	170: RENEWABLE - SOLAR	Production	DIRECT_OTHER: Direct Assign Other	64,376
5	Plant in Service								**7,162,847**
6	Accum Depreciation & Amortization	Other Production	341 - Structures and improvements	4:1703410 SOLAR-STRU&IMPR(TXCOMSOL)	Renewable Solar-Montana	170: RENEWABLE - SOLAR	Production	DIRECT_OTHER: Direct Assign Other	(182,434)
7	Accum Depreciation & Amortization	Other Production	344 - Generators	4:1703440 SOLAR-GENERATORS(TXCOMSOL	Renewable Solar-Montana	170: RENEWABLE - SOLAR	Production	DIRECT_OTHER: Direct Assign Other	(1,328,769)
8	Accum Depreciation & Amortization	Other Production	345 - Accessory electric equipment	4:1703450 SOLAR-ACCES ELEC(TXCOMMU	Renewable Solar-Montana	170: RENEWABLE - SOLAR	Production	DIRECT_OTHER: Direct Assign Other	(217,131)
9	Accum Depreciation & Amortization	Other Production	346 - Misc power plant equipment	4:1703460 SOLAR-MISC PWRPLT(TXCOMMU	Renewable Solar-Montana	170: RENEWABLE - SOLAR	Production	DIRECT_OTHER: Direct Assign Other	(15,674)
10	Accum Depreciation & Amortization								**(1,744,009)**
11	Depreciation Expenses	Other Production	341 - Structures and improvements	4:1703410 SOLAR-STRU&IMPR(TXCOMSOL)	Renewable Solar-Montana	170: RENEWABLE - SOLAR	Production	DIRECT_OTHER: Direct Assign Other	24,951
12	Depreciation Expenses	Other Production	344 - Generators	4:1703440 SOLAR-GENERATORS(TXCOMSOL	Renewable Solar-Montana	170: RENEWABLE - SOLAR	Production	DIRECT_OTHER: Direct Assign Other	181,732
13	Depreciation Expenses	Other Production	345 - Accessory electric equipment	4:1703450 SOLAR-ACCES ELEC(TXCOMMU	Renewable Solar-Montana	170: RENEWABLE - SOLAR	Production	DIRECT_OTHER: Direct Assign Other	29,696
14	Depreciation Expenses	Other Production	346 - Misc power plant equipment	4:1703460 SOLAR-MISC PWRPLT(TXCOMMU	Renewable Solar-Montana	170: RENEWABLE - SOLAR	Production	DIRECT_OTHER: Direct Assign Other	2,144
15	Depreciation Expenses								**238,523**

	(a)	(b)	(c)	(d)	(e)	(f)	(g)
Line No.	Account Type	REG - FERC Account	BUD - Operating Segment	BUD - Project	REG - Function	REG - Jurisdiction Allocator	Other
1	O&M - Other Power Generation Operations	546.000: Oper Superv and Eng	170: RENEWABLE - SOLAR	GS702: TX COMMUNITY SOLAR BLKT	Production	DIRECT_OTHER: Direct Assign Other	10,000
2	O&M - Other Power Generation Operations	550.000: Rents	170: RENEWABLE - SOLAR	GS734: O&M FOR TEXAS BUSINESS POWER SOLAR	Production	DIRECT_OTHER: Direct Assign Other	104,124
3	O&M - Other Power Generation Operations						**114,124**
4	O&M - Other Power Generation Maintenance	553.000: Maint Gen and Elec Plt	170: RENEWABLE - SOLAR	GS702: TX COMMUNITY SOLAR BLKT	Production	DIRECT_OTHER: Direct Assign Other	594,072
5	O&M - Other Power Generation Maintenance						**594,072**
6	O&M - Administration & General Exp	925.000: Injuries and Damages	170: RENEWABLE - SOLAR	GS124: TEXAS COMMUNITY SOLAR EXPANSION	Production	DIRECT_OTHER: Direct Assign Other	1
7	O&M - Administration & General Exp	925.000: Injuries and Damages	170: RENEWABLE - SOLAR	GS125: TEXAS BUSINESS SOLAR 50MW	Production	DIRECT_OTHER: Direct Assign Other	0
8	O&M - Administration & General Exp	926.000: Employee Pens and Bens	170: RENEWABLE - SOLAR	GS124: TEXAS COMMUNITY SOLAR EXPANSION	Production	DIRECT_OTHER: Direct Assign Other	82
9	O&M - Administration & General Exp	926.000: Employee Pens and Bens	170: RENEWABLE - SOLAR	GS125: TEXAS BUSINESS SOLAR 50MW	Production	DIRECT_OTHER: Direct Assign Other	10
10	O&M - Administration & General Exp						**94**

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)	(s)
Line No.	DCRF Summary	Total	TX Rate 01 - Residential	TX Rate 02 - Small General Service	TX Rate 07 - Recreational Lighting	TX Rate 08 - Street Lighting	TX Rate 09 - Traffic Signals	TX Rate 11 - Municipal Pumping	TX Rate 15 - Electric Refining	TX Rate 22 - Irrigation Service	TX Rate 24 - General Service	TX Rate 25 - Large Power	TX Rate 26 - Petroleum Refinery	TX Rate 28 - Area Lighting	TX Rate 30 - Electric Furnace	TX Rate 31 - Military Reservation	TX Rate 34 - Cotton Gin	TX Rate 41 - City and County	TX Rate WH - Water Heating
1	DIC_{RC}	$865,221,851	$510,951,730	$63,646,289	$2,058,660	$7,162,758	$83,578	$15,819,610	$718	$746,718	$173,500,296	$46,720,281	$1,994	$10,175,787	$558	$3,430	$450,871	$32,418,727	$1,479,848
2	ROR_{AT}		8.363%	8.363%	8.363%	8.363%	8.363%	8.363%	8.363%	8.363%	8.363%	8.363%	8.363%	8.363%	8.363%	8.363%	8.363%	8.363%	8.363%
3	$DDEPR_{RC}$	40,453,784	24,565,755	3,054,357	91,051	510,093	3,805	676,481	213	34,001	7,475,524	1,967,273	592	607,435	166	1,019	19,143	1,377,362	69,516
4	$DFIT_{RC}$	12,038,221	7,074,020	880,159	28,860	100,648	1,167	222,736	(0)	10,433	2,438,592	657,465	(0)	141,175	(0)	(1)	6,342	456,080	20,546
5	DOT_{RC}	43,660,255	26,701,389	3,348,306	98,125	380,244	4,123	726,974	299	36,439	8,088,800	2,155,897	830	521,644	233	1,428	20,865	1,499,252	75,407
6	$DISTREV_{RC}$	$168,511,625	$101,072,566	$12,605,624	$390,203	$1,590,013	$16,084	$2,949,201	$572	$143,322	$32,512,919	$8,687,898	$1,589	$2,121,264	$445	$2,733	$84,057	$6,043,904	$289,230
7	$ALLOC_{CLASS}$		59.0544%	7.3561%	0.2379%	0.8279%	0.0097%	1.8284%	0.0001%	0.0863%	20.0527%	5.3998%	0.0002%	1.1761%	0.0001%	0.0004%	0.0521%	3.7469%	0.1710%
8	$BD_{RC-CLASS}$		2,542,622,734	403,529,142	5,752,352	36,621,946	2,625,336	177,639,371	90,000	2,749,906	4,935,841	1,461,703	677,221	20,325,027	67,232	612,000	5,450	754,763	3,636,411
9	$BD_{RC-CLASS}$ BASIS		KWH	KWH	KWH	KWH	KWH	KWH	KW	KWH	KW	KW	KW	KWH	KW	KW	KW	KW	KWH

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)	(s)
Line No.	TCRF Summary	Total	TX Rate 01 - Residential	TX Rate 02 - Small General Service	TX Rate 07 - Recreational Lighting	TX Rate 08 - Street Lighting	TX Rate 09 - Traffic Signals	TX Rate 11 - Municipal Pumping	TX Rate 15 - Electric Refining	TX Rate 22 - Irrigation Service	TX Rate 24 - General Service	TX Rate 25 - Large Power	TX Rate 26 - Petroleum Refinery	TX Rate 28 - Area Lighting	TX Rate 30 - Electric Furnace	TX Rate 31 - Military Reservation	TX Rate 34 - Cotton Gin	TX Rate 41 - City and County	TX Rate WH - Water Heating
1	TIC	$308,642,136	$162,817,939	$21,808,743	$936	$2,160	$37,983	$3,690,087	$1,430,394	$151,933	$62,462,236	$22,301,151	$10,773,493	$1,225	$1,015,639	$10,343,224	$2,418	$11,744,188	$58,386
2	ROR		8.363%	8.363%	8.363%	8.363%	8.363%	8.363%	8.363%	8.363%	8.363%	8.363%	8.363%	8.363%	8.363%	8.363%	8.363%	8.363%	8.363%
3	RTIC	25,812,049	13,616,626	1,823,887	78	181	3,177	308,606	119,625	12,706	5,223,779	1,865,067	900,998	102	84,939	865,014	202	982,178	4,883
4	TDEPR	9,308,552	4,911,514	657,801			1,145	111,173	43,105	4,585	1,883,635	672,372	324,718		30,609	311,835	72	354,230	1,759
5	TFIT	4,239,536	2,236,407	299,562	15	35	522	50,696	19,651	2,087	858,003	306,348	148,001	20	13,953	142,084	33	161,317	802
6	TOT	8,857,542	4,673,545	625,930			1,089	105,786	41,017	4,363	1,792,371	639,795	308,985		29,126	296,726	68	337,067	1,674
7	TREVCRED	(35,829,095)	(18,905,736)	(2,531,973)	31	71	(4,405)	(427,779)	(165,875)	(17,650)	(7,249,981)	(2,587,752)	(1,249,631)	40	(117,790)	(1,200,143)	(274)	(1,363,482)	(6,767)
8	Revreqt	12,388,584	6,532,357	875,208	124	287	1,527	148,482	57,523	6,091	2,507,806	895,831	433,072	163	40,836	415,516	101	471,311	2,350
9	ATC	7,345,936	3,875,970	519,110			903	87,733	34,017	3,618	1,486,489	530,609	256,255		24,155	246,087	56	279,544	1,388
10	RR	19,734,519	$10,408,326	$1,394,318	$124	$287	$2,431	$236,215	$91,539	$9,709	$3,994,295	$1,426,440	$689,326	$163	$64,991	$661,603	$158	$750,855	$3,738
11	ClassALLOC		52.7417%	7.0654%	0.0006%	0.0015%	0.0123%	1.1970%	0.4639%	0.0492%	20.2401%	7.2281%	3.4930%	0.0008%	0.3293%	3.3525%	0.0008%	3.8048%	0.0189%
12	BD		2,542,622,734	403,529,142	5,752,352	36,621,946	2,625,336	177,639,371	90,000	2,749,906	4,935,841	1,461,703	677,221	20,325,027	67,232	612,000	5,450	754,763	3,636,411
13	BD BASIS		KWH	KWH	KWH	KWH	KWH	KWH	KW	KWH	KW	KW	KW	KWH	KW	KW	KW	KW	KWH

EL PASO ELECTRIC COMPANY
Generation Cost Recovery Rider
Baseline Values
For the Test Year Ended September 30, 2024

		Dedicated Facility DIRECT_TX	Load-Following Facility D1PROD	Peaking Facility D2PROD	Base Load Facility DPROD12
1	Texas Retail Jurisdictional Production Allocation Factor (TRAF)	100.000%	77.472%	77.385%	76.199%

2 Rate Class Billing Determinants ($BD_{RC\text{-}CLASS}$)

		Billing Determinants	Basis
TXRT01	Residential Service	2,542,622,734	kWh
TXRT02	Small General Service	403,529,142	kWh
TXRT07	Outdoor Recreational Lighting Service	5,752,352	kWh
TXRT08	Street Lighting	36,621,946	kWh
TXRT09	Traffic Signals	2,625,336	kWh
TXRT11TOU	Municipal Pumping Service - TOU	177,639,371	kWh
TXRT15	Electrolytic Refining Service	90,000	kW
TXRTWH	Water Heating Service	3,636,411	kWh
TXRT22	Irrigation Service	2,749,906	kWh
TXRT24	General Service	4,935,841	kW
TXRT25	Large Power Service	1,461,703	kW
TXRT26	Petroleum Refining Service	677,221	kW
TXRT28	Private Area Lighting Service	20,325,027	kWh
TXRT30	Electric Furnace Rate	67,232	kW
TXRT31	Military Reservation Service	612,000	kW
TXRT34	Cotton Gin Service	5,450	kW
TXRT41	City and County Service	754,763	kW

3 Rate of Return (ROR_{RC}) 8.363%

4 Rate Class Allocation Factors ($ALLOC_{RC\text{-}CLASS}$)

		Load-Following Facility D1PROD	Peaking Facility D2PROD	Base Load Facility DPROD12
TXRT01	Residential Service	53.030894%	52.763458%	52.260867%
TXRT02	Small General Service	7.050675%	7.066635%	7.001572%
TXRT07	Outdoor Recreational Lighting Service	0.042322%	0.000000%	0.185799%
TXRT08	Street Lighting	0.269504%	0.000000%	0.269504%
TXRT09	Traffic Signals	0.015139%	0.012297%	0.015139%
TXRT11TOU	Municipal Pumping Service - TOU	1.298244%	1.194308%	1.298244%
TXRT15	Electrolytic Refining Service	0.449790%	0.463069%	0.644653%
TXRTWH	Water Heating Service	0.026761%	0.018894%	0.026761%
TXRT22	Irrigation Service	0.049205%	0.049253%	0.031254%
TXRT24	General Service	19.898149%	20.235531%	19.639263%
TXRT25	Large Power Service	7.006495%	7.223169%	7.116578%
TXRT26	Petroleum Refining Service	3.307938%	3.488388%	3.357212%
TXRT28	Private Area Lighting Service	0.149573%	0.000000%	0.149573%
TXRT30	Electric Furnace Rate	0.327216%	0.328824%	0.534116%
TXRT31	Military Reservation Service	3.281610%	3.349979%	3.785449%
TXRT34	Cotton Gin Service	0.008306%	0.000769%	0.008306%
TXRT41	City and County Service	3.788181%	3.805427%	3.675710%
		100.000000%	100.000000%	100.000000%

	(a)	(b)	(c)	(d)	(c)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)	(s)
Line No.	PCRF Summary	Total	TX Rate 01 - Residential	TX Rate 02 - Small General Service	TX Rate 07 - Recreational Lighting	TX Rate 08 - Street Lighting	TX Rate 09 - Traffic Signals	TX Rate 11 - Municipal Pumping	TX Rate 15 - Electric Refining	TX Rate 22 - Irrigation Service	TX Rate 24 - General Service	TX Rate 25 - Large Power	TX Rate 26 - Petroleum Refinery	TX Rate 28 - Area Lighting	TX Rate 30 - Electric Furnace	TX Rate 31 - Military Reservation	TX Rate 34 - Cotton Gin	TX Rate 41 - City and County	TX Rate WH - Water Heating
1	PPC_{RC}	$3,402,071	$1,804,149	$239,869	$1,440	$9,169	$515	$44,167	$15,302	$1,674	$676,949	$238,366	$112,538	$5,089	$11,132	$111,643	$283	$128,877	$910
2	APC_{RC}																		
3	OSM_{RC}																		
4	$PCIC_{RC}$	1,471,726,287	773,723,486	103,524,640	1,257,520	2,506,429	208,117	18,612,569	7,875,942	616,046	293,334,863	105,134,982	50,127,452	1,391,057	6,069,609	51,750,295	81,457	55,159,501	352,322
5	ROR_{AT}		8.363%	8.363%	8.363%	8.363%	8.363%	8.363%	8.363%	8.363%	8.363%	8.363%	8.363%	8.363%	8.363%	8.363%	8.363%	8.363%	8.363%
6	$PCDEP_{RC}$	70,402,709	36,888,460	4,944,347	56,613	141,219	10,376	917,609	369,385	30,249	14,078,528	5,057,052	2,428,003	78,376	280,115	2,459,705	4,505	2,640,390	17,777
7	$PCFIT_{RC}$	27,601,073	14,504,259	1,941,129	24,177	47,381	3,911	349,608	148,478	11,485	5,501,104	1,972,886	941,014	26,296	114,595	972,605	1,538	1,033,982	6,625
8	$PCOT_{RC}$	9,448,084	4,969,154	664,485	9,000	17,612	1,348	119,632	51,350	3,870	1,878,573	673,075	319,934	9,775	39,953	333,933	565	353,526	2,299
9	CBD_{RC}		2,542,622,734	403,529,142	5,752,352	36,621,946	2,625,336	177,639,371	90,000	2,749,906	4,935,841	1,461,703	677,221	20,325,027	67,232	612,000	5,450	754,763	3,636,411
10	CBD_{RC} BASIS		KWH	KWH	KWH	KWH	KWH	KWH	KW	KWH	KW	KW	KW	KWH	KW	KW	KW	KW	KWH

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
Line No.	Description	NEWMAN - UNIT 1	NEWMAN - UNIT 2	RIO GRANDE - UNIT 6	RIO GRANDE - UNIT 7	Total	TX Allocation	Texas RPRF
1	**Retiring Plant Rider Revenue Requirements**							
2	Plant in Service	$ 31,501,526	$ 34,821,604	$ 0	$ 16,398,309	$ 82,721,439	77.4718%	$64,085,788
3	Accumulated Depreciation	(28,671,366)	(26,490,724)	0	(13,047,661)	(68,209,751)	77.4718%	($52,843,322)
4	Net Plant in Service	2,830,160	8,330,880	0	3,350,648	14,511,688		$11,242,466
5	Accumulated Deferred Income Taxes	(594,334)	(1,749,485)	0	(703,636)	(3,047,455)	77.4718%	($2,360,918)
6	Total Rate Base	2,235,827	6,581,395	0	2,647,012	11,464,234		$8,881,548
7	Rate of Return	8.363%	8.363%	8.363%	8.363%			8.363%
8	Return on Rate Base	186,984	550,409	0	221,372	958,765		$742,773
9	**Cost of Service**							
10	Other Operation and Maintenance (Non-Labor)	901,959	2,819,007	879,448	1,135,956	5,736,370	77.4718%	$4,444,069
11	Depreciation and Amortization	1,007,076	2,683,347	0	1,578,915	5,269,337	77.4718%	$4,082,250
12	Taxes Other Than Income Taxes	12,987	38,229	0	113,225	164,442	77.4718%	$127,396
13	State Income Taxes	3,472	10,219	0	4,110	17,800	77.4718%	$13,790
14	Federal Income Tax	35,873	105,595	0	42,470	183,938	77.4718%	$142,500
15	Return	186,984	550,409	0	221,372	958,765	77.4718%	$742,773
16	Total Revenue Requirement	$ 2,148,350	$ 6,206,805	$ 879,448	$ 3,096,048	$ 12,330,652		$9,552,778
17								
	Federal Income Tax							
18	Return	186,984	550,409	0	221,372	958,765		
	Deduct:							
19	Interest	(52,035)	(153,169)	0	(61,604)	(266,808)		
20	Amortization of investment tax credits	0	0	0	0	0		
21	Amort of excess deferred income taxes	0	0	0	0	0		
22	AEFUDC Depreciation	0	0	0	0	0		
23	Taxable component of return	134,950	397,239	0	159,768	691,957		
24	Tax factor	26.5823%	26.5823%	26.5823%	26.5823%			
25	Federal income taxes before adj	35,873	105,595	0	42,470	183,938		
	Deduct:							
26	Amortization of investment tax credits	0	0	0	0	0		
27	Amort of excess deferred income taxes	0	0	0	0	0		
28	Total federal income taxes	35,873	105,595	0	42,470	183,938		
	New Mexico Income Tax							
29	Return	186,984	550,409	0	221,372	958,765		
	Deduct:							
30	Interest	(52,035)	(153,169)	0	(61,604)	(266,808)		
31	ADSIT not charged to expense	0	0	0	0	0		
32	Other state income taxes included in return	0	0	0	0	0		
33	Federal income taxes included in return	35,873	105,595	0	42,470	183,938		
34	Taxable component of return	170,823	502,834	0	202,238	875,895		
35	Tax factor	0.8987%	0.8987%	0.8987%	0.8987%			
36	New Mexico income taxes before adj	1,535	4,519	0	1,817	7,871		
	Deduct:							
37	Amortization of investment tax credits	0	0	0	0	0		
38	NM Tax credits	0	0	0	0	0		
39	New Mexico income tax expense	1,535	4,519	0	1,817	7,871		
	Arizona Income Tax							
40	Return	186,984	550,409	0	221,372	958,765		
	Deduct:							
41	Interest	(52,035)	(153,169)	0	(61,604)	(266,808)		
42	ADSIT not charged to expense	0	0	0	0	0		
43	Other state income taxes included in return	0	0	0	0	0		
44	Federal income taxes included in return	35,873	105,595	0	42,470	183,938		
45	Taxable component of return	170,823	502,834	0	202,238	875,895		
46	Tax factor	0.6790%	0.6790%	0.6790%	0.6790%			
47	Arizona income taxes before adj	1,160	3,414	0	1,373	5,947		
	Deduct:							
48	Arizona tax credits	0	0	0	0	0		
49	Amort of accum deferred income taxes	0	0	0	0	0		
50	Other Arizona differences	0	0	0	0	0		
51	Arizona income tax expense	1,160	3,414	0	1,373	5,947		
	Texas Income Tax							
52	Return	186,984	550,409	0	221,372	958,765		
	Deduct:							
53	Interest	(52,035)	(153,169)	0	(61,604)	(266,808)		
54	Other state income taxes included in return	0	0	0	0	0		
55	AEFUDC depreciation	0	0	0	0	0		
56	Federal income taxes included in return	35,873	105,595	0	42,470	183,938		
57	Taxable component of return	170,823	502,834	0	202,238	875,895		
58	Tax factor	0.4546%	0.4546%	0.4546%	0.4546%			
59	Texas income taxes before adj	777	2,286	0	919	3,982		
	Deduct:							
60	Texas tax credits	0	0	0	0	0		
61	Texas income tax expense	777	2,286	0	919	3,982		
62	NM Income Tax	1,535	4,519	0	1,817	7,871		
63	AZ Income Tax	1,160	3,414	0	1,373	5,947		
64	TX Income Tax	777	2,286	0	919	3,982		
65	State Income Tax	3,472	10,219	0	4,110	17,800		
66	Fed Income Tax	35,873	105,595	0	42,470	183,938		

Line No.	Rate Class Allocation	TX Rate 01 - Residential	TX Rate 02 - Small General Service	TX Rate 07 - Recreational Lighting	TX Rate 08 - Street Lighting	TX Rate 09 - Traffic Signals	TX Rate 11 - Municipal Pumping	TX Rate 15 - Electric Refining	TX Rate 22 - Irrigation Service	TX Rate 24 - General Service	TX Rate 25 - Large Power	TX Rate 26 - Petroleum Refinery	TX Rate 28 - Area Lighting	TX Rate 30 - Electric Furnace	TX Rate 31 - Military Reservation	TX Rate 34 - Cotton Gin	TX Rate 41 - City and County	TX Rate WH - Water Heating
1	1.000000	0.530309	0.070507	0.000423	0.002695	0.000151	0.012982	0.004498	0.000492	0.198981	0.070065	0.033079	0.001496	0.003272	0.032816	0.000083	0.037882	0.000268
16	$9,552,778	$5,065,924	$673,535	$4,043	$25,745	$1,446	$124,018	$42,967	$4,700	$1,900,826	$669,315	$316,000	$14,288	$31,258	$313,485	$793	$361,877	$2,556

EL PASO ELECTRIC COMPANY
2025 TEXAS RATE CASE
Revision of TX AMS - O&M Savings

				Pre-Deployment		Deployment										
						1	2	3	1	2	3	4	5	6	7	8
($000 unless otherwise noted)		**Year 0**	**Year 1**	**Year 2**	**Year 3**	**Year 4**	**Year 5**	**Year 6**	**Year 7**	**Year 8**	**Year 9**	**Year 10**	**Year 11**	**Year 12**	**Year 13**	**Year 14**
Original O&M Savings Estimate	($55,893,913)				$0	($1,876)	($4,252)	($5,064)	($5,208)	($5,312)	($5,419)	($5,527)	($5,638)	($5,750)	($5,865)	($5,983)
% TX AMS Meters Installed (as of 9/30/2024)							70%	70%	70%	70%	70%	70%	70%	70%	70%	70%
Revenue Requirement																
O&M Savings	($18,081,114)	$0	$0	$0	$0	($1,876)	($1,276)	($1,519)	($1,562)	($1,594)	($1,626)	($1,658)	($1,691)	($1,725)	($1,760)	($1,795)
O&M Expense	$30,232,472	$0	$0	$0	$1,085	$2,603	$2,807	$2,446	$2,439	$2,497	$2,542	$2,595	$2,649	$2,704	$2,768	$3,100
Depreciation Expense	$90,955,460	$0	$0	$0	$2,173	$6,956	$11,872	$14,771	$15,363	$14,372	$13,254	$8,207	$3,419	$568	$0	$0
Amortization Expense	$2,051,258	$0	$0	$0	$684	$684	$684	$0	$0	$0	$0	$0	$0	$0	$0	$0
Interest Expense	$9,171,672	$0	$0	$0	$320	$982	$1,632	$1,831	$1,551	$1,168	$827	$411	$129	$108	$113	$100
Property Taxes	$10,660,886	$0	$0	$0	$0	$727	$1,629	$2,294	$2,131	$1,676	$1,235	$813	$137	$20	$0	$0
Federal/State Income Taxes	$4,668,552	$0	$0	$0	$163	$500	$831	$932	$789	$595	$421	$209	$66	$55	$57	$51
Return On Equity (On Average Rate Base)	$16,007,056	$0	$0	$0	$558	$1,714	$2,848	$3,196	$2,707	$2,039	$1,443	$717	$225	$188	$196	$175
Texas Gross Receipts Tax	$2,972,780	$0	$0	$0	$102	$251	$429	$489	$478	$424	$369	$230	$101	$39	$28	$33
Total Surcharge Revenue Requirement	$148,639,024	$0	$0	$0	$5,084	$12,541	$21,455	$24,440	$23,895	$21,177	$18,465	$11,524	$5,035	$1,956	$1,403	$1,665
				Ave. RR/Year	$12,386,585	$12,386,585	$12,386,585	$12,386,585	$12,386,585	$12,386,585	$12,386,585	$12,386,585	$12,386,585	$12,386,585	$12,386,585	$12,386,585
Rate Base																
Gross Plant		$0	$0	$0	$26,464	$62,485	$94,679	$102,874	$102,874	$102,874	$102,874	$102,874	$102,874	$102,874	$102,874	$102,874
Accumulated Depreciation		$0	$0	$0	($2,173)	($9,129)	($21,001)	($35,772)	($51,135)	($65,507)	($78,761)	($98,887)	($102,306)	($102,874)	($102,874)	($102,874)
Net Plant		$0	$0	$0	$24,291	$53,355	$73,678	$67,102	$51,740	$37,367	$24,114	$3,988	$568	$0	$0	$0
Add: Reg Assets (Net of Accum Amort)		$341	$634	$1,076	($684)	($684)	($684)	$0	$0	$0	$0	$0	$0	$0	$0	$0
Net Plant with Regulatory Assets		$341	$634	$1,076	$23,607	$52,672	$72,994	$67,102	$51,740	$37,367	$24,114	$3,988	$568	$0	$0	$0
Less: Accum Deferred Tax-Meters & Infrastr		$0	$0	$0	$1,282	$3,095	$3,116	$2,932	$2,388	$1,203	($259)	($1,718)	($3,177)	($4,127)	($4,113)	($3,229)
Less: Accum Deferred Tax-Reg Assets		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Less: Accum Deferred Taxes - Removal and Net Salvage		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Other Deductions		$0	$0	$0	$1,282	$3,095	$3,116	$2,932	$2,388	$1,203	($259)	($1,718)	($3,177)	($4,127)	($4,113)	($3,229)
Ending Rate Base		$341	$634	$1,076	$22,326	$49,576	$69,878	$64,171	$49,352	$36,165	$24,373	$5,705	$3,745	$4,127	$4,113	$3,229
Average Rate Base		$170	$488	$855	$11,701	$35,951	$59,727	$67,024	$56,761	$42,758	$30,269	$15,039	$4,725	$3,936	$4,120	$3,671
Revenue Requirement		$0	$0	$0	$5,084	$12,541	$21,455	$24,440	$23,895	$21,177	$18,465	$11,524	$5,035	$1,956	$1,403	$1,665
Regulatory Asset CapEx		($341)	($634)	($1,076)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total AMS Capital Additions		$0	$0	$0	($26,464)	($36,020)	($32,194)	($8,195)	$0	$0	$0	$0	$0	$0	$0	$0
Total CapEx		($341)	($634)	($1,076)	($26,464)	($36,020)	($32,194)	($8,195)	$0	$0	$0	$0	$0	$0	$0	$0

EPE TEXAS AMS SURCHARGE
PROOF OF REVENUE FOR AMS SURCHARGES

			Tier 1 (2025-2027)			Tier 2 (2028-2034)		
1			Tier 1 (2025-2027)			Tier 2 (2028-2034)		
2	**Tariff**	**Rate Class**	**Bills**	**Charges/Meter/ Month**	**Revenues**	**Bills**	**Charges/Meter/ Month**	**Revenues**
3	**Rate Class 01**	**Residential Service**	21,050,184	$ 2.71	$ 57,045,999	33,137,616	$ 2.71	$ 89,682,674
4	**Rate Class 02**	**Small Commercial Service**	1,850,088	$ 7.70	$ 14,237,951	2,888,808	$ -	$ -
5	**Rate Class 07**	**Outdoor Recreational Lighting Service**	13,596	$ 11.21	$ 152,436	20,952	$ -	$ -
6	**Rate Class 08**	**Governmental Street Lighting Service Rate**	-	$ -	$ -	-	$ -	$ -
7	**Rate Class 09**	**Governmental Traffic Signal Service Rate**	1,728	$ 6.19	$ 10,689	2,748	$ -	$ -
8	**Rate Class 11**	**Municipal Pumping Service**	26,136	$ 14.81	$ 386,954	39,996	$ -	$ -
9	**Rate Class 15**	**Electrolytic Refining Service**	-	$ -	$ -	-	$ -	$ -
10	**Rate Class 22**	**Irrigation Service**	9,648	$ 10.45	$ 100,829	14,820	$ -	$ -
11	**Rate Class 24**	**General Service**	477,055	$ 14.43	$ 6,885,613	737,977	$ -	$ -
12	**Rate Class 25**	**Large Power Service**	10,368	$ 18.42	$ 190,989	15,852	$ -	$ -
13	**Rate Class 26**	**Petroleum Refining Service**	-	$ -	$ -	-	$ -	$ -
14	**Rate Class 28**	**Area Lighting Service Rate**	-	$ -	$ -	-	$ -	$ -
15	**Rate Class 30**	**Electric Furnace Rate**	-	$ -	$ -	-	$ -	$ -
16	**Rate Class 31**	**Military Reservation Service**	-	$ -	$ -	-	$ -	$ -
17	**Rate Class 34**	**Cotton Gin Service**	120	$ 13.11	$ 1,573	168	$ -	$ -
18	**Rate Class 41**	**City and County Service**	51,136	$ 15.54	$ 794,458	71,591	$ -	$ -
21			23,490,060		$ 79,807,490	36,930,527		$ 89,682,674
22								
23								$ 169,490,164
24							Interest	$ (12,373,964)
25							Total	$ 157,116,199

DOCKET NO. 57568

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

DIRECT TESTIMONY

OF

MANUEL CARRASCO

FOR

EL PASO ELECTRIC COMPANY

JANUARY 2025

EXECUTIVE SUMMARY

Mr. Manuel Carrasco is Manager of Rate Research in El Paso Electric Company's ("EPE" or "Company") Regulatory Policy and Rates Department. In his testimony, Mr. Carrasco describes and supports the rates and rate structures that EPE proposes in this application, based on the cost-of-service studies developed by EPE, and the analyses of the impact of the proposed rates on EPE customers. He also supports the proposed revisions to rate schedule provisions.

TABLE OF CONTENTS

SUBJECT PAGE

EXHIBITS

I. Introduction and Qualifications

Q1. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Manuel Carrasco. My business address is 100 N. Stanton Street, El Paso, Texas 79901.

Q2. HOW ARE YOU EMPLOYED?

A. I am employed by El Paso Electric Company ("EPE" or the "Company") as the Manager of Rate Research.

Q3. PLEASE SUMMARIZE YOUR EDUCATIONAL AND PROFESSIONAL QUALIFICATIONS.

A. I hold both a Bachelor's Degree in Accounting and a Master's Degree in Economics from New Mexico State University ("NMSU"). I graduated from NMSU's Accounting program, with honors, in 1995 and from NMSU's Regulatory Economics program in 1999. NMSU's Regulatory Economics program consists of specific courses related to public utilities such as revenue requirements, cost allocation, and pricing in the utility industry. This concentrated graduate program is offered by only a few universities nationwide.

My professional career began in 1993 as a rate analyst with the Utilities Department of the City of Las Cruces, New Mexico, where my responsibilities included performing cost-of-service and rate design studies; preparing fiscal budget and financial forecasts; and developing forecasts of customers, consumption, and revenues. During my tenure with the City of Las Cruces, I received increasing levels of responsibility culminating with a promotion to Manager of the Rate & Economic Analysis section. My experience also includes working as an Accountant/Analyst at Sierra Pacific Power Company and as a Senior Pricing Analyst at Colorado Springs Utilities.

I began working for EPE in 2009 as a Rate Analyst Specialist. In 2011, I was promoted to Senior Rate Analyst; promoted to Supervisor in 2015; and in 2018, I was promoted to my current position.

In addition to my professional experience and education, I have attended professional development seminars sponsored by National Economic Research Associates (also known as NERA Economic Consulting, Inc.), Electric Utility Consultants Inc., The Brattle Group, NMSU's Center for Public Utilities, American Gas Association, Edison Electric Institute, Association of Edison Illuminating Companies, the Financial Accounting Institute, and American Water Works Association.

Q4. PLEASE DESCRIBE YOUR CURRENT RESPONSIBILITIES WITH EPE.

A. As Manager of Rate Research, my responsibility is to provide oversight of the preparation of economic, statistical, cost and rate design studies; development of models and methodologies for cost-of-service, profitability and pricing studies; tariff development and administration; and the execution of annualization and revenue forecasts.

Q5. HAVE YOU PREVIOUSLY PRESENTED TESTIMONY BEFORE UTILITY REGULATORY BODIES?

A. Yes, I have previously filed testimony with and testified before the Public Utility Commission of Texas ("PUCT" or "Commission") and the New Mexico Public Regulation Commission.

II. Purpose of Testimony

Q6. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. My testimony presents the process EPE undertook to determine the proposed final class revenue allocation, as supported by the Class Cost-of-Service ("CCOS") study. My testimony describes EPE's rate design based on this base revenue allocation for all rate classes and an evaluation of the impact of EPE's rate proposals on customers. I discuss EPE's proposals to revise the terms of service for rate schedules, including the implementation of the new fuel adjustment factor rate schedule. Finally, I present EPE’s request to implement a Peak Time Rebate Pilot Program and provide an example of proposed capacity reservation charges under the Company’s line extension policy.

Q7. ARE YOU SPONSORING ANY EXHIBITS IN YOUR TESTIMONY?

A. Yes. I am sponsoring the exhibits listed in the Table of Contents page and which are attached to this testimony.

Q8. WHAT SCHEDULES DO YOU SPONSOR OR CO-SPONSOR?

A. Exhibit MC-1 lists the required PUCT's Electric Utility Rate-Filing Package for Generating Utilities ("RFP") schedules I sponsor.

Q9. WERE THE RFP SCHEDULES AND EXHIBITS YOU ARE SPONSORING PREPARED BY YOU OR UNDER YOUR DIRECT SUPERVISION?

A. Yes, they were.

III. Proposed Base Revenue Allocation by Rate Class

Q10. WHAT IS EPE'S TOTAL SYSTEM AVERAGE BASE REVENUE INCREASE PROPOSED IN THIS CASE?

A. As detailed in the Direct Testimony of EPE witness Adrian Hernandez, and as shown in RFP Schedule A-1, EPE's Texas jurisdiction revenue deficiency is $84.7 million. This equates to a proposed total base-rate revenue increase, including non-firm revenues, of $85.7 million[1] or a base-rate revenue increase (i.e., system average increase) of 13.649%[2] and a proposed $1 million reduction in miscellaneous service charges.

Q11. DOES EPE INTEND TO LIMIT THE RATE CLASS IMPACT OF ITS PROPOSED BASE REVENUE INCREASE?

A. No. As addressed in the Direct Testimony of EPE witness George Novela, EPE is proposing to move all rate classes to full cost, as indicated by EPE's CCOS.

Q12. WHAT IS EPE'S PROPOSED BASE REVENUE INCREASE BY RATE CLASS?

A. Table MC-1 below summarizes the base revenue allocation by rate class at full cost of service. The full cost of service amounts of each rate class presented in the table are the targeted revenue for the rate design process.

[1] EPE is proposing a non-firm base rate revenue increase at the system average or $483,770 and the base-rate revenue increase from the rate classes, net of the non-firm base-rate revenue increase, is $85,181,944; summing to a total base rate increase of $85,665,713.

[2] The system average increase is 13.649% ($85,665,713 total base-rate increase / $627,629,349 adjusted total base-rate revenue at existing rates).

Table MC- 1

Rate	Firm Rate Class	Base Rate Revenue @ Present Rates	Full Cost of Service *	Full Cost % Revenue Increase	Full Cost $ Revenue Increase
01	Residential Service	$ 316,191,801	$ 395,261,738	25.007%	$ 79,069,937
02	Small General Service	49,947,843	51,778,536	3.665%	1,830,692
07	Outdoor Recreational Lighting	883,319	896,291	1.469%	12,973
08	Government Street Lighting	4,338,206	3,539,674	-18.407%	(798,533)
09	Traffic Signals	104,089	102,142	-1.871%	(1,947)
11	Municipal Pumping	10,307,541	10,404,842	0.944%	97,301
15	Electrolytic Refining Service	2,017,580	2,468,863	22.368%	451,283
22	Irrigation Service	395,112	395,912	0.202%	800
24	General Service	139,514,005	135,159,886	-3.121%	(4,354,119)
25	Large Power Service	40,533,991	45,271,148	11.687%	4,737,157
26	Petroleum Refinery Service	16,483,616	17,326,762	5.115%	843,146
28	Area Lighting Service	2,823,722	3,372,890	19.448%	549,168
30	Electric Furnace Rate	1,357,275	1,793,578	32.146%	436,303
31	Military Reservation Service	14,899,010	16,255,306	9.103%	1,356,296
34	Cotton Gin Service	141,513	138,920	-1.833%	(2,593)
41	City and County Service	23,644,914	24,559,429	3.868%	914,514
WH	Water Heating Service	501,476	541,043	7.890%	39,567
Total		$ 624,085,014	$ 709,266,958	13.649%	$ 85,181,944

* Net of $483,770 increase to Non-Firm Revenue from $3,544,335 to $4,028,104.

Q13. PLEASE EXPLAIN THE DIFFERENCE BETWEEN THE FULL COST $ REVENUE INCREASE IN TABLE MC-1 AND THE BASE REVENUE DEFICIENCY IN TABLE 5 IN EPE WITNESS HERNANDEZ'S TESTIMONY.

A. As indicated by the footnote to Table MC-1, the full cost of service amounts of each rate class is net of the increase to non-firm revenue, i.e., that increase has been allocated to each class. This allocation is done because non-firm revenue, Rate Schedule No. 38, is not considered a rate class in EPE cost of service studies, but rather as a revenue credit which is allocated to each firm rate class.

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IV. Proposed Rate Design

A. Overview

Q14. WHAT ARE THE PRIMARY GOALS EPE SEEKS TO ACHIEVE WITH THE PROPOSED RATE DESIGN PRESENTED IN THIS CASE?

A. EPE seeks to achieve a variety of goals through its proposed rate design. These goals for rate design include the following, in no order of significance:

- Minimizing subsidies within rate classes and sending accurate price signals by ensuring classification component costs (i.e., demand, energy, and customer costs) are recovered consistently with how these costs are incurred;
- Ensuring rate structures are supported by cost causation principles and, to the extent possible, encourage energy conservation and potentially reduce contributions to EPE's system peak demand;
- Providing stable rates for customers; and
- Promoting stability of revenues to allow EPE the opportunity to recover its costs of providing safe and reliable service to Texas customers.

Q15. HOW DOES THE COMPANY PROPOSE TO MINIMIZE SUBSIDIES WITHIN EACH RATE CLASS?

A. Subsidies within a rate class occur when the components of the rates charged do not adequately reflect the underlying costs to serve. EPE proposes to minimize intra-rate class subsidies, to the extent possible, by ensuring that the proposed rates adequately recover each classification component cost in a manner that appropriately reflects their cost causation. Recovering costs based on factors that reasonably reflect their cost causation results in price efficiency and reduces the potential that some customers within a rate class will subsidize other customers within the same rate class.

Q16. ARE THERE CHANGES PROPOSED BY EPE DESIGNED TO ADDRESS THE INTRA-RATE CLASS SUBSIDIZATION THAT IS COMMON ACROSS RATE CLASSES?

A. Yes. The Company is proposing to move the monthly customer charges closer to the full cost of service and in some cases to fully recover all the customer-related costs identified in the CCOS from the customer charges. Increasing the customer charge to full cost of service, where possible, reduces intra-rate class subsidies and improves the accuracy of the price signal provided by the volumetric energy charge.

Similarly, the Company proposes to set demand charges to reflect the costs of providing the associated electric service more accurately. For all rate classes with demand charges, EPE is proposing demand charges closer to the full cost of service and in some cases to fully recover all the demand-related costs identified in the CCOS from the demand charges. Therefore, aligning the monthly customer and demand charges with their underlying costs reduces intra-rate class subsidies and improves the accuracy of the price signals.

Q17. IS EPE PROPOSING RATE STRUCTURES THAT ENCOURAGE ENERGY CONSERVATION AND POTENTIALLY REDUCE CUSTOMERS' CONTRIBUTION TO EPE'S SYSTEM PEAK?

A. Yes. Accurate price signals convey to customers the cost differences between seasonal and non-seasonal time periods. This allows customers to make economic decisions, promote energy conservation, and encourage customers to shift usage from peak periods to off-peak periods. EPE's proposed changes to demand, and energy charges are intended to produce more accurate price signals that communicate those price differentials to customers, particularly during summer months. EPE is proposing to set demand charges to collect demand-related costs in both the summer and the non-summer months by assigning demand-related costs to seasonal periods as a function of the system loads. For those rate classes with a time variant pricing structure, energy charges are developed with on-peak period energy price differentials that reflect the incremental generation costs, which has the incentivizing effect of reducing contributions to EPE's system peak. Finally, EPE proposes to remove any declining-block energy rate structures that do not have a cost justification, which otherwise do not support energy efficiency and conservation.

Q18. DO EPE'S PROPOSED RATES ENHANCE RATE STABILITY FOR CUSTOMERS?

A. Yes. Because EPE's costs of service and cost responsibility by rate class generally do not vary widely from year-to-year, cost-based rates should be similarly stable, avoiding significant rate volatility for customers. Rates that more closely follow their underlying cost, which would thus provide customers with more accurate price signals, would normally allow customers to reasonably anticipate what their electric bills will be and make economic decisions regarding their electric consumption.

Q19. DO THE PROPOSED RATES PROMOTE STABILITY OF REVENUES FOR EPE?

A. Yes. The proposed rates link revenues more closely to costs, thereby ensuring that the costs are reasonably matched with revenues. That is, by sending customers more accurate price signals, EPE anticipates that future cost increases (or decreases) will better track future revenue increases (or decreases). In addition, EPE's proposed rates attempt to provide a better recovery of fixed costs (i.e., costs that do not vary with the amount of kWh) through more accurate customer and demand charges.

Q20. HOW DO THE PROPOSED RATES PROVIDE EPE WITH AN OPPORTUNITY TO RECOVER ITS COSTS?

A. As demonstrated by RFP Schedule Q-7, Proof of Revenues, the proposed rates are designed to recover EPE's proposed revenue requirement in this case. The Test Year billing determinants employed in developing rates have been adjusted as discussed in EPE witness Rene Gonzalez's direct testimony and accurately reflect the way customers will be billed once the proposed rates go into effect.

Q21. HOW HAS EPE EMPLOYED THE RESULTS OF ITS CLASS COST-OF-SERVICE STUDY IN ITS PROPOSED RATES?

A. EPE has proposed a number of changes to its rates that are necessary to better reflect the costs of providing service, particularly in determining the individual rate components: customer, demand, and energy charges. EPE's proposed changes to these charges, contained in its proposed tariffs, were developed to more accurately reflect the customer, demand, and energy classification component unit costs calculated for each rate class, as provided in the cost-of-service schedule, RFP Schedule P-6.

Q22. WHAT RATES OR RATE CHANGES IS EPE PROPOSING IN THIS CASE TO

IMPROVE ACCURATE PRICE SIGNALS?

A. The Company is proposing a variety of rate structure modifications that will provide more accurate price signals to customers. These proposed modifications include:

- Moving customer charges to full cost of service, collecting all the customer-related costs in the customer charge.
- Aligning the recovery of demand-related costs with demand charges while limiting seasonal demand charges to collect no more than 100% of the demand-related costs.
- Modifying the summer on-peak period and off-peak period price differentials for TOD rates to reflect EPE's incremental capacity cost and provide more effective incentives to consumers to shift load or reduce peak consumption during the entire summer period.

Q23. DESCRIBE EPE'S GENERAL PROCESS TO DESIGN ITS PROPOSED BASE RATES IN THIS CASE?

A. Although rates can be theoretically developed following any sequence with respect to the different cost elements, EPE chose to start the rate design process with the determination of the customer charge for each rate class. As a general principle, EPE targeted a customer charge that would allow for the recovery of 100% of the customer-related costs for each rate class.

Next, if applicable, EPE proceeded to the design of the demand charges, using EPE's incremental capacity cost, for most rate classes, to recognize seasonal cost differences for generation costs. EPE limited its proposed seasonal demand charges so that demand charges will not collect more than 100% of the demand-related costs as indicated by the CCOS study.

Lastly, EPE designed the volumetric rates for both non-TOD and TOD service, either for mandatory rates or optional rates when applicable. In general, volumetric rates were designed to provide a more homogenous seasonal pricing among rate classes, while at the same time using marginal costing information to determine a reasonable peak-to-off-peak price ratio that would reflect the incremental capacity costs in the summer on-peak period rates. The volumetric rates were the "catch-all" price category that would include any costs not recovered through the customer- or demand-related components, to arrive at the total revenue requirement by rate class as proposed by EPE in this case.

Q24. HAS EPE INCORPORATED ANALYSES OR FINDINGS FROM THE BRATTLE REPORT INTO ITS PROPOSED RATE DESIGN IN THIS PROCEEDING?

A. Yes. Namely, the proposal to shift the on-peak period of the time varying rate structure is based on the analyses prepared for the Brattle report. The on-peak period shift is described further in this testimony.

Q25. PLEASE EXPLAIN WHAT THIS BRATTLE REPORT IS.

A. EPE contracted with The Brattle Group ("Brattle") in 2023 to design EPE's time varying rate ("TVR") pilot program, which was filed in Docket No. 56658.[3] More specifically, Brattle assessed and screened alternative rates to be tested in the pilot, assisted EPE with the design of alternative rates to be tested in the pilot, and assessed the bill impacts of the proposed TVRs. The result was Brattle's report titled *El Paso Electric Texas Time-Varying Rate Pilot Design*. Only customers that take service under Rate Schedule No. 01 and Rate Schedule No. 02 can participate under this pilot program.

Q26. OVERALL, WHAT IS THE END RESULT OF EPE'S PROPOSED CHANGES TO ITS CURRENT RATE STRUCTURES?

A. All the proposed changes to EPE's current rate structures mentioned above will provide customers with an improved pricing structure that better reflects the differences and variations in electricity costs throughout the year and, therefore, the rate structures provide more accurate and effective price signals. The changes to EPE's rate structures proposed in this case will allow customers to make economic decisions about their electric usage based on rates that more accurately reflect the underlying costs and that will provide economic incentives to conserve energy and potentially improve the utilization of EPE's electric grid by increasing the overall system load factor.

Q27. HAS EPE PREPARED COMPARISONS OF CURRENT AND PROPOSED RATES AND IMPACTS ON CUSTOMERS?

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[3] *Application of El Paso Electric Company's Approval to Implement a Time-Varying Rate Pilot Program*, Docket No. 56658, Filed May 24, 2024.

A. Yes. Exhibit MC-3 compares, by rate component, the proposed base rates to current base rates for each rate class and shows the percentage changes to those rates.

Q28. IN ADDITION TO REVISING THE APPLICABLE BASE RATES, IS EPE PROPOSING ANY OTHER CHANGES TO ITS RETAIL RATE SCHEDULES IN THIS RATE CASE?

A. Yes. EPE is proposing language revisions to multiple rate schedules. A more detailed discussion about these changes is provided in RFP Schedule Q-4.2 and discussed in the following sections of this testimony.

B. Customer Charges

Q29. WHAT IS EPE'S RATIONALE TO PROPOSE THE FULL RECOVERY OF CUSTOMER-RELATED COSTS THROUGH CUSTOMER CHARGES FOR SOME RATE CLASSES?

A. As explained above, this proposal is intended to mitigate intra-rate class subsidization and provide all customers with better price signals. For example, if a significant portion of fixed costs are recovered through volumetric energy charges, that is, costs that do not vary with the amount of energy or kWh used such as customer-related costs, customers who reduce their usage avoid paying the fixed costs incurred to provide service to them. Unless costs are recovered through appropriate fixed charges and variable energy charges, other customers in the class bear the portion of the fixed costs avoided by customers who install energy efficiency measures, purchase distributed renewable generation, or otherwise reduce their energy consumption.

Customer-related costs are associated with maintaining the customer on the EPE system and can be characterized generally as costs related to the metering, billing, and customer service functions. The important characteristic here is that these costs do not vary based on the customer's energy consumption.

Q30. DOES INCREASING THE CUSTOMER CHARGES MEAN THAT EPE WILL BE ABLE TO RECOVER ALL OF ITS FIXED COSTS ALLOCATED TO RATE CLASSES?

A. No. Several rates, such as the Residential Service rates, use a fixed monthly customer charge and volumetric rates per kWh of electricity used to recover all other fixed costs (also known as a two-part tariff) including generation, transmission, and distribution system costs.

Q31. WHY IS IT IMPORTANT TO ESTABLISH CUSTOMER CHARGES THAT ARE COST-BASED OR THAT MOVE CLOSER TOWARDS COST-BASED LEVELS FOR ALL RATE CLASSES?

A. Increasing the customer charges to full cost of service, where possible, reduces intra-rate class subsidies and improves the accuracy of the price signal provided by other charges, particularly the volumetric energy charge. Intra-rate class subsidization for customer-related costs can occur when the customer charge does not reflect 100% of the costs. That is because any customer-related costs not recovered through the customer charge are normally recovered from the volumetric rates. Thus, everything else being equal, higher-than-average usage customers would pay an amount higher than the cost-based level towards customer-related costs; lower-than-average usage customers, would pay an amount less than the cost-based level towards customer-related costs, creating the intra-rate class subsidy referenced above. The higher-than-average usage customer would be subsidizing the lower-than-average usage customer with regard to customer-related costs.

Q32. IN YOUR OPINION, WILL EPE'S PROPOSED INCREASES TO CUSTOMER CHARGES HAVE A LARGE BILL IMPACT ON CUSTOMERS?

A. Not likely. Customer charges typically compose a small percentage of any rate class's average bills.

C. Demand Charges

Q33. WHAT IS EPE'S RATIONALE FOR THE RECOVERY OF DEMAND-RELATED COSTS FROM DEMAND CHARGES?

A. EPE's goal in determining demand charges is to propose charges that align cost causation with cost recovery, that is, demand charges that more closely reflect all the underlying demand-related costs, such as those associated with the generation, transmission, substations, primary, and secondary distribution systems. Furthermore, in setting demand charges, EPE is also taking into consideration the seasonal bill impacts of those changes to demand charges in the affected rate classes, especially for customers with different load factors and seasonal usage within each rate class. Therefore, EPE's proposed demand charges to collect different amounts of demand-related costs by rate class balance the stated goal of aligning cost with rates and the potential seasonal bill impacts within each rate class under a three-part tariff (i.e., with customer, demand, and energy charges).

In other non-residential rate classes, these types of costs are generally recovered through a demand charge applied to the billed kW or maximum load drawn by customers in any given month. Because electric systems are built and sized to meet the electric needs of customers at every point in time, including periods when electricity demand reaches its maximum, demand charges allow utilities to recover these fixed costs through a rate element that more accurately reflects the way these costs are incurred to meet the customers' instantaneous demand. In EPE's rate structures, these demand charges are determined based on the customer's highest level of electric usage at any given moment during each billing period, a demand ratchet based on the customer's load during the summer months, or a minimum demand specified in the rate schedule.

Q34. WHY IS EPE PROPOSING TO CHARGE HIGHER DEMAND CHARGE RATES DURING THE SUMMER PERIOD WHEN COMPARED TO NON-SUMMER PERIOD?

A. A higher demand charge rate during the summer period will provide customers with a better price signal by recognizing the higher loads experienced during the summer months. Also, assessing a moderately higher price during all the summer months could encourage customers to invest in energy efficiency and conservation targeting summer usage and obtain a faster payback on their investment, while helping reduce the peak loads experienced in the summer season, which is normally the time of the year when continued growth in demand may trigger the need for additional generation capacity.

D. Non-TOD Energy Charges

Q35. WHAT FUNDAMENTAL APPROACH DID EPE TAKE IN CALCULATING THE

NON-TOD ENERGY CHARGES?

A. EPE's approach in calculating the non-TOD energy charges was to ensure that those charges provide a strong pricing signal toward conservation during the summer months. Another potential consequence of this stronger pricing signal is to reduce the loads that have contributed to EPE's declining load factor. EPE witness Enedina Soto addresses the declining load factor in her direct testimony.

Q36. DO EPE'S CURRENT NON-TOD ENERGY CHARGE STRUCTURES ALREADY PROVIDE THIS CONSERVATION PRICING SIGNAL?

A. Most of them do. However, the energy charge rate structures of Rate Schedule Nos. 24 and 41 are in the form of a declining-block structure. This means that the average price declines as energy consumption increases. Rate Schedule No. 41's current rate structure exhibits this average price decline most profoundly and militates against achieving energy efficiency and conservation goals.

E. Time-of-Day (TOD) On-Peak Period Hours

Q37. IS EPE PROPOSING TO CHANGE THE ON-PEAK PERIOD HOURS FOR TOD RATES TO ALIGN WITH THE HOURS THAT EPE'S SYSTEM EXPERIENCES IT HIGHEST LOADS?

A. Yes. Informed by EPE's system cost profiles, the Brattle report shows that the highest cost hours fall between 2:00 P.M. and 7:00 PM, which warrants a change in the on-peak period applicable to TOD tariffs and rate options. Currently, in most of EPE's rate schedules with a TOD rate structure, the on-peak period hours are defined from noon to 6:00 PM.

RFP Schedules Q-8.03 and Q-8.04, filed in this proceeding, support the Brattle report's determination of the 5-hour on-peak period. Specifically, the values shown for the summer season weekday corroborate the findings in the Brattle report. Therefore, EPE is proposing to change the on-peak period hours of its TOD rates to that 5-hour on-peak period.

Q38. HOW MANY ANNUAL HOURS DOES THE PROPOSED 5-HOUR ON-PEAK PERIOD TARGET WITH THE HIGHER PRICED ENERGY CHARGE?

A. The proposed 5-hour on-peak period of 2:00 P.M. through 7:00 PM amounts to 430 annual hours (or 4.9% of total hours in the Test Year). RFP Schedules Q-8.02, which provides annual load duration curves, shows that that on-peak period will target approximately 475 megawatts ("MW") of load for reduction.

F. TOD Energy Charges

Q39. HOW WERE THE ON-PEAK PERIOD AND OFF-PEAK PERIOD ENERGY CHARGES CALCULATED?

A. The on-peak period energy price adder, which is the incremental charge for consumption during the on-peak period hours, was designed to recover a percentage of EPE's incremental capacity cost of $134.02 per kW-year. This amount was divided by the average consumption for the rate class during the proposed on-peak period hours to derive the on-peak period energy price adder per kWh. The on-peak period energy price adder is added to the Off-Peak Period Energy Charge to produce the On-Peak Period Energy Charge. The percentage of total incremental capacity cost to recover in the on-peak period differs by rate class. The Off-Peak Period Energy charge per kWh was calculated to recover the remaining cost that is not recovered through the Customer, Demand, and On-Peak Period Energy Charges and is applicable during all other hours of the year.

Q40. HOW DID EPE DETERMINE THE INCREMENTAL CAPACITY COST OF $134.02 PER KW-YEAR?

A. In EPE's last rate cases in Texas and New Mexico, EPE relied on the costs for the Rio Grande Unit 9 combustion turbine to estimate the incremental capacity cost used in rate design, and thus, EPE used that unit's most recent levelized costs in this base rate case filing for consistency purposes. This is consistent with the electric utility industry where the cost of a combustion turbine has been used as a proxy for the marginal generation costs. Development of the incremental capacity cost is shown in Workpaper Q-7(a).

Q41. PLEASE EXPLAIN WHY THE ON-PEAK PERIOD ENERGY PRICE ADDER IS BASED ON PERCENTAGES OF THE INCREMENTAL CAPACITY COST THAT DIFFER BY RATE CLASS.

A. The percentages of EPE's incremental capacity cost by rate class on which the TOD On-peak period energy price adders are based are a part of EPE's tools in its rate design process. In balancing gradualism, as well as developing On-Peak Period Energy Charges with the intent to influence certain consumption behaviors, it is necessary that the percentages differ among rate classes. If the percentages are set too high, rate shock is introduced while setting percentages too low, has the unintended effect of the On-peak period charges being insufficient. The On-peak energy price adders by rate class, along with the percentages can be found in EPE's rate design model, Workpaper Q-7(a).

Q42. SHOULD EPE USE MORE RECENTLY CONSTRUCTED GENERATION UNITS TO SET THE INCREMENTAL CAPACITY COST USED IN ITS RATE DESIGN?

A. As discussed previously, the On-peak energy price adder represents a percentage of EPE's incremental capacity cost. In the rate design of most TOD rates, that percentage is set at far below 100%. When that percentage begins approximating 100% in a future rate case, EPE will reevaluate which unit or units to consider as the incremental capacity cost.

Q43. WHAT IS EPE'S APPROACH TO CALCULATE THE OPTIONAL TOD RATES?

A. The optional TOD rates were designed to be revenue neutral relative to the annual charges under the standard service rate. This approach will result in the annual rate class base-rate revenue to be the similar amount whether all customers in the rate class choose to take service under the standard rate or under the TOD rate.[4] Revenue neutrality results from comparing the total "annual" non-fuel revenue allocated to the rate class, either for the standard or the optional TOD rate designs. More importantly, the revenue neutrality between the standard and optional TOD rates applies to the "average" annual bill and not to each month or season.

V. Rate Schedule Revisions

Q44. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?

A. In this section of my testimony, I discuss the more significant revisions to EPE's existing

[4] Although the approach is to make the revenues "neutral" between standard and optional rate options, due to rounding, the amounts will not necessarily be equal.

rate schedules that are proposed in this proceeding. Discussion about changes to each rate schedules is also provided in RFP Schedule Q-4.2.

Q45. IN ADDITION TO REVISING THE APPLICABLE BASE RATES AND STRUCTURES, IS EPE PROPOSING ANY OTHER SIGNIFICANT CHANGES TO ITS RETAIL RATE SCHEDULES IN THIS RATE CASE?

A. Yes. EPE is proposing language changes to clarify and improve the structure of the rate schedules.

Q46. ARE THERE ANY SIGNIFICANT LANGUAGE CHANGES APPLICABLE TO ALL OR MOST PROPOSED RATE SCHEDULES?

A. Yes, there are four significant language changes. First, as discussed previously, the On-peak period of nearly all of EPE's TOD rates and rate option is redefined to a five-hour period from 2:00 P.M. through 7:00 P.M.

Secondly, the bill protection provision in several rate schedules is changed to describe an all-encompassing limitation on the number of customers that can receive such bill protection. EPE's experience with current bill protection provision proved to be administratively burdensome and is therefore proposing to set a monthly aggregate limit of the first 100 new customers to enroll in the Alternative TOD Rate option of any rate schedule. In other words, the total of new TOD rate customers in all rate schedules that will get the bill protection is limited to the first 100 new customers of each month. This will help ensure the Company has the resources available to timely prepare the analyses for each new TOD rate option customer twelve months later and that the proper modifications are made in its billing system for any customer that opts to revert to the Standard Rate.

The third language change is applicable to several rate schedules that include a primary voltage rate. EPE witness Chagnon testifies that one or more EPE customers with significant load have requested an additional service primary voltage feed and related distribution facilities as a back-up to their initial service feed facilities to ensure a continuous supply of power (i.e., back-up feeder), effectively reserving capacity on EPE's distribution system and limiting access to that capacity to other potential customers. To avoid other customers from subsidizing the costs of such requests, EPE is proposing to implement a Reserved Distribution Capacity Service Charge which will be billed to customers that make such new requests. Customers will be required to enter into an agreement with the Company by which a contracted amount of reserved capacity, in kW, will be identified and continue to be billed until such time that the customer no longer requires a back-up feeder. The Reserved Distribution Capacity Service Charge rate is the same as the primary voltage Demand Charge, under the applicable rate option that the backed-up service is billed under.

The fourth language change applicable to all or most of the proposed rate schedules, i.e., replacing a reference to the Rate Schedule No. 98 Fixed Fuel Factor with a reference to the retitling of it to "Fuel Adjustment Factor".

I refer to these four language changes as the "broadly applicable language changes" later in my testimony.

Q47. HAVE YOU PROVIDED COPIES OF THE PROPOSED RATE SCHEDULES?

A. Yes. EPE's proposed rate schedules are presented in RFP Schedule Q-8.8.

Q48. WHEN WERE EPE'S CURRENTLY EFFECTIVE RATE SCHEDULES APPROVED AND IMPLEMENTED?

A. EPE's currently effective rate schedules were approved in PUCT's Final Order in Docket No. 52195 ("2021 Rate Case") on September 15, 2022. They became effective November 3, 2021, but were implemented for billing on August 1, 2022.

A. Schedule No. 01 – Residential Service

Q49. PLEASE DESCRIBE THE EXISTING RATE SCHEDULE NO. 01 – RESIDENTIAL SERVICE RATE SCHEDULE.

A. This rate schedule is applicable to single-family residences or individually metered apartments for primarily domestic or home use. The rate schedule includes three monthly rate options: a Standard Service Rate, an Alternative Time-Of-Day ("TOD") Rate, and Demand Charge TOD Rate. A clause is included that offers bill protection to the first 500 customers that elect to take service under the Alternative TOD Rate for an initial twelve-month period under that rate option.

The rate schedule also includes a provision for a monthly minimum charge, including special charges applicable to distributed generation ("DG") customers. It includes reference to other applicable riders, as well as terms and conditions that apply to service under this schedule. Other provisions currently offered under the rate schedule include an Off-Peak Water Heating Rider, which is closed to new service applications, and a Low-Income Rider.

Q50. PLEASE DESCRIBE THE EXISTING STRUCTURE OF RATES OFFERED UNDER RATE SCHEDULE NO. 01.

A. The Standard Service Rate structure consists of a monthly Customer Charge and seasonal, inclining two-block Energy Charges. The inclining block rate structure applies in the six months of May through October. The first block of the summer Energy Charge includes slightly more than a one cent per kWh price differential over the non-summer Energy Charge. The second block of the summer Energy Charge includes slightly more than a half cent per kWh price differential over the first block. The non-summer Energy Charge is applied to all usage in the months of November through April.

The Alternative TOD Rate consists of a monthly Customer Charge and Energy Charges that apply based on the month, day, and hour that usage occurs. The On-Peak Period Energy Charge applies from noon to 6:00 P.M. Mountain Daylight Time (in all rate schedules, all times listed are Mountain Daylight Time), weekdays during the summer period, and the Off-Peak Period Energy Charge applies during all other hours. Like EPE's other TOD rates, the summer period is defined as June through September.

The Demand Charge TOD Rate consists of a monthly Customer Charge, a flat Demand Charge, and Energy Charges that apply based on the month, day, and hour that usage occurs. The On-Peak Period Energy Charge applies from noon to 6:00 P.M., weekdays during the summer period, the Off-Peak Period Energy Charge applies during all other hours.

Q51. OTHER THAN THE BROADLY APPLICABLE LANGUAGE CHANGES, WHAT OTHER SIGNIFICANT LANGUAGE CHANGES ARE PROPOSED FOR RATE

SCHEDULE NO. 01?

A. The summer period definition of the Standard Service Rate is changed from six months to four months, June through September, to be consistent with EPE's other rate schedules that contain seasonal price differentials. Also, the two minimum bill amounts applicable to DG customers are deleted because EPE is proposing for all DG customers that do not meet the grandfathering clause to take service under the new proposed Distributed Generation Rate described below. No other significant language changes are proposed for this rate schedule.

Q52. WHAT CHANGES DOES EPE PROPOSE FOR THE RATE SCHEDULE NO. 01 RATES AND RATE STRUCTURES?

A. For the Standard Service Rate, EPE is proposing to:

(1) set the monthly Customer Charge to collect all the customer-related costs;

(2) increase the price differential between summer and non-summer Energy Charges; and

(3) to the extent possible, increase the price differential between the first and second blocks of the summer Energy Charges.

For the Alternative TOD Rate, EPE is proposing to:

(1) set the monthly Customer Charge equal to the Standard Service Rate Monthly Customer Charge;

(2) set the non-summer Off-Peak Period Energy Charge equal to the Standard Service Rate non-summer Energy Charge; and

(3) to the extent possible, increase the price differential between On-Peak Period and Off-Peak Period summer Energy Charges.

For the Demand Charge TOD Rate, EPE is proposing to:

(1) set the monthly Customer Charge equal to the Standard Service Rate Monthly Customer Charge;

(2) set the Demand Charge to fully reflect distribution-related costs;

(3) set the non-summer Off-Peak Period Energy Charge equal to the Standard Service Rate non-summer Energy Charge, less an amount commensurate to the distribution-related costs recovered through the Demand Charge; and

(4) to the extent possible, increase the price differential between On-Peak Period and

Off-Peak Period summer Energy Charges.

For the new Distributed Generation Rate, EPE is proposing to:

(1) set the monthly Customer Charge equal to the Standard Service Rate Monthly Customer Charge;

(2) set the Demand Charge to reflect the distribution demand-related cost, at full-cost, plus a ten percent (10 percent) adder for the demand-related components of transmission and production demand-related cost; and

(3) set the Energy Charge equal to the Standard Service Rate Energy Charge, less an amount commensurate to the demand-related costs recovered through the Demand Charge.

Exhibit MC-3 provides a comparison of current and proposed rate components for each of the rate options of all the proposed rate schedules.

Q53. WHY IS EPE PROPOSING TO INCREASE THE CUSTOMER CHARGE FOR THE RESIDENTIAL SERVICE RATE?

A. As noted previously, charges that reflect the cost of providing service communicate accurate price signals to customers. Therefore, EPE is proposing to increase the monthly Customer Charge for Residential Service from $9.25 to $13.71 to reflect the customer-related costs determined by its cost-of-service study more accurately. These are costs that are associated with maintaining the customer on EPE's system and can be characterized generally as costs related to the metering and billing functions, and to providing customer service. The important characteristic here is that these costs do not vary as a function of the energy consumption of the customers.

Q54. HOW DOES EPE'S CURRENT AND PROPOSED CUSTOMER CHARGE FOR THE RESIDENTIAL SERVICE RATE NO. 01 COMPARE TO OTHER NON-ERCOT INVESTOR-OWNED UTILITIES IN TEXAS?

A EPE's current residential Customer Charge is $9.25 per meter/month for the Standard Service Rate option and proposed at $13.71. EPE's current charge is currently the lowest among non-ERCOT, investor-owned electric utilities in Texas, when compared to

Entergy's $14.00,[5] Southwestern Electric Power Company's $9.42,[6] and Xcel Energy Texas' (or Southwestern Public Service) $12.45.[7] Therefore, EPE's proposed cost-based Customer Charge for Rate Schedule No. 01 is within a zone of reasonableness when compared to the monthly charges for residential electric service of EPE's peer traditional vertically-integrated non-ERCOT utilities.

Q55. WHY IS EPE PROPOSING TO SHORTEN THE SUMMER PERIOD OF THE STANDARD SERVICE RATE?

A. The summer period of the Rate Schedule No. 01 Standard Service Rate is the only one of all EPE's rate schedules defined as May through October. EPE's proposal to reduce the number of months included in the summer season, June through September, aligns all pricing structures offered in Texas with EPE's summer period and system peak hours. Doing so provides a stronger price signal during times when EPE's system experiences its peak demand. A four-month summer period for billing purposes will also align with the time period that supports the allocators used for the assignment of generation and transmission costs to rate classes as explained in more detail in the Direct Testimony of EPE witness Hernandez. Having a shorter, more uniform and clearly defined "peak" summer season, applied consistently across most rate classes, will convey to customers more transparent and stronger price signals.

Q56. WHY IS EPE PROPOSING TO INCREASE THE PRICE DIFFERENTIAL BETWEEN SUMMER AND NON-SUMMER ENERGY CHARGES?

A. As noted previously, EPE is proposing rate structures that encourage energy conservation and potentially reduce customers' contribution to EPE's system peak. Seasonal Energy Charges are useful to send pricing signals that communicate the higher production and transmission-related operating costs that have been incurred by EPE to meet the summer

[5] Schedule RS, Residential Service, effective on and after 12-3-2022. Accessed on December 30, 2024, at https://cdn.entergy-exas.com/userfiles/content/price/tariffs/eti_rs.pdf?_ga=2.260254093.1427452262.1620243496-1085871750.1598978337.

[6] Schedule Residential Service (RS), effective for service on March 1, 2022. Accessed on December 30, 2024, at https://www.swepco.com/lib/docs/ratesandtariffs/Texas/TexasRatesChargesandFees09-27-2024.pdf.

[7] Residential Service, effective for service on January 23, 2024. Accessed on December 30, 2024 at https://www.xcelenergy.com/staticfiles/xe-responsive/Company/Rates%20&%20Regulations/TV-3.%20Rev.%2023%20-%20Residential%20Service%20D54634%20(2-1-24).pdf.

months loads. The price differential between the Standard Service Rate summer first block and the non-summer Energy Charge is proposed to increase to two cents from the current slightly more than one cent differential to provide a stronger price signal for the proposed four-month summer season.

Q57. WHY IS EPE PROPOSING TO INCREASE THE PRICE DIFFERENTIAL BETWEEN THE FIRST AND SECOND BLOCKS OF THE STANDARD SERVICE SUMMER ENERGY CHARGES?

A. Like the purpose of seasonal Energy Charges, the intent of an inclining-block structure is to encourage energy conservation and potentially reduce customers' contribution to EPE's system peak. The price differential between the first and second block of the Standard Service Rate Summer Energy Charge is proposed to increase to a full cent from the current slightly more than half cent differential.

Q58. HAS THE COMPANY ADJUSTED BILLING DETERMINANTS FOR ENERGY CONSERVATION AND POTENTIAL REDUCTION IN THE CUSTOMERS' CONTRIBUTION TO EPE'S SYSTEM PEAK AS A RESULT OF THE INCREASED PRICE DIFFERENTIALS?

A. No. Although the increase in the price differentials is expected to result in customers modifying their consumption behavior, price elasticity data specific to EPE is not available to make any reasonable estimation of an adjustment to billing determinants of any rate.

Q59. HAS THE COMPANY ANALYZED THE IMPACT OF THE PROPOSED STANDARD SERVICE RATES ON RESIDENTIAL SERVICE CUSTOMERS WITH VARIOUS USAGE CHARACTERISTICS?

A. Yes. RFP Schedule Q-8.9 provides bill impacts based on various levels of electric usage. The monthly bill impact of the higher Customer Charge and the increase to the Energy Charge in the summer months is mitigated to some extent by EPE's proposed change in the summer period. The proposed change provides a lower Energy Charge for kWh consumption in non-summer months over an eight-month period instead of the current six-month period. This change results in an appropriately higher rate for energy consumption for higher use in the summer, the period when EPE experiences its system peak load and when growth in peak demand over time requires additional capacity. The combined result of the summer period and rate change is that billed charges more accurately reflect the cost of providing service across the Residential rate class.

Q60. WHAT IS THE IMPACT OF THIS RATE STRUCTURE ON LOW INCOME RIDER CUSTOMERS?

A. EPE's existing Low-Income Rider under Rate Schedule No. 01 provides for a waiver of the monthly Customer Charge for qualifying customers. Because EPE is not proposing any change to the provisions of the existing rider, the impact of the higher Customer Charge is to increase the discount provided under the rider.

Q61. WILL THE INCREASE IN THE CUSTOMER CHARGE FOR THE RESIDENTIAL SERVICE RATE AFFECT THE CUSTOMERS' ABILITY TO CONTROL THEIR ENERGY USAGE?

A. No. Even with the proposed monthly Customer Charge, residential customers are still able to maintain control of their electric bill by managing energy consumption and taking advantage of opportunities aimed at reducing their energy usage through energy efficiency programs or conservation. Under EPE's proposed residential rate design, for most customers the predominant charge on the customer's bill will still be the volumetric Energy Charge, which is under the customer's control. The proposed customer charges represent approximately 12% of the base rate charges, which also means that residential customers will keep control over more than 87% of their monthly bill. For low-income residential customers, which qualify for the Low-Income Rider, the customer charge will represent 0% of their monthly bill because the essential benefit provided by this rider is that qualifying customers do not pay the Customer Charge. This relative impact of customer charges on residential customers' bills is lessened further when other rates and riders are considered.

Q62. HAS THE COMPANY COMPARED THE RESIDENTIAL BILLS UNDER CURRENT AND PROPOSED STANDARD SERVICE RATES BY BILL COMPONENT?

A. Yes. Exhibit MC-7 shows a comparison of monthly residential bills, using the average Residential monthly consumption for the Test Year of 658 kWh. As shown in the exhibit's Chart 1, for the proposed non-summer months, the bill under proposed rates is roughly $88 under the proposed rates, compared to $73 under current rates. For proposed summer months, the bills under proposed rates are roughly $181 under the proposed rates, compared to $143 under current rates.

The exhibit's Chart 2 provides the change in average bill for each month. For low average usage months, the increase in electric bills is slightly less than $15. For higher average usage months, the bills are roughly $38 more per month, indicating a pricing signal to encourage power conservation. An interesting observation in the graph is the lower bill impact for May and October, which are months that are now non-summer months in EPE's proposed rate structure.

Q63. WHAT CHANGES ARE PROPOSED FOR THE ALTERNATIVE TOD RATE OPTION?

A. EPE is proposing to set the customer charge equal to the proposed Standard Service Rate customer charge. As explained previously, recovering these customer costs in the most appropriate manner means that the TOD Energy Charges offered under the rate provide accurate price signals.

In addition, the non-summer Energy Charge for the TOD Rate is also set equal to the proposed non-summer Energy Charge for the Standard Service Rate. This is because there is no reason for TOD customers to receive the benefit of a lower Energy Charge as compared to non-TOD customers during non-summer months, when EPE's system has sufficient capacity to serve both types of customers.

Finally, the Company is proposing to modify the On-Peak Period to Off-Peak Period Charge differential to reflect EPE's current generation costs.

Q64. HOW DO EPE'S PROPOSED TOD RATES FOR ITS RESIDENTIAL CUSTOMERS COMPARE TO OTHER SIMILAR TIME-VARIANT RATE OFFERINGS IN THE COUNTRY?

A. A recent survey report published by The Brattle Group on Residential Time-Of-Use (or

TOD) rates offered by electric utilities found that the median On-peak period to off-peak period price ratio for TOU rates is 2.7-to-1, where 71% of the TOU rates have a price ratio of at least 2-to-1; and for TOU rates designed recently (i.e., those developed for pricing pilots in the past decade) typically have a peak period of six hours or less. Furthermore, the Brattle report recommends a 4 to 1 price ratio for the rate pilot of the residential rate class and a peak period of five hours.

EPE's proposed On-peak period to off-peak period ratio is 3.40-to-1 (the current ratio is 3.42-to-1), with a peak period of five hours. Therefore, EPE's proposed Alternative TOD Rate price signal for Residential customers are reasonably in line with many other time-variant rate offerings in the country and provide a reasonable economic incentive for customers to consider participation in the TOD rate offering and to change their usage patterns.

Q65. HOW HAS EPE ENCOURAGED PARTICIPATION IN THE ALTERNATIVE TOD RATE OPTION?

A. Rate Schedule No. 01 offers a bill protection clause that removes the risk of severe bill impact in the initial twelve months after a customer switch to the Alternative TOD Rate option. If, at the conclusion of the initial 12-month period of service under the TOD rate option, the total billings exceed billings for the same period under the Standard Service rate, the customer may opt to revert to the Standard Service rate. In this event, the Company will reset the customer's account to the Standard Service rate and provide a credit to the customer for the difference in billings under the Alternative TOD Rate option and the Standard Service rate for the 12-month review period. This bill protection provision is limited to the first 500 new customers to enroll in the TOD Rate option. As previously discussed, this bill protection provision's limitation is proposed for revision in this rate case.

Q66. WHAT CHANGES ARE PROPOSED FOR THE DEMAND CHARGE TOD RATE?

A. EPE is proposing to set the customer charge equal to the proposed Standard Service Rate Customer Charge. The rate structure will maintain the flat Demand Charge per kW applicable in all months. The Demand Charge will be complemented with Energy Charges that account for the recovery of the distribution-related costs of the Residential Service rate class through the Demand Charge. In addition, the Company is proposing to modify the On-Peak Period to Off-Peak Period Energy Charge differential to reflect EPE's current incremental capacity costs.

Q67. WHY IS THE DEMAND CHARGE TOD RATE OFFERED AS A RATE OPTION?

A. Residential demand charge rates are not very common, although some utilities have had them in place for several years. As an optional offering to EPE residential customers, it was necessary to first gauge how such rates would be received by customers. Although EPE limited participation to only 500 customers, only 32 bills were issued as of the end of the Test Year (most of which went to DG customers), indicating a modest level of interest for this rate option at this time. EPE is proposing to remove the participation limitation and continue to make this option available to additional participants.

In other non-residential rate classes, demand-related costs are generally recovered through a demand charge applied to the billed kW or maximum load drawn by customers in any given month. Because electric systems are built and sized to meet the electric needs of customers at every point in time, including periods when electricity demand reaches its maximum, demand charges allow utilities to recover these fixed costs through a rate element that more accurately reflects the way these costs are incurred to meet the customers' instantaneous demand. In EPE's rate structures, these demand charges are assessed to customers based on their highest level of electric usage at any given moment during each billing period.

Q68. PLEASE DESCRIBE THE MONTHLY MINIMUM CHARGE PROVISION.

A. The monthly minimum charge provision in the currently effective Rate Schedule No. 01 was first implemented because of the settlement stipulation in EPE's 2017 Texas Rate Case, Docket No. 46831. For non-DG customers and grandfathered DG customers, the Monthly Minimum Charge is the Customer Charge. For non-grandfathered DG customers, the Monthly Minimum Charge depends on which rate option they select to take service under. Discussion of the grandfathering provision was included in Attachment 7 of the stipulation and agreement in Docket No. 46831.

Q69. HOW WERE THE TWO MINIMUM BILL AMOUNTS SHOWN AS APPLICABLE TO NON-GRANDFATHERED DG CUSTOMERS IN THE MONTHLY MINIMUM CHARGE PROVISION DETERMINED?

A. Those charges were the result of the settlement stipulation negotiations in EPE's prior rate cases. One component of the minimum bill amounts is the Customer Charge that all Rate Schedule No. 01 customers are subjected to.

Q70. IS EPE PROPOSING TO REVISE THE MINIMUM BILL AMOUNTS APPLICABLE TO NON-GRANDFATHERED DG CUSTOMERS? IF SO, PLEASE EXPLAIN THE RATIONALE FOR THE REVISED MINIMUM BILL AMOUNTS.

A. Yes. EPE is proposing to eliminate the minimum bill amounts and to place the non-grandfathered DG customers under the new proposed Distributed Generation Rate.

Q71. WHAT IS THE BASIS FOR THE PROPOSAL TO REQUIRE DG CUSTOMERS TO TAKE SERVICE UNDER THE DISTRIBUTED GENERATION RATE?

A. The currently effective minimum bill amounts, while likely closer to capturing the costs associated with serving DG customers, are not cost-based since they are the result of compromise and settlement. In contrast, EPE's proposed Distributed Generation Rate is supported by the cost-of-service studies filed in this rate case.

Furthermore, some DG customers have expressed dissatisfaction with the minimum bill amounts through complaints filed with the Commission. Additionally, the advanced meters that are getting deployed provide near real-time information (15-minute interval kW reads), which means customers can much easily determine when their non-coincident peak occurs, allowing them to better manage their loads.

Q72. WHY DOES EPE BELIEVE IT IS APPROPRIATE TO REQUIRE DG CUSTOMERS TO TAKE SERVICE UNDER THE PROPOSED DISTRIBUTED GENERATION RATE?

A. EPE is proposing that DG customers take service under a rate structure that includes a demand charge because EPE believes that this is the best rate design for recovering the demand-related costs that these customers impose on EPE's system and for preventing intra-rate class subsidization of DG customers.

As explained by EPE witness Soto, EPE's load studies show that DG customers have a significantly different usage profile than EPE's typical non-DG customers. This is particularly true with net-metering which reduces the customer's billed monthly consumption when they are a net-producer during certain hours of the day. DG customers tend to be customers with relatively high demand, but low-load factor, meaning that they are billed less total energy relative to their peak demand in comparison to EPE's residential non-DG customers. EPE's load studies, also show that DG customers on average have a 24% higher monthly peak demand while having a 79% lower load factor.

Furthermore, net metering can result in a DG customer having a bill with no net charge for energy used during the month, despite having put demand on EPE's generation, transmission, and distribution system during the early evening hours, when native system peak demand is still high. For example, approximately 1 in 6 of the bills that EPE issued to residential DG customers in September 2024 under the current residential rate design consist exclusively of the minimum bill amount because the meter has rolled-back all of the electricity delivered to that customer during the month.[8] Consequently, the standard residential rate, which relies on volumetric energy charges that reflect average monthly consumption relative to peak-demand for recovery of demand costs, is not well designed to capture the demand costs that DG customers put on EPE's system. The result is that other residential customers subsidize the DG customers creating intra-class inequities. A demand charge would remedy this situation by providing a means, more cost-based than just a minimum bill amount, for the DG customers to pay for the demand-related costs that they are imposing on EPE's system.

Q73. WHAT CHANGES DOES THE COMPANY PROPOSE TO THE OFF-PEAK WATER HEATING SERVICE RIDER?

A. EPE is proposing to increase the monthly Customer Charge from $3.56 to the full cost of $2.67 per month. In addition, as discussed previously, EPE is also proposing an increase

[8] EPE's records, for September 2024, show 24,432 net metered accounts (or 1 in 13 residential accounts). Of those, 3,736 accounts were assessed the minimum bill amount.

in the Energy Charge for this service to recover the cost of serving Off-Peak Water Heating Service Rider customers more adequately.

B. Schedule No. 02 – Small General Service Rate

Q74. PLEASE DESCRIBE THE EXISTING RATE SCHEDULE NO. 02 – SMALL GENERAL SERVICE RATE SCHEDULE.

A. This rate schedule is applicable to customers with peak demand not exceeding 15 kW monthly. The rate schedule includes three monthly rate options: a Standard Service Rate, an Alternative TOD Rate, and a Demand Charge Rate. A clause is included that offers bill protection to the first 150 customers that elect to take service under the Alternative TOD Rate for an initial twelve-month period under that rate option.

The rate schedule also includes provisions for determination of billing demand and for a monthly minimum charge, including special applicable charges to DG customers. It also includes a reference to other applicable riders, as well as terms and conditions that apply to service under this schedule. Other rate provision currently offered under the rate schedule include an Off-Peak Water Heating Rider, which is closed to new service applications, and a provision for non-metered service.

Q75. PLEASE DESCRIBE THE EXISTING STRUCTURE OF THE RATES OFFERED UNDER RATE SCHEDULE NO. 02.

A. The Standard Service Rate structure consists of a monthly Customer Charge and seasonal Energy Charges in which the summer Energy Charge includes slightly more than one cent per kWh price differential over the non-summer Energy Charge. The summer Energy Charge applies in the four months of June through September.

The Alternative TOD Rate consists of a monthly Customer Charge and Energy Charges that apply based on the month, day, and hour that usage occurs. The On-Peak Period Energy Charge applies from noon to 6:00 P.M., weekdays during the summer period, and the Off-Peak Period Energy Charge applies during all other hours.

The Demand Charge Rate consists of a monthly Customer Charge, a flat Demand Charge, and Energy Charges that apply based on the month, day, and hour that usage occurs. The On-Peak Period Energy Charge applies from noon to 6:00 P.M., weekdays during the summer period, the Off-Peak Period Energy Charge applies during all other hours.

Q76. OTHER THAN THE BROADLY APPLICABLE LANGUAGE CHANGES, WHAT OTHER SIGNIFICANT LANGUAGE CHANGES ARE PROPOSED FOR RATE SCHEDULE NO. 02?

A. Like the proposal in Schedule No. 01, the two minimum bill amounts applicable to DG customers are deleted because EPE is proposing for all DG customers that do not meet the grandfathering clause to take service under the new proposed Distributed Generation Rate described below. No other significant language changes are proposed for this rate schedule.

Q77. WHAT CHANGES DOES EPE PROPOSE FOR THE RATE SCHEDULE NO. 02 RATES AND RATE STRUCTURES?

A. For the Standard Service Rate, EPE is proposing to:

(1) set the monthly Customer Charge to collect all the customer-related costs; and
(2) increase the price differential between summer and non-summer Energy Charges.

For the Alternative TOD Rate, EPE is proposing to:

(1) set the monthly Customer Charge equal to the Standard Service Rate Monthly Customer Charge;
(2) set the non-summer Off-Peak Period Energy Charge equal to the Standard Service Rate non-summer Energy Charge; and
(3) to the extent possible, increase the price differential between On-Peak Period and Off-Peak Period summer Energy Charges.

For the Demand Charge Rate, EPE is proposing to:

(1) set the monthly Customer Charge equal to the Standard Service Rate Monthly Customer Charge;
(2) set the Demand Charge to fully reflect distribution-related costs;
(3) set the non-summer Off-Peak Period Energy Charge equal to the Standard Service Rate non-summer Energy Charge, less an amount commensurate to the distribution-related costs recovered through the Demand Charge; and
(4) to the extent possible, increase the price differential between On-Peak Period and

Off-Peak Period summer Energy Charges.

For the new Distributed Generation Rate, EPE is proposing to:

(1) set the monthly Customer Charge equal to the Standard Service Rate Monthly Customer Charge;

(2) set the Demand Charge to reflect the distribution demand-related cost, at full-cost, plus a ten percent (10 percent) adder for the demand-related components of transmission and production demand-related cost; and

(3) set the Energy Charge equal to the Standard Service Rate Energy Charge, less an amount commensurate to the demand-related costs recovered through the Demand Charge.

Exhibit MC-3 provides a comparison of current and proposed rate component for each of the rate options of all the proposed rate schedules.

Q78. WHY IS EPE PROPOSING TO INCREASE THE CUSTOMER CHARGE FOR THE SMALL GENERAL SERVICE RATE?

A. EPE is proposing to increase the monthly Customer Charge for Small General Service from $12.23 to $15.77. As noted previously, EPE is proposing to increase the Customer Charge to recover its customer-related costs more adequately and to reduce the amount of fixed customer-related costs recovered through the volumetric Energy Charge. This improves the accuracy of the price signal the Small General Service energy rate provides to customers.

Q79. HAS THE COMPANY ANALYZED THE IMPACT OF THE PROPOSED STANDARD SERVICE RATES ON SMALL GENERAL SERVICE CUSTOMERS WITH VARIOUS USAGE CHARACTERISTICS?

A. Yes. RFP Schedule Q-8.9 provides bill impacts based on various levels of electric usage.

Q80. WHY IS EPE PROPOSING TO INCREASE THE PRICE DIFFERENTIAL BETWEEN SUMMER AND NON-SUMMER ENERGY CHARGES?

A. As noted previously, EPE is proposing rate structures that encourage energy conservation and potentially reduce customers' contribution to EPE's system peak. The price differential between the Standard Service Rate summer and non-summer Energy Charge is proposed to increase to two cents from the current one cent differential.

Q81. WHY IS THE DEMAND CHARGE RATE OFFERED AS A RATE OPTION?

A. Demand charge rates are not very common for small commercial customers, although some utilities have had them in place for several years. As an optional offering to EPE small commercial customers, it was necessary to first gauge how such rates will be received by customers. As of the end of the Test Year, EPE issued 701 bills under this Rate Schedule No. 02 Demand Charge Rate option, indicating a strong interest by customers for this rate option.

Q82. HAS EPE PROPOSED THE SAME CHANGES TO THE MONTHLY MINIMUM CHARGE PROVISION OF RATE SCHEDULE NO. 02 AS THOSE DESCRIBED FOR THE MONTHLY MINIMUM CHARGE PROVISION OF RATE SCHEDULE NO. 01?

A. Yes. A new Distributed Generation Rate is also proposed under Rate Schedule No. 02.

Q83. ARE THE CHANGES THE COMPANY PROPOSED TO THE OFF-PEAK WATER HEATING SERVICE RIDER IN RATE SCHEDULE NO. 01 THE SAME FOR RATE SCHEDULE NO. 02 OFF-PEAK WATER HEATING SERVICE RIDER?

A. Yes.

C. Schedule No. 07 – Outdoor Recreational Lighting Service Rate

Q84. PLEASE DESCRIBE THE EXISTING RATE SCHEDULE NO. 07 – OUTDOOR RECREATIONAL LIGHTING SERVICE RATE.

A. This rate schedule is applicable solely for outdoor recreational lighting installations, such as athletic fields, racetracks, and other sport or recreational facilities. The rate schedule consists of a single rate option and includes provisions that refer to other applicable riders as well as terms and conditions that apply to service under this schedule.

Q85. PLEASE DESCRIBE THE EXISTING STRUCTURE OF RATES OFFERED UNDER RATE SCHEDULE NO. 07.

A. The rate structure consists of a monthly Customer Charge and a flat Energy Charge (differentiated by primary and secondary service voltage).

Q86. OTHER THAN THE BROADLY APPLICABLE LANGUAGE CHANGES, WHAT SIGNIFICANT LANGUAGE CHANGES ARE PROPOSED FOR RATE SCHEDULE NO. 07?

A. No other significant language changes are proposed for this rate schedule.

Q87. WHAT CHANGES DOES EPE PROPOSE FOR THE RATE SCHEDULE NO. 07 RATES AND RATE STRUCTURES?

A. EPE is proposing to retain the two-part rate structure and set the monthly Customer Charge to fully collect all the customer-related costs through that charge.

D. Schedule No. 08 – Governmental Street Lighting Service

Q88. PLEASE DESCRIBE THE EXISTING RATE SCHEDULE NO. 08 – GOVERNMENTAL STREET LIGHTING SERVICE RATE ("STREET LIGHTING") AND THE STRUCTURE OF RATES OFFERED UNDER IT.

A. Street Lighting Service is applicable to any municipality, county, the State of Texas, and federal facilities for street and freeway lighting. Rates, in the form of monthly per-lamp charges, are provided for Company-owned and customer-owned systems. This schedule also offers a metered option, with a few customers taking service under this option at Test Year-end. Service to some LED streetlights is based on the energy consumed. The charge for energy consumed is determined within EPE's billing system based on the wattage of the lamp and set burning hours.

Q89. IS EPE SEEKING A CHANGE TO ITS RATE SCHEDULE NO. 08?

A. Yes. Please refer to the direct testimony of EPE witness Rene Gonzalez for discussion of the changes to this schedule.

E. Schedule No. 09 – Traffic Signal Service

Q90. PLEASE DESCRIBE THE EXISTING RATE SCHEDULE NO. 09 – TRAFFIC SIGNAL

SERVICE RATE STRUCTURE OF RATES OFFERED UNDER IT.

A. Traffic Signal Service is applicable to any municipality, county, the State of Texas, and federal facilities for traffic signal lighting. Rates, in the form of monthly per-lamp charges, are provided for customer-owned systems. This schedule offers a metered option with several customers taking service under this option at Test Year-end.

Q91. IS EPE SEEKING A CHANGE TO ITS RATE SCHEDULE NO. 09?

A. Yes. Please refer to the direct testimony of EPE witness Rene Gonzalez for discussion of the changes to this schedule.

F. Schedule No. 11 – Municipal Pumping Service

Q92. PLEASE DESCRIBE THE EXISTING RATE SCHEDULE NO. 11 – MUNICIPAL PUMPING SERVICE RATE.

A. This rate schedule is solely applicable to counties, municipalities, and other legal property taxing authorities who receive service for pumping of water, sewage, storm water, and sewage disposal. The rate schedule consists of a TOD rate and includes provisions for meter voltage adjustments and refer to other applicable riders as well as terms and conditions that apply to service under this schedule.

Q93. PLEASE DESCRIBE THE EXISTING RATE STRUCTURE OF RATE SCHEDULE NO. 11.

A. The rate structure consists of a monthly Customer Charge and Energy Charges (differentiated by primary and secondary service voltage) for three rating periods applicable in the weekdays during the summer period: On-peak, shoulder-peak, and off-peak. The On-peak period is defined as 1:00 P.M. through 5:00 P.M., Monday through Friday. The shoulder-peak period is defined as 10:00 A.M. through 12:59 P.M. and 5:01 P.M. through 8:00 P.M., Monday through Friday. The off-peak period is comprised of all other hours in the summer period. The non-summer Energy Charge is applied to all usage in the months of October through May.

Q94. OTHER THAN THE BROADLY APPLICABLE LANGUAGE CHANGES, WHAT

SIGNIFICANT LANGUAGE CHANGES ARE PROPOSED FOR RATE SCHEDULE NO. 11?

A. The hours of the On-peak period are redefined as 2:00 P.M. through 6:00 P.M. and the hours of the shoulder-peak period are redefined as 12:00 P.M through 1:59 P.M. and 6:01 P.M. through 8:00 P.M. No other significant language changes are proposed for this rate schedule.

Q95. WHAT CHANGES DOES EPE PROPOSE FOR RATE SCHEDULE NO. 11 RATES AND RATE STRUCTURES?

A. EPE is proposing to retain the two-part (Customer and Energy Charge) rate structure, including the three rating periods and set the monthly Customer Charge to fully collect all the customer-related costs through that charge.

Q96. WHY ARE THE PRICING PERIODS FOR THE MUNICIPAL PUMPING SERVICE RATE DIFFERENT FROM THE ON-PEAK PERIOD FOR OTHER TOD RATES?

A. The pricing periods were developed in cooperation with El Paso Water Utilities several years ago and are designed to provide a strong economic incentive to encourage municipal water pumping loads to reduce consumption during the most critical On-peak hours and to provide a smaller, but still significant, economic incentive to reduce consumption during the shoulder-peak hours.

G. Schedule No. 15 – Electrolytic Refining Service Rate

Q97. PLEASE DESCRIBE THE EXISTING RATE SCHEDULE NO. 15 – ELECTROLYTIC REFINING SERVICE RATE.

A. Rate Schedule No. 15 is closed to new service applications and is applicable to existing customers that receive service for electrolytic refining facilities with minimum contracted capacity of 7,500 kW. The rate schedule consists of a single rate option and includes provisions for determination of billing demand, a power factor adjustment, and an interconnection charge. The determination of billing demand includes a 65% demand ratchet. The rate schedule also includes provisions that refer to other applicable riders as well as terms and conditions that apply to service under this schedule.

Q98. PLEASE DESCRIBE THE EXISTING RATE STRUCTURE OF RATE SCHEDULE NO. 15.

A. The rate structure consists of a monthly Customer Charge, a seasonal Demand Charge, and a TOD Energy Charge. The summer Demand and summer Energy Charges apply in the months of June through September. The On-Peak Period Energy Charge applies from noon to 6:00 P.M., weekdays during the summer period, and the Off-Peak Period Energy Charge applies during all other hours.

Q99. OTHER THAN THE BROADLY APPLICABLE LANGUAGE CHANGES, WHAT OTHER SIGNIFICANT LANGUAGE CHANGES ARE PROPOSED FOR RATE SCHEDULE NO. 15?

A. The language regarding reduction of contract capacity by June 1, 2023, is removed. No other significant language changes are proposed for this rate schedule.

Q100. WHAT CHANGES DOES EPE PROPOSE FOR THE RATE SCHEDULE NO. 15 RATES AND RATE STRUCTURES?

A. EPE is proposing to set the monthly Customer Charge to fully collect all the customer-related costs through that charge. The Demand Charge is set to reflect the underlying demand-related costs of this rate class.

Q101. HOW ARE THE RATE SCHEDULE NO. 15 DEMAND AND ENERGY CHARGES CALCULATED?

A. The proposed Demand Charge reflects a seasonal price differential to recognize the higher loads experienced on EPE's system in the summer months. The summer Demand Charge includes 25% of EPE's incremental capacity cost to be recovered in the On-Peak Period and the On-Peak Period Energy Charge includes the remaining amount. The Off-Peak Period Energy Charge is set to recover all costs not recovered through the other rate components.

H. Schedule No. 22 – Irrigation Service Rate

Q102. PLEASE DESCRIBE THE EXISTING RATE SCHEDULE NO. 22 – IRRIGATION SERVICE RATE.

A. This rate schedule is applicable solely for irrigation water pumping with loads of 15 kW or larger. The rate schedule includes two monthly rate options: a Standard Service Rate and an Alternative TOD Rate. The Standard Service is closed to new service applications. A clause is included that offers bill protection to customers that elect to take service under the Alternative TOD Rate for an initial twelve-month period under that rate option. It also includes a provision for a monthly minimum charge, a reference to other applicable riders, as well as terms and conditions that apply to service under this schedule.

Q103. PLEASE DESCRIBE THE EXISTING STRUCTURE OF RATES OFFERED UNDER RATE SCHEDULE NO. 22.

A. The Standard Service Rate structure consists of a monthly Customer Charge and seasonal Energy Charges in which the summer Energy Charge includes a nearly $0.03 per kWh price differential over the non-summer Energy Charge. The summer Energy Charge applies in the months of June through September.

The Alternative TOD Rate consists of a monthly Customer Charge and Energy Charges that apply based on the month, day, and hour that usage occurs. The On-Peak Period Energy Charge applies from 1:00 P.M. through 5:00 P.M., weekdays during the summer period, June through September, and the Off-Peak Period Energy Charge applies during all other hours.

Q104. OTHER THAN THE BROADLY APPLICABLE LANGUAGE CHANGES, WHAT OTHER SIGNIFICANT LANGUAGE CHANGES ARE PROPOSED FOR RATE SCHEDULE NO. 22?

A. The hours of the On-peak period are redefined as 2:00 P.M. through 6:00 P.M. No other significant language changes are proposed for this rate schedule.

Q105. WHAT CHANGES DOES EPE PROPOSE FOR THE RATE SCHEDULE NO. 22 RATES AND RATE STRUCTURES?

A. For the Standard Service Rate, EPE is proposing to

(1) set the monthly Customer Charge to collect all the customer-related costs; and

(2) increase the price differential between summer and non-summer Energy Charges to $0.04 from the current near $0.03 differential.

For the Alternative TOD Rate, EPE is proposing to:

(1) set the monthly Customer Charge equal to the Standard Service Rate Monthly Customer Charge; and

(2) set the non-summer Off-Peak Period Energy Charge equal to the Standard Service Rate non-summer Energy Charge; and

(3) to the extent possible, increase the price differential between the On-Peak Period and summer Off-Peak Period Energy Charges.

I. Schedule No. 24 – General Service

Q106. PLEASE DESCRIBE THE EXISTING RATE SCHEDULE NO. 24 – GENERAL SERVICE RATE.

A. This rate schedule is applicable to customers with peak metered demand exceeding 15 kW and up to 600 kW. The rate schedule includes two monthly rate options: a Standard Service Rate and an Alternative TOD Rate. The Standard Service Rate is closed to new service applications with projected demand equal to or greater than 300 kW. A clause is included that offers bill protection to customers that elect to take service under the Alternative TOD Rate for an initial twelve-month period under that rate option. An additional clause offers new customers that are required to take service under the Alternative TOD Rate the ability to take service under the Standard Service Rate after an initial twelve-month period under the Alternative TOD Rate. Rate Schedule No. 24 also includes an Experimental Off-Peak Rate Rider, which is applicable to certain qualifying customers whose average load factor does not exceed 30%.

Other provisions currently included under Rate Schedule No. 24 is a Thermal Energy Storage (TES) Rider and an Off-Peak Water Heating Rider, which is closed to new service applications; a meter voltage adjustment applicable for certain customers; a power factor adjustment, which is applicable to customers with historical maximum demands of 250 kW and above; and a determination of billing demand with a 60% demand ratchet. It also includes reference to other applicable riders as well as terms and conditions that apply to service under this schedule.

Q107. PLEASE DESCRIBE THE EXISTING STRUCTURE OF THE RATES OFFERED UNDER RATE SCHEDULE NO. 24.

A. The Standard Service Rate structure consists of a monthly Customer Charge, seasonal Demand Charges, and a load factor-blocked Energy Charge (differentiated by service voltages). The three-step energy blocks are a function of the customer's energy use per kW of demand, with declining Energy Charges applying with progressively higher load factors (otherwise known as an "hours use of demand" rate structure). The summer Demand and summer Energy Charges apply in the months of June through September.

The Alternative TOD Rate consists of a monthly Customer Charge, seasonal Demand Charges, and Energy Charges that apply based on the month, day, and hour that usage occurs. The summer Demand and summer Energy Charges apply in the months of June through September. The On-Peak Period Energy Charge applies from noon to 6:00 P.M., weekdays during the summer period, and the Off-Peak Period Energy Charge applies during all other hours.

Q108. OTHER THAN THE BROADLY APPLICABLE LANGUAGE CHANGES, WHAT OTHER SIGNIFICANT LANGUAGE CHANGES ARE PROPOSED FOR RATE SCHEDULE NO. 24?

A. The Experimental Off-Peak Rate Rider is eliminated due to lack of interest from customers. No other significant language changes are proposed for this rate schedule. This is another class for which EPE is proposing to implement a Reserved Distribution Capacity Service Charge, as described earlier in this section of the testimony, which will be billed to customers that request back-up for their primary voltage loads.

Q109. WHAT CHANGES DOES EPE PROPOSE FOR RATE SCHEDULE NO. 24 RATES AND RATE STRUCTURES?

A. For the Standard Service Rate, EPE is proposing to:

(1) set the monthly Customer Charge to collect all the customer-related costs; and

(2) increase the price differential between summer and non-summer Demand and reduce the price differential between summer and non-summer Energy Charges.

For the Alternative TOD Rate, EPE is proposing to:

(1) set the monthly Customer Charge equal to the Standard Service Rate Monthly Customer Charge;

(2) set the Demand Charges equal to the Standard Service Rate Demand Charges; and

(3) to the extent possible, increase the price differential between On-Peak Period and Off-Peak Period summer Energy Charges.

J. Schedule No. 25 – Large Power Service

Q110. PLEASE DESCRIBE THE EXISTING RATE SCHEDULE NO. 25 – LARGE POWER SERVICE RATE.

A. This rate schedule is applicable to most of EPE's largest commercial and industrial customers with peak demand exceeding 600 kW and for whom no other rate schedule applies. The rate schedule contains a single monthly time varying rate option that is differentiated by transmission, primary, and secondary voltage service. Rate Schedule No. 25 also includes an Experimental Off-Peak Rate Rider, which is applicable to certain qualifying customers whose average load factor does not exceed 30%.

Provisions currently included under Rate Schedule No. 25 are a TES Rider; a meter voltage adjustment applicable for certain customers; a power factor adjustment, which is applicable under certain circumstances; and a determination of billing demand with a 75% demand ratchet. It also includes reference to other applicable riders as well as terms and conditions that apply to service under this schedule.

Q111. PLEASE DESCRIBE THE EXISTING RATE STRUCTURE OF RATE SCHEDULE NO. 25.

A. The rate structure consists of a monthly Customer Charge, a seasonal Demand Charge, and a TOD Energy Charge. The summer Demand and summer Energy Charges apply in the months of June through September. The On-Peak Period Energy Charge applies from noon to 6:00 P.M., weekdays during the summer period, and the Off-Peak Period Energy Charge applies during all other hours.

Q112. OTHER THAN THE BROADLY APPLICABLE LANGUAGE CHANGES, WHAT OTHER SIGNIFICANT LANGUAGE CHANGES ARE PROPOSED FOR RATE SCHEDULE NO. 25?

A. The Experimental Off-Peak Rate Rider is proposed as a permanent option and no longer considered "experimental" as it has proven to be a beneficial rate structure. Also, an Interconnection Charge provision was added to ensure that customers that are served under this rate schedule are properly responsible for costs that the Company has incurred or will incur to interconnect with the customer's qualifying facility. No other significant language changes are proposed for this rate schedule. However, this is a class for which EPE is proposing to implement a Reserved Distribution Capacity Service Charge, as described earlier in this section of the testimony, which will be billed to customers that request back-up for their primary voltage loads.

Q113. WHAT RATE CHANGES DOES EPE PROPOSE FOR RATE SCHEDULE NO. 25?

A. EPE is proposing to:

(1) set the monthly Customer Charge to collect all the customer-related costs;

(2) increase the price differential between summer and non-summer Demand Charges; and

(3) to the extent possible, increase the price differential between On-Peak Period and Off-Peak Period summer Energy Charges.

Q114. PLEASE DESCRIBE THE OFF-PEAK RATE RIDER.

A. The Off-Peak Rate Rider was originally proposed in Docket No. 40641[9] as an experimental tariff available to customers who qualify under Rate Schedule No. 25 and who have a low load factor—defined as a twelve-month average load factor of less than 30%. The rate structure has the same on-peak period and off-peak period energy charges as those offered under the standard Rate Schedule No. 25 rates. However, rather than a single Demand Charge that applies to maximum metered demand, the Off-Peak Rate Rider has both a

[9] *Petition of El Paso Electric Company for Approval of Rate Schedule No. 25a – Large Power Service, Experimental Off-Peak Rate*, Docket No. 40641, Notice of Approval (Sept. 28, 2012).

maximum Demand Charge and an On-Peak Period Demand Charge. The On-Peak Period Demand Charge is applied to 100% of the peak metered demand during the on-peak period for the billing cycle or during the last 11 months, while the maximum Demand Charge is set at a lower rate per kW than the standard Schedule No. 25 Demand Charge. The rate is designed to provide a financial incentive to encourage maximum demand use during the off-peak period rather than the on-peak period. Customers that can do this will both lower their own electric bills and assist in lowering EPE's summer peak demand, which benefits all customers by reducing the demand that EPE must meet through generation.

When the Off-Peak Rate Rider was originally proposed in 2012, three qualifying customers signed up for service. Since then, two of the qualifying customers have shut down operations. The remaining customer has continued to take service under this rider, benefiting from the financial incentive that it provides. EPE believes that the rate structure may offer an opportunity in the future for similarly situated customers.

Q115. WHAT CHANGES ARE PROPOSED FOR THE OFF-PEAK RATE?

A. No structural changes to the Off-Peak Rate Rider are proposed, other than making it a permanent rate structure.

K. Schedule No. 26 – Petroleum Refinery Service

Q116. PLEASE DESCRIBE THE EXISTING RATE SCHEDULE NO. 26 – PETROLEUM REFINERY SERVICE RATE.

A. Rate Schedule No. 26 is applicable to customers operating petroleum refining facilities with peak demand exceeding 3,000 kW. The rate schedule consists of a single rate option and includes provisions for determination of billing demand, a power factor adjustment, and a charge for facilities constructed by the Company that are not reflected in the rates of the schedule. The determination of billing demand includes a 65% demand ratchet. The rate schedule also includes provisions that refer to other applicable riders as well as terms and conditions that apply to service under this schedule.

Q117. PLEASE DESCRIBE THE EXISTING RATE STRUCTURE OF RATE SCHEDULE NO. 26.

A. The rate structure consists of a monthly Customer Charge, a seasonal Demand Charge, and a uniform Energy Charge. The summer Demand Charge applies in the months of June through September.

Q118. OTHER THAN THE BROADLY APPLICABLE LANGUAGE CHANGES, WHAT SIGNIFICANT LANGUAGE CHANGES ARE PROPOSED FOR SCHEDULE NO. 26?

A. No significant language changes are proposed for this rate schedule.

Q119. WHAT CHANGES DOES EPE PROPOSE FOR THE RATE SCHEDULE NO. 26 RATES AND RATE STRUCTURES

A. EPE is proposing to set the monthly Customer Charge to fully collect all the customer-related costs through that charge. The Demand Charge is set to reflect the underlying demand-related costs of this rate class.

Q120. HOW ARE THE RATE SCHEDULE NO. 26 DEMAND AND ENERGY CHARGES CALCULATED?

A. The proposed Demand Charge reflects a seasonal price differential to recognize the higher loads experienced on EPE's system in the summer months. The summer Demand Charge includes 25% of EPE's incremental capacity cost to be recovered in the On-Peak Period. The Energy Charge is set to recover all costs not recovered through the other rate components.

L. Schedule No. 28 – Area Lighting

Q121. PLEASE DESCRIBE THE EXISTING STRUCTURE OF RATES OFFERED UNDER RATE SCHEDULE NO. 28 – AREA LIGHTING SERVICE RATE.

A. Area Lighting Service is available to any customer who desires overhead outdoor lighting. Rates, in the form of monthly per lamp charges, are provided for Company-owned systems. The service is unmetered and consists of monthly charges differentiated by lighting technology and wattage.

Q122. IS EPE SEEKING A CHANGE TO ITS RATE SCHEDULE NO. 28?

A. Yes. Please refer to the direct testimony of EPE witness Rene Gonzalez for discussion of the changes to this schedule.

M. Schedule No. 30 – Electric Furnace Rate

Q123. PLEASE DESCRIBE THE EXISTING RATE SCHEDULE NO. 30 – ELECTRIC FURNACE SERVICE RATE.

A. Rate Schedule No. 30 is closed to new service applications from new and existing customers and is applicable to existing customers that receive service for electric furnaces for metal melting, with individual furnace or furnaces having nameplate ratings of at least 5,000 kW. The rate schedule consists of a single rate option and includes provisions for determination of billing demand, a power factor adjustment, and an interconnection charge. The determination of billing demand includes a 65% demand ratchet. The rate schedule also includes provisions that refer to other applicable riders as well as terms and conditions that apply to service under this schedule.

Q124. PLEASE DESCRIBE THE EXISTING RATE STRUCTURE OF RATE SCHEDULE NO. 30.

A. The rate structure consists of a monthly Customer Charge, a seasonal Demand Charge, and a TOD Energy Charge. The summer Demand and summer Energy Charges apply in the months of June through September. The On-Peak Period Energy Charge applies from noon to 6:00 P.M., weekdays during the summer period, and the Off-Peak Period Energy Charge applies during all other hours.

Q125. OTHER THAN THE BROADLY APPLICABLE LANGUAGE CHANGES, WHAT OTHER SIGNIFICANT LANGUAGE CHANGES ARE PROPOSED FOR RATE SCHEDULE NO. 30?

A. To allow for the possibility that the existing customer may desire to expand its operations and continue to be served under Rate Schedule No. 30, the Applicability provision is revised to indicate the rate schedule is closed to new service applications from new customers only. No other significant language changes are proposed for this rate schedule.

Q126. WHAT CHANGES DOES EPE PROPOSE FOR THE RATE SCHEDULE NO. 30 RATES AND RATE STRUCTURES?

A. EPE is proposing to set the monthly Customer Charge to fully collect all the customer-related costs through that charge. The Demand Charge is set to reflect the underlying demand-related costs of this rate class.

Q127. HOW ARE THE RATE SCHEDULE NO. 30 DEMAND AND ENERGY CHARGES CALCULATED?

A. The proposed Demand Charge reflects a seasonal price differential to recognize the higher loads experienced on EPE's system in the summer months. The summer Demand Charge includes 25% of EPE's incremental capacity cost to be recovered in the On-Peak Period and the On-Peak Period Energy Charge includes the remaining amount. The Off-Peak Period Energy Charge is set to recover all costs not recovered through the other rate components.

N. Schedule No. 31 – Military Reservation Service

Q128. PLEASE DESCRIBE THE EXISTING RATE SCHEDULE NO. 31 – MILITARY RESERVATION SERVICE RATE.

A. Rate Schedule No. 31 is applicable exclusively to the United States Department of Defense for electric service to the Fort Bliss Military Reservation ("Fort Bliss") with minimum contracted capacity of 15,000 kW. The most recent amendment to the agreement to the contract for power service between EPE and Fort Bliss lists 14 service points of delivery, with voltages of 115 kilovolts (kV) or 13.8 kV.

The rate schedule consists of a single rate option and includes provisions for determination of billing demand, a power factor adjustment, and a metering adjustment. The determination of billing demand includes a 65% demand ratchet. The rate schedule also includes provisions that refer to other applicable riders as well as terms and conditions that apply to service under this schedule.

Q129. PLEASE DESCRIBE THE EXISTING RATE STRUCTURE OF RATE SCHEDULE NO. 31.

A. The rate structure consists of a monthly Customer Charge, a seasonal Demand Charge, and a TOD Energy Charge. The summer Demand and summer Energy Charges apply in the months of June through September. The On-Peak Period Energy Charge applies from noon to 6:00 P.M., weekdays during the summer period, and the Off-Peak Period Energy Charge applies during all other hours.

Q130. OTHER THAN THE BROADLY APPLICABLE LANGUAGE CHANGES, WHAT OTHER SIGNIFICANT LANGUAGE CHANGES ARE PROPOSED FOR RATE SCHEDULE NO. 31?

A. No other significant language changes are proposed for this rate schedule.

Q131. WHAT CHANGES DOES EPE PROPOSE FOR THE RATE SCHEDULE NO. 31 RATES AND RATE STRUCTURES?

A. EPE is proposing to set the monthly Customer Charge to fully collect all the customer-related costs through that charge. The Demand Charge is set to reflect the underlying demand-related costs of this rate class.

Q132. HOW ARE THE RATE SCHEDULE NO. 31 DEMAND AND ENERGY CHARGES CALCULATED?

A. The proposed Demand Charge reflects a seasonal price differential to recognize the higher loads experienced on EPE's system in the summer months. The summer Demand Charge includes 25% of EPE's incremental capacity cost to be recovered in the On-Peak Period and the On-Peak Period Energy Charge includes the remaining amount. The Off-Peak Period Energy Charge is set to recover all costs not recovered through the other rate components.

O. Schedule No. 34 – Cotton Gin Service

Q133. PLEASE DESCRIBE THE EXISTING RATE SCHEDULE NO. 34 – COTTON GIN SERVICE RATE.

A. This rate schedule is available to cotton gins for power requirements solely related to the processing of cotton during the defined operating season. All other power requirements (i.e., lighting, office electric load, etc.) are served under the otherwise applicable tariffs. The "operating season" is defined as beginning September 1st of each year (or such date later that a new customer begins service) and extending for at least three months and until April 30 of the following year (eight months maximum). Service taken during any time other than the operating season is billed at the rates of the otherwise applicable rate schedule.

The rate structure consists of a single rate option and includes provisions for determination of billing demand and refer to other applicable riders as well as describing terms and conditions that apply to service under this schedule.

Q134. PLEASE DESCRIBE THE EXISTING RATE STRUCTURE OF RATE SCHEDULE NO. 34.

A. The rate structure consists of an annual Customer Charge, payable in three installments over the operating season, a flat Demand Charge, and a seasonal Energy Charge. These rate components are applicable during the operating season. During the non-operating season, cotton gin customers are billed under the rates and provisions of Rate Schedule No. 02 or Rate Schedule No. 24, depending on which rate schedule the customer otherwise qualifies for.

Q135. OTHER THAN THE BROADLY APPLICABLE LANGUAGE CHANGES, WHAT OTHER SIGNIFICANT LANGUAGE CHANGES ARE PROPOSED FOR RATE SCHEDULE NO. 34?

A. Language was added to the Applicability provision to clarify that service taken during any time other than the regular operating season will be billed the rates and provisions of the otherwise applicable rate schedule. A Monthly Minimum Charge provision, consistent with language in EPE's other rate schedules, was added to the schedule. No other significant language changes are proposed for this rate schedule.

Q136. WHAT CHANGES DOES EPE PROPOSE FOR THE RATE SCHEDULE NO. 34 RATES AND RATE STRUCTURES

A. EPE is proposing to:

(1) set the monthly Customer Charge to fully collect all the customer-related costs;

(2) set the Demand Charge to reflect only the distribution-related cost, at full cost; and

(3) increase the price differential between summer and non-summer Energy Charges to $0.04 from the current $0.03 differential.

P. Schedule No. 38 – Interruptible Power Service

Q137. PLEASE DESCRIBE THE EXISTING RATE SCHEDULE NO. 38 – NOTICED INTERRUPTIBLE POWER SERVICE.

A. Rate Schedule No. 38 is available to customers with total connected capacity requirements of at least 1,000 kW and limited to a maximum of 75 MW for all participating customers. The minimum level of firm demand required from qualifying customers is 600 kW. This schedule is available only in conjunction with firm service under other applicable rate schedules. Interruptible customers effectively provide a capacity resource equal to the difference between their contracted firm service level and their full load requirement. Within 30 minutes of a notice by EPE to interrupt, the customer is required to reduce their demand to their firm service level, subject to penalties provided in the rate schedule.

The rate schedule contains a single rate option (differentiated by transmission, primary, and secondary service voltage) applicable to the interruptible portion of the customer's load. The remaining portion, the "firm service" load, is billed under the otherwise applicable retail rate determined based on the customers total load requirements.

Other provisions currently included under Rate Schedule No. 38 are a power factor adjustment, which is applicable under certain circumstances; reference to other applicable riders; as well as terms and conditions that apply to service under this schedule.

Special provisions in the rate schedule discuss determination of billing demand and energy, contracting for service, scheduling procedures, general conditions, and non-compliance.

Q138. HOW MANY CUSTOMERS DOES EPE SERVE UNDER RATE SCHEDULE NO. 38 AND HOW MUCH CAPACITY DO THEY PROVIDE TO EPE?

A. EPE has eight customers served under Rate Schedule No. 38. Four of those customers take service at transmission voltage and the remaining four customers take service at primary voltage. These customers provide approximately 40 MW of interruptible capacity.

Q139. PLEASE DESCRIBE THE EXISTING RATE STRUCTURE OF RATE SCHEDULE NO. 38.

A. The rate structure consists of a Demand Charge and an Energy Charge, both differentiated by transmission, primary, and secondary voltage service.

Q140. OTHER THAN THE BROADLY APPLICABLE LANGUAGE CHANGES, WHAT OTHER SIGNIFICANT LANGUAGE CHANGES ARE PROPOSED FOR RATE SCHEDULE NO. 38?

A. EPE is proposing to increase the interruptible capacity to 100 MW, from the current 75 MW, by opening the rate schedule to new customers until such load level is achieved. Also, the General Conditions are revised to indicate that interruptions can be called for economic and for system operational conditions, in addition to emergency conditions. No other significant language changes are proposed for this rate schedule.

Q141. WHY IS EPE PROPOSING TO EXPAND THE REASONS FOR WHICH AN INTERRUPTION CAN BE CALLED?

A. While this expansion is not expected to result in a marked increase in interruptions and the existing limits on the number and period of interruptions is not proposed to be changed, this change would make the interruptible service more useful in managing EPE's system.

Q142. HOW ARE THE RATE SCHEDULE NO. 38 DEMAND AND ENERGY CHARGES CALCULATED?

A. Rate Schedule No. 38 Demand and Energy Charges were designed based on demand and energy costs allocated to the Rate Schedule No. 25 Large Power Service rate class. The Demand Charge is calculated by reducing the Rate Schedule No. 25 voltage-differentiated demand-related costs to account for avoided incremental capacity costs. The Energy Charge is set equal to the Rate Schedule No. 25 Off-Peak Period Energy Charge.

EPE proposes to continue to move existing Interruptible demand charges towards full cost level. Therefore, a rate moderation adjustment is made that provides a credit that is higher than EPE's incremental capacity cost. This rate moderation adjustment has been used in designing interruptible service rates by EPE in other recently filed rate cases in both Texas and New Mexico.

Q143. IS RATE SCHEDULE NO. 38 CONSIDERED A DISCOUNT RATE PURSUANT TO PURA SECTION 36.007?

A. No. Rate Schedule No. 38 - Notice Interruptible Service is specifically for interruptible service, not to provide discounted firm service.

Q144. WHAT IS THE IMPACT ON EXISTING NOTICED INTERRUPTIBLE CUSTOMERS OF THE CHANGES EPE IS PROPOSING?

A. The combination of the increase in the Rate Schedule No. 38 Demand Charge and decrease in the Energy Charge results in an overall base-rate revenue impact to non-firm service nearly equivalent to EPE's system average increase proposed in this rate case. The net impact of the changes in interruptible rates is a function of the customer's firm and non-firm service level and the proposed changes in the rate schedule applicable to the customer's firm service.

Q. Schedule No. 41 – City and County Service

Q145. PLEASE DESCRIBE THE EXISTING RATE SCHEDULE NO. 41 – CITY AND COUNTY SERVICE RATE.

A. Rate Schedule No. 41 is closed to new service applications as of July 30, 2010. This rate schedule is applicable to public schools and for municipal and county service. The rate schedule includes two monthly rate options: a Standard Service Rate and an Alternative TOD Rate. A clause offers customers that elect to take service under the Alternative TOD Rate the ability to revert to the Standard Service Rate after an initial twelve-month period under the Alternative TOD Rate.

Other provisions currently included under Rate Schedule No. 41 is a TES Rider, Non-Metered Service for instances when metering of energy is impractical due to very low monthly usage, a power factor adjustment (although such charges are effectively suspended until new rates from this rate case are implemented), and a meter voltage adjustment applicable for certain customers. It also includes reference to other applicable riders, as well as terms and conditions that apply to service under this schedule.

Q146. PLEASE DESCRIBE THE EXISTING STRUCTURE OF THE RATES OFFERED UNDER RATE SCHEDULE NO. 41.

A. The Standard Service Rate structure consists of a monthly Customer Charge, seasonal Demand Charges, and declining two-block Energy Charges (differentiated by primary and secondary service voltage). The Demand Charges apply to billed kW that is more than 15 kW. Energy charges are applicable in a declining block structure, with energy exceeding 3,000 kWh charged at a substantially lower rate than the initial block. The summer Demand and summer Energy charges apply in the months of June through September.

The Alternative TOD Rate consists of a monthly Customer Charge, seasonal Demand Charges, and Energy Charges that apply based on the month, day, and hour that usage occurs. The summer Demand and summer Energy Charges apply in the months of June through September. The On-Peak Period Energy Charge applies from noon to 6:00 P.M., weekdays during the summer period, and the Off-Peak Period Energy Charge applies during all other hours.

Q147. OTHER THAN THE BROADLY APPLICABLE LANGUAGE CHANGES, WHAT OTHER SIGNIFICANT LANGUAGE CHANGES ARE PROPOSED FOR RATE SCHEDULE NO. 41?

A. EPE is proposing to implement a Reserved Distribution Capacity Service Charge, as discussed earlier in this section of the testimony, which will be billed to customers that request back-up for their primary voltage loads. Also, as agreed in stipulation in the 2021 Rate Case, EPE is proposing to remove the crediting clause for charges under the power factor adjustment provision. No other significant language changes are proposed for this rate schedule.

Q148. WHAT CHANGES DOES EPE PROPOSE FOR RATE SCHEDULE NO. 41 RATES AND RATE STRUCTURES?

A. For the Standard Service Rate, EPE is proposing to

(1) set the monthly Customer Charge to collect all the customer-related costs; and

(2) increase the price differential between summer and non-summer Demand Charges; and

(3) eliminate the declining block Energy Charge structure and replace it with a flat Energy Charge.

For the Alternative TOD Rate, EPE is proposing to:

(1) set the monthly Customer Charge equal to the Standard Service Rate Monthly Customer Charge;

(2) set the Demand Charges equal to the Standard Service Rate Demand Charges; and

(3) to the extent possible, increase the price differential between On-Peak Period and Off-Peak Period summer Energy Charges.

Q149. WHY IS THE COMPANY PROPOSING TO ELIMINATE THE DECLINING BLOCK ENERGY CHARGE STRUCTURE OF RATE SCHEDULE NO. 41?

A. Declining-block rate structures, where the per unit rate for energy decreases as customers use more energy, are legacy rate structures that are no longer generally accepted because they send price signals that may encourage consumption and discourage conservation.

R. Schedule No. 99 – Miscellaneous Service Charges

Q150. PLEASE DESCRIBE THE EXISTING RATE SCHEDULE NO. 99 – MISCELLANEOUS SERVICE CHARGES.

A. Rate Schedule No. 99 – Miscellaneous Service Charges is applicable to all customers and lists charges and fees for services performed by EPE that are not at the core of its utility service (e.g., generation/procurement of power, transmission and distribution of the power, metering and billing, administrative support of these functions).

Q151. IS EPE SEEKING A CHANGE TO ANY OF THE CHARGES FOUND IN ITS RATE SCHEDULE NO. 99?

A. Yes. Please refer to the direct testimony of EPE witness Rene Gonzalez for discussion of the changes to this schedule for the activity-based charges. EPE is also proposing to add a Facilities Plus Rental Charge and a Transmission Facilities Charge which will provide for recovery of and on the Company's investment in infrastructure, particularly substations, which is specifically built and dedicated to serve the requesting customer. The expectation is to apply the Facilities Plus Rental Charge to subtransmission and primary voltage customers and the Transmission Facilities charge to customers with connected loads equal to or exceeding 69 kV.

S. Schedule No. CS - Community Solar Service

Q152. PLEASE DESCRIBE THE EXISTING RATE SCHEDULE NO. CS – COMMUNITY SOLAR RATE.

A. This rate schedule is available to customers without distributed generation and that take service under the retail service rate schedule listed in the Monthly Rate section of Schedule No. CS. Participating customers pay a subscription price for their capacity, which is based on the cost of the Community Solar facility and receive a credit for the quantity of energy produced by their subscribed capacity based on their qualifying retail service generation credit rate.

Provisions currently included under Rate Schedule No. CS are a Type of Service provision, which details length of subscription terms and capacity minimums and maximums; describes the determination of solar billing energy; the early termination of the Community Solar program. It also includes other terms and conditions that apply to service under this schedule.

Q153. PLEASE DESCRIBE THE EXISTING RATE STRUCTURE OF RATE SCHEDULE NO. CS.

A. The rate structure consists of a Monthly Capacity Charge, which is applied on a per kW basis of capacity subscribed, and a System Generation Credit, which is applied on a per kWh basis and varies among the listed retail service schedules. Qualifying low-income subscribers pay a reduced Monthly Capacity Charge.

Q154. HOW DID EPE DETERMINE THE SUBSCRIPTION PRICE THAT SUBSCRIBERS WILL PAY?

A. The subscription price for solar capacity produced by the Community Solar facilities is based on the cost to EPE of the three-MW Montana power station community solar facility, the two-MW purchased power agreement associated with the PSEG solar energy center, and the recently added ten-MW San Elizario community solar facility.

For details on the calculation of the current subscription price, please reference the documents filed in Docket No. 54403.[10]

Q155. IS EPE PROPOSING CHANGES TO THE SUBSCRIPTION PRICE?

A. No. EPE is not proposing to modify the Community Solar subscription price in this case. The prior subscription price, however, which recently expired with the commercial operation of the new ten-MW San Elizario solar facility, is deleted from the proposed rate schedule.

Q156. WHAT IS A SYSTEM GENERATION CREDIT?

A. The System Generation Credit used to calculate the credit provided to participating Community Solar program subscribers consists of two components: a base rate and a fuel rate. The base rate component is derived from the revenue requirements established in the rate case proceedings and reflects the direct non-fuel unit cost of EPE's system generation resources and varies between rate classes. The fuel rate component is equal to the applicable fuel factor which, as proposed in the current filing, will be provided in Rate Schedule No. 98 – Fuel Adjustment Factor.

Q157. WILL THE BASE RATE COMPONENT OF THE SYSTEM GENERATION CREDIT RATE CHANGE OVER TIME?

A. Yes. That component of the System Generation Credit will be revised whenever EPE changes rates in a general rate case proceeding or significantly adds solar resources.

Q158. IS EPE PROPOSING CHANGES TO THE BASE RATE COMPONENT IN THIS PROCEEDING?

A. Yes. EPE proposes to update the base rate component for 1) the allocated production costs

[10] *Application of El Paso Electric Company for a 10 MW Community Solar Expansion and Authority to Modify Schedule No. CS Community Solar Rate*, Docket No. 54403, Order (September 14, 2023).

as determined in the current filing, and 2) a modified methodology to calculate the generation credit.

The proposed base rate component of the System Generation Credit of the qualifying rate schedules are listed in the table below, and the rate calculations are in rate design workpapers.

Table MC- 2

Retail Service Schedule	**Per kWh**
Schedule No. 01 – Residential Service	\$−0.060305
Schedule No. 02 – Small General Service	\$−0.054710
Schedule No. 24 – General Service (Closed)	\$−0.043481

Q159. PLEASE DESCRIBE THE MODIFIED METHODOLOGY TO CALCULATE THE GENERATION CREDIT.

A. The proposed methodology is consistent with that used in EPE's recently filed Texas Business Solar Power Program application.[11] In that methodology, production function costs which were allocated using the D1PROD and the D2PROD allocation factor were included in the generation credit at 100% and at 43%, respectively. The 43% applied to D2PROD allocated production function costs is based on the expected effective load carry capability ("ELCC") of EPE's existing solar resources plus EPE's new 150 MW solar photovoltaic generation facility, called Texas Solar One. The ELCC is used to credit non-dispatchable resources for the amount they contribute toward system resource adequacy. As more solar is added to system resources, peak-shifting will occur to hours when solar production is reduced, resulting in a decrease in the ELCC and thus reducing the System Generation Credit rate.

As discussed in the testimony of EPE witness Hernandez, EPE is proposing to use three production cost allocation factors, namely D1PROD, D2PROD, and the new DPROD12. DPROD12 is used to assign demand related costs of EPE's base load generation, D2PROD for assigning demand related costs of peaking generation facilities, and D1PROD for assigning demand related costs of all other generation facilities.

[11] *Application of El Paso Electric Company to Implement a Voluntary Texas Business Solar Power Program,* Docket No. 55176, Filed June 26, 2023.

To calculate the generation credit in this filing, is proposing to apply the ELCC factor to the D1PROD and D2PROD allocated production costs, which include EPE peaking and load following generating units. The ELCC factor of EPE's existing solar resources, however, is 49% and is the value applied to the test year production costs.

Q160. HOW DOES EPE RECOVER AMOUNTS PROVIDED TO SUBSCRIBERS VIA THE BASE RATE COMPONENT OF THE SYSTEM GENERATION CREDIT?

A. The amounts provided to subscribers is recovered through the base rates of each of the retail rate schedules that are listed in Rate Schedule No. CS.

Q161. IS EPE PROPOSING ANY OTHER CHANGES TO THE COMMUNITY SOLAR RATE SCHEDULE?

A. Yes. EPE proposes to add language to clarify that EPE has the right to suspend both the subscription charges and the generation credits if the facility is taken out of service for an extended period or suspend the subscription of some subscribers if one of the dedicated solar facilities is experiencing difficulties that essentially derate the capacity.

T. Schedule No. TXBSP – Texas Business Solar Power Rate

Q162. PLEASE DESCRIBE THE EXISTING RATE SCHEDULE NO. TXBSP – TEXAS BUSINESS SOLAR POWER RATE.

A. This rate schedule is available to larger load customers without distributed generation and that take service under the retail service rate schedule listed in the Monthly Rate section of Schedule No. TXBSP. Participating customers pay a subscription price for their capacity, which is based on the cost of the Texas Solar One facility, EPE's new 150 MW solar photovoltaic generation facility, and receive a credit for the quantity of energy produced by their subscribed capacity based on their qualifying retail service generation credit rate.

Provisions currently included under Rate Schedule No. TXBSP are a Type of Service provision, which details length of subscription terms and capacity minimums and maximums; describes the determination of solar billing energy; the early termination of the Texas Business Solar Program (TXBSP). It also includes other terms and conditions that apply to service under this schedule.

Q163. PLEASE DESCRIBE THE EXISTING RATE STRUCTURE OF RATE SCHEDULE NO. TXBSP.

A. The rate structure consists of a monthly Solar Capacity Charge, which is applied on a per kW basis of capacity subscribed, and a Solar Generation Credit, which is applied on a per kWh basis and varies among the listed retail service schedules.

Q164. HOW DID EPE DETERMINE THE SUBSCRIPTION PRICE THAT SUBSCRIBERS WILL PAY?

A. The subscription price for solar capacity produced by the TXBSP facility is based on the cost to EPE of the 150 MW Texas Solar One facility. Fifty MW of that facility is dedicated to TXBSP.

For details on the calculation of the current subscription price, please reference the documents filed in Docket No. 55176.[12]

Q165. IS EPE PROPOSING CHANGES TO THE SUBSCRIPTION PRICE?

A. No. EPE is not proposing to modify the TXBSP subscription price in this case.

Q166. WHAT IS A SOLAR GENERATION CREDIT?

A. Like the System Generation Credit of Rate Schedule No. CS, the Solar Generation Credit is used to calculate the credit provided to participating TXBSP program subscribers consists of two components: a base rate and a fuel rate. The base rate component is derived from the revenue requirements established in the rate case proceedings and reflects the direct non-fuel unit cost of EPE's system generation resources and varies between rate classes. The fuel rate component is equal to the applicable fuel factor which, as proposed in the current filing, will be provided in Rate Schedule No. 98 – Fuel Adjustment Factor.

Q167. WILL THE BASE RATE COMPONENT OF THE SOLAR GENERATION CREDIT RATE CHANGE OVER TIME?

[12] *Application of El Paso Electric Company to Implement a Voluntary Texas Business Solar Power Program*, Docket No. 55176, Filed June 26, 2023.

A. Yes. That component of the System Generation Credit will be revised whenever EPE changes rates in a general rate case proceeding or significantly adds solar resources.

Q168. IS EPE PROPOSING CHANGES TO THE BASE RATE COMPONENT IN THIS PROCEEDING?

A. Yes. As described above for Rate Schedule No. CS, EPE is proposing to update this rate schedule's base rate component for 1) the allocated production costs as determined in the current filing, and 2) a modified methodology to calculate the generation credit.

The proposed base rate component of the Solar Generation Credit of the qualifying rate schedules are listed in the table below, and the rate calculations are in rate design workpapers.

Table MC- 3

Retail Service Schedule	**Per kWh**
Schedule No. 24 – General Service	$−0.043481
Schedule No. 02 – Small General Service	$−0.040268
Schedule No. 24 – General Service (Closed)	$−0.055291

Q169. HOW DOES EPE RECOVER AMOUNTS PROVIDED TO SUBSCRIBERS VIA THE BASE RATE COMPONENT OF THE SOLAR GENERATION CREDIT?

A. The amounts provided to subscribers is recovered through the base rates of each of the retail rate schedules that are listed in Rate Schedule No. TXBSP.

Q170. IS EPE PROPOSING ANY OTHER CHANGES TO THE TEXAS BUSINESS SOLAR POWER RATE TARIFF?

A. No other changes are proposed for this rate schedule.

U. Schedule No. EVC - Electric Vehicle Charging

Q171. PLEASE DESCRIBE THE EXISTING RATE SCHEDULE NO. EVC - ELECTRIC VEHICLE CHARGING RATE.

A. This rate schedule is available, on a voluntary basis, to residential and commercial customers that have a separately metered facility dedicated solely for the charging of electric vehicles and only for charging activity operating at 120 volts ("V") or up to 480V.

The rate schedule consists of a single rate option corresponding to the retail rate schedule that, but for the taking of service under Schedule No. EVC, the consumption for electric vehicle ("EV") charging would have billed under. It also includes provisions for determination of billing demand and that reference other applicable riders, as well as terms and conditions that apply to service under this schedule.

Q172. PLEASE DESCRIBE THE EXISTING RATE STRUCTURE OF RATE SCHEDULE NO. EVC.

A. The rate structure consists of a monthly Customer Charge, a seasonal Demand Charge, and a TOD Energy Charge. The summer Demand and summer Energy Charges apply in the months of June through September. Unlike the rate structure of EPE's most other TOD rate options, the TOD Energy Charge of Schedule No. EVC has three pricing periods: on-peak, off-peak, and super off-peak. The On-Peak Period Energy Charge applies from noon to 6:00 P.M., weekdays during the summer period, the Super Off-Peak Period Energy Charge applies from 12:00 A.M. through 8:00 A.M., year-round in all days, and the Off-Peak Period Energy Charge applies during all other hours.

The Demand Charge is applicable only to 480V EV chargers. If the maximum demand of those 480V EV chargers is measured during the Super Off-Peak Period, then the Super Off-Peak Period Demand Charge applies. Otherwise, applicable seasonal Demand Charge is used for billing purposes.

Q173. OTHER THAN THE BROADLY APPLICABLE LANGUAGE CHANGES, WHAT OTHER SIGNIFICANT LANGUAGE CHANGES ARE PROPOSED FOR RATE SCHEDULE NO. EVC?

A. The charging activity operating voltage limitations are eliminated. Also, dedicated storage and photovoltaic facilities associated solely with the EV charging facility is considered eligible for service under this rate schedule. Additionally, the applicability of the demand charge based on voltage level is replaced with measured kW load, i.e., 20 kW or greater for the smaller customers and 50 kW or greater for the larger customers.

Q174. WHAT CHANGES DOES EPE PROPOSE FOR RATE SCHEDULE NO. EVC RATES AND RATE STRUCTURES?

A. The proposed monthly Customer Charge will fully include the costs related to meters, services drops, and meter reading, which are the most relevant incremental customer-related cost to provide this service and to avoid the duplication in the recovery of other customer-related costs paid by customers through their otherwise applicable rate schedule.[13]

Also, because of EPE's investment in its distribution system, listed retail rates No. 01 and 02 will now include a demand charge component to contribute toward the recovery of and on that investment which enables high load EV charging under these retail rates. Consistent with the design of the demand charge of the other listed retail rates in the schedule, the demand charge for rates No. 01 and 02 is based on distribution-related costs as determined in the CCOS.

Q175. WHY SHOULD STORAGE AND PHOTOVOLTAIC FACILITIES ASSOCIATED WITH THE EV CHARGING BE ALLOWED TO CONNECT BEHIND THE METER AND BE CONSIDERED AS PART OF THE EV CHARGING LIMITATION OF THIS RATE SCHEDULE?

A. Allowing customers to have EV charging equipment, solar and batteries to be connected to the same utility meter offers benefits for both the customer and the electric grid. By integrating solar carports and batteries with EV charging systems, customers can optimize their energy use and manage demand. It also allows for reduction of EV charging grid impacts, where solar carports and batteries can help alleviate strain on the grid by reducing the amount of energy EV charging is pulling from it, which is especially beneficial during peak hours.

Q176. EXPLAIN EPE'S RATIONALE TO MAKE THE APPLICATION OF THE DEMAND CHARGE BASED ON SERVICE LOAD (KW) INSTEAD OF EQUIPMENT SIZE

[13] Since sales under Rate Schedule No. EVC have not arisen to a level significant enough to establish it as a rate class, there is no cost allocation to this rate schedule. In subsequent rate cases, EPE expects to be able to more accurately allocate and assign costs to this new tariff as load and consumption information becomes available. EPE uses the costs applicable to Rate Schedule No. 02 to derive the Schedule EVC Customer Charge for the listed Retail Rate Nos. 02, 24, 25, and 41.

(VOLTAGE)?

A. Kilowatts reflect real EV charging power consumption which is the key factor for calculating energy consumption and setting rates. Voltage, on the other hand, does not directly indicate how much energy is being consumed by the EV charger. Two EV charging stations operating at the same voltage may consume vastly different amounts of power depending on their amperage and efficiency, so charging rates based on voltage alone would not reflect the true grid impact.

It is also important to have a rate schedule that is standardized across various types of charging equipment. Currently the rate is encouraging customers to install Level 2 charging instead of DC fast charging. This is because Level 2 chargers are typically connected at voltages of 240V/208V, thus helping the customer avoid paying demand charges, even if the connected EV load is quite significant. By having a kW demand threshold, means that both Level 2 installs and DC fast installs can be subject to demand charges. In addition, most of other EPE rate schedules are based on kW limitation, which is another reason EPE is proposing this change which will allow us to be more consistent and the rate will be easier for customers to understand.

Q177. WHAT IS THE IMPACT TO CUSTOMERS SERVED UNDER RATE SCHEDULE NO. EVC IF THE APPLICABILITY OF THE DEMAND CHARGE IS REVISED AS PROPOSED?

A. EPE is estimating that only one residential and two non-residential customers that are currently on EVC rate would be impacted by this rate change. Those would be the customers with total load of over the kW threshold, operating at voltage less than 480V. To mitigate the impact of the proposed demand charge to any retail rates No. 01 and 02 customer that is currently on Rate Schedule No. EVC, EPE will defer applying demand charges to their bills until the effective date of this rate schedule in a subsequent rate case filing.

VI. Other Rate Schedules

Q178. IS EPE SEEKING A CHANGE TO ANY OTHER RATE SCHEDULES?

A. Yes. Some rate schedules will be revised substantively while others will have minor changes. Other rate schedules are proposed to be eliminated while some rate schedules are added to EPE's tariff. Below is discussion of these changes.

Q179. PLEASE DESCRIBE THE COGENERATION AND SMALL POWER PRODUCTION FACILITIES SCHEDULES AND EPE'S PROPOSED CHANGES TO THESE RATE SCHEDULES.

A. As required by 18 C.F.R. § 292.305(b), EPE provides services to qualifying facilities under these rate schedules:

- Rate Schedule No. 45 – Supplementary Power, for energy and capacity by EPE in addition to the energy and capacity supplied by a qualifying facility. The supplementary power service rates are the retail rates applicable to a customer having power requirements equal to the supplementary power requirements of the qualifying facility.
- Rate Schedule No. 46 – Maintenance Power, for energy and capacity supplied by EPE, during scheduled outages of a qualifying facility, to replace energy and capacity ordinarily supplied by the qualifying facility. The maintenance power service rates are the retail rates applicable to a customer absent its qualifying facility's generation. A demand ratchet, however, does not apply to this service.
- Rate Schedule No. 47 – Back-up Power, for energy and capacity supplied by EPE during an unscheduled outage of a qualifying facility to replace energy and capacity ordinarily supplied by the qualifying facility. The back-up power service rates are the retail rates applicable to a customer absent its qualifying facility's generation. Demand ratchets or power factor penalties, however, do not apply to this service.
- Rate Schedule No. 51 – Interruptible Power, for energy and capacity supplied by EPE that is subject to interruption by the Company under specified conditions. The interruptible power service rates are the retail rates applicable to a customer absent its qualifying facility's generation.

EPE proposes to only revise the delivery service charges and interconnection charges in the rate schedules, as shown in Exhibit MC-3.

Q180. HOW MANY CUSTOMERS CURRENTLY RECEIVE SERVICE UNDER THE SUPPLEMENTARY POWER SERVICE, BACKUP POWER SERVICE,

MAINTENANCE POWER SERVICE OR INTERRUPTIBLE POWER SERVICE RATE SCHEDULES?

A. None.

Q181. PLEASE DESCRIBE RATE SCHEDULE NO. 48 – NON-FIRM PURCHASED POWER SERVICE FROM DISTRIBUTED GENERATORS, DISTRIBUTED RENEWABLE GENERATORS, AND QUALIFYING FACILITIES AND EPE'S PROPOSED CHANGES TO THIS RATE SCHEDULE.

A. Rate Schedule No. 48 provides for energy purchases by EPE from customers who operate qualifying generation in parallel with EPE's system. A Standard Interconnection Agreement is required. The rate schedule provides for two alternative metering and energy payment options, depending on the generating capacity (in kW) of the qualifying facility, and includes a monthly customer charge which varies with the energy payment option elected.

EPE proposes to revise the rate schedule's interconnection charges, as shown in Exhibit MC-3.

Q182. PLEASE DESCRIBE RATE SCHEDULE NO. 49 – STATE UNIVERSITY DISCOUNT RATE RIDER AND EPE'S PROPOSED CHANGES TO THIS RATE SCHEDULE.

A. Rate Schedule No. 49 is a rate schedule required by PURA § 36.351. The rate schedule provides a 20% discount from the base charges of any four-year state university or upper-level institution.

Minor clarification language is proposed to be added to the rate schedule regarding what is considered a base charge that is included in determination of the discount and what is not.

Q183. PLEASE DESCRIBE RATE SCHEDULE NO. 95 – MILITARY BASE-RATE DISCOUNT AND EPE'S PROPOSED CHANGES TO THIS RATE SCHEDULE.

A. Rate Schedule No. 95 is a rate schedule required by PURA § 36.354. The rate schedule provides a 20% discount from the base charges of federal military bases.

Minor clarification language is proposed to be added to the rate schedule regarding what is considered a base charge that is included in determination of the discount and what is not.

Q184. PLEASE DESCRIBE RATE SCHEDULE NO. 98 – FUEL ADJUSTMENT FACTOR AND EPE'S PROPOSED CHANGES TO THIS RATE SCHEDULE.

A. Rate Schedule No. 98 is currently EPE' Fixed Fuel Factor rate schedule but is proposed to be retitled to Fuel Adjustment Factor so that the change in fuel formula described by EPE witness Reza can be implemented. The current version of Rate Schedule No. 98 lists the fixed fuel factors, in $ per kWh, differentiated by voltage level, and calculated in compliance with the Commission-approved fuel factor formula from Docket No. 37690.

The proposed version of the rate schedule will simply provide the formula that will used to determine a fuel adjustment factor each month. This fuel adjustment factor will also be in $ per kWh and voltage differentiated.

Q185. PLEASE DESCRIBE RATE SCHEDULE NO. AMS – ADVANCED METERING SYSTEM SURCHARGE AND EPE'S PROPOSED CHANGES TO THIS RATE SCHEDULE.

A. Rate Schedule No. AMS is, which was approved in EPE's advanced metering system ("AMS") proceeding, Docket No. 52040, recovers the Company's costs incurred to deploy an AMS. The rate schedule is intended to be in effect for twelve years and the factors are subject to a reconciliation proceeding in the future.

As explain in the direct testimony of EPE witness Hernandez in this proceeding, the Company is proposing to remove a significant proportion of operational cost savings that are included in the surcharge calculation because most of those savings are reflected in the Test Year expenses in this proceeding. The proposed Rate Schedule AMS incorporates the removal of these cost savings, which resulted in a slight increase in the surcharge factors.

Q186. PLEASE DESCRIBE RATE SCHEDULE NO. DCRF – DISTRIBUTION COST RECOVERY FACTOR AND EPE'S PROPOSED CHANGES TO THIS RATE SCHEDULE.

A. Rate Schedule No. DCRF provides interim recovery of the Company's investment in its distribution grid system, pursuant to the requirements of 16 TAC § 25.243. The Test Year revenue requirements in this proceeding now include all the distribution system investment and are embedded in the proposed base rates.

EPE proposes to reset all values shown in this rate schedule to zero and include it in the RFP Schedule Q-8.8.

Q187. PLEASE DESCRIBE RATE SCHEDULE NO. GCRR – GENERATION COST RECOVERY FACTOR AND EPE'S PROPOSED CHANGES TO THIS RATE SCHEDULE.

A. Rate Schedule No. GCRR provides interim recovery of the Company's investment in its a power generation facility, pursuant to the requirements of 16 TAC § 25.248. The Test Year revenue requirements in this proceeding now include all power generation facility investments and are embedded in the proposed base rates.

EPE proposes to reset all values shown in this rate schedule to zero and include it in the RFP Schedule Q-8.8.

Q188. PLEASE DESCRIBE RATE SCHEDULE NO. RPRF – RETIRING PLANT RIDER FACTOR AND EPE'S PROPOSED CHANGES TO THIS RATE SCHEDULE.

A. Rate Schedule No. RPRF was established in EPE's last rate case to provide interim recovery of the Company's investment and operating costs in three generating units that had been scheduled for retirement in 2022 (Newman Units 1 and 2 and Rio Grande 7). The Test Year revenue requirements of those three units was removed from the base rate revenue requirement and were recovered through this rider. As each unit ceased to operate, the factors in this schedule were to be adjusted downward to recognize that the unit was no longer serving Texas ratepayers.

Since these three units have not ceased operations, but are still eligible for retirement, EPE proposes to update the revenue requirement of each unit, calculate new factors for the rate schedule, and include it in the RFP Schedule Q8.8. EPE is proposing to also include the revenue requirement associated with Rio Grande 6 in Rate Schedule RPRF, which is limited to Operations and Maintenance expense. Please refer to the direct testimony of EPE witness Rodriguez for discussion of how each of these four units are intended to continue to provide service to customers and EPE's expectation for retirement and abandonment of them. EPE witness Hernandez prepared an exhibit outlining the revenue requirement per unit. Exhibit MC-5 provides the calculation of the proposed Schedule RPRF factors based on each unit's revenue requirement.

Q189. PLEASE DESCRIBE RATE SCHEDULE NO. GEP – GREEN ENERGY PLUS AND WHY EPE IS PROPOSING THIS NEW RATE SCHEDULE.

A. On July 26, 2023, EPE filed with the City of El Paso its request to implement Rate Schedule No. GEP-A – Green Energy Plus (Cities), a voluntary program, to provide customers that operate within the city limits of El Paso and that wish to receive all or part of their electricity from renewable energy facilities located in or that deliver energy to EPE's balancing area that are either owned by EPE or under a purchased power agreement (PPA) with EPE. The Rate Schedule No. GEP-A application that was filed at the City of El Paso City Clerk's Office and the City Council approved the as filed Rate Schedule No. GEP-A, which is currently in effect within the City of El Paso corporate limits. The proposed Rate Schedule No. GEP, which contains all the provisions of Schedule No. GEP-A, is applicable in EPE's entire Texas service territory and is proposed to supersede Rate Schedule No. GEP-A.

Rate Schedule No. GEP provides two options for customers – a full "Buy-all / Sell-all" or "Virtual Load netting." Customers selecting the first option purchase all of their retail requirements, the metered consumption at their site, from EPE based on tariffed rates and "sell" all of the renewable energy they purchase under a separate Renewable Energy Contract to EPE at an agreed price. If the customer elects Virtual Load Netting, the output of their contracted renewable energy resource is netted "virtually" against their contemporaneous metered site load. The resulting net energy and demand are billed under the applicable retail tariff and any excess renewable output is purchased by EPE at avoided cost.

Q190. DO THE ENERGY PURCHASES TAKING PLACE UNDER THE GREEN ENERGY PLUS RATE SCHEDULE IMPACT OTHER CUSTOMERS?

A. No. All of the energy supplied by renewable resources procured for purposes of the GEP rate schedule are purchased by the participating customer and either (1) offset the load requirements of the participant or (2) are supplied to other retail customers at EPE's avoided cost. Because the energy is provided to retail customers at EPE's avoided costs, there is no financial impact to non-participants. In other words, because the power is priced at what EPE customers would otherwise pay for power if the power from the facility or PPA under the GEP rate schedule had not been provided, other customers are indifferent to the source of the energy exported to the system.

Q191. WHICH RATE SCHEDULES IS EPE NOT PROPOSING MAKING ANY CHANGES TO?

A. EPE is submitting the following rate schedules as part of its entire tariff, but with no proposed changes to the language or rates of the currently effective rate schedules:

- Rate Schedule No. DG – Interconnection And Parallel Operation of Distributed Generation; and
- Rate Schedule No. 33 – Economic Development Rate Rider

Q192. DOES RFP SCHEDULE Q-8.8 CONTAIN EPE'S ENTIRE TARIFF PROPOSED IN THIS PROCEEDING?

A. Yes. RFP Schedule Q-8.8 is EPE's entire tariff requested for the Commission's approval in this proceeding. Some rate schedules, such as Rate Schedule No. 97 – Energy Efficiency Cost Recovery Factor or Rate Schedule No. EADIT – Excess Accumulated Deferred Income Tax Credit Factor or Rate Schedule No. COVID-19 – Project No. 50664 Asset Surcharge, are not included because those are dealt with in separate proceedings.

Q193. WHAT IS THE REQUESTED EFFECTIVE DATE OF THE PROPOSED TARIFF?

A. EPE is requesting an effective date of July 1, 2025, for its proposed tariff, which is 155 days from the filing of EPE's application in this proceeding.

VII. Peak Time Rebate Pilot Program

Q194. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?

A. In this section of my testimony, I discuss EPE's proposal to implement the Peak Time Rebate Pilot Program, which will provide those customers that participate in the program the opportunity to receive a bill credit for reducing energy consumption during a designated peak period following a notification from EPE. The program will consist of recruitment of participants, implementing and processing the rebates through the billing process, and evaluating the results.

Q195. WHY IS EPE PROPOSING THIS PILOT PROGRAM SEPARATELY FROM THE TIME VARYING PILOT PROGRAM THAT EPE AND THE BRATTLE GROUP DEVELOPED?

A. In developing the rate treatments for piloting in the TVR pilot, EPE and Brattle determined that a Critical Peak Pricing option was more appropriately included given its greater complexity. EPE elected instead to pilot PTR in this case in order to limit the number of rate treatments included in the TVR pilot.

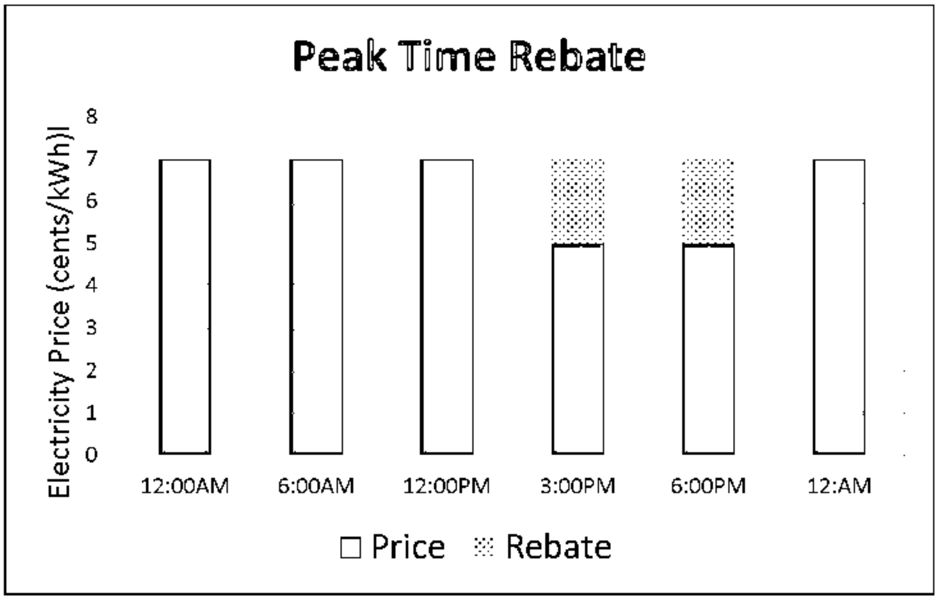
Q196. HOW WILL THE BILL CREDIT BE CALCULATED?

A. The bill credit will be calculated by comparing a customer's actual electricity usage during a Peak Time Rebate (PTR) event to their baseline usage, which reflects their typical consumption on similar non-PTR event days. The customer will earn a bill credit based on the difference between their baseline and their usage over the event, multiplied by the credit rate per kilowatt-hour. Refer to Figure MC-1 below, which shows a simple example of the electricity price drop from 7 cents per kWh to 5 cents per kWh in the afternoon hours due to the PTR credit.

Q197. WILL THE PARTICIPATING CUSTOMER BE PENALIZED IF THEY FAIL TO REDUCE THEIR USAGE OR EVEN INCREASE USAGE DURING THE EVENT PERIOD?

A. No. Participating customers who do not perform during event periods with consumption lower than their baseline will not receive any credit for the event but will not be penalized.

Figure MC-1:



Q198. WHAT IS THE BASIS FOR THE REBATE RATE?

A. For the pilot program, the basis for the rebate (described as the PTR Credit in the proposed rate schedule) will be EPE's estimated avoided cost of energy, filed each February in pursuant to § 25.24(e)(2)(A).

Q199. HOW WILL EPE RECOVER THE AMOUNT OF REBATES PROVIDED TO PARTICIPATING CUSTOMERS AND THE COST OF ADMINISTERING THE PROGRAM?

A. The amount of the rebates provided to participating customers will be included in the determination of EPE's monthly fuel charge, as it will be recorded as cost of fuel and purchased power.

EPE intends to track the costs of administering the Peak Time Rebate Pilot and if any portion of those costs are incurred during a rate case test year, request cost recovery in that rate case.

Q200. HOW LONG DOES EPE INTEND TO PILOT THIS PROGRAM?

A. The program must encompass an entire summer period, June through September, within a calendar year. Several months of preparation for implementation of the business processes,