EL PASO ELECTRIC COMPANY

Line Extension Policy and Construction Charges

I. RENTAL OF COMPANY EQUIPMENT

The Company will rent certain equipment to Customers on a short-term, emergency basis, provided the items of equipment are not immediately available from local suppliers~~,~~ and the Company has a sufficient supply of such items in stock to meet its operating requirements. The terms and conditions of the rental transaction shall be specified in writing

EL PASO ELECTRIC COMPANY

Line Extension Policy and Construction Charges

J. SALE OF COMPANY INSTALLED FACILITIES

The Company, in response to a Customer request, may sell Company facilities, in place, as is, for the estimated replacement cost less depreciation on replacement cost, if:

(1) The facilities are solely for the purpose of serving the Customer, and

(2) The Customer is changing or expanding the Customer's electrical facilities in a manner that will include the Company's facilities as an integral part of the Customer's facilities.

EL PASO ELECTRIC COMPANY

Line Extension Policy and Construction Charges

K. IMPAIRED LINE CLEARANCE

~~Any Customer (person, company, corporation, partnership, contractor, land developer, property owner, or property lease, or any combination thereof)~~Any Customer who installs or constructs any permanent or temporary structure(s) that constitutes an Impaired Clearance of the Company's existing transmission, substation, express, feeder, street light or distribution line facilities, or any combination thereof, shall bear all costs incurred by the Company in the reconstruction or relocation, or both, necessary to remove any and all Impaired Clearances. The Customer shall notify the Company as soon as possible of any existing or anticipated Impaired Clearances. In accordance with Section 2.III.4 c., of the Company's Texas Rules and Regulations approved by the Public Utility Commission of Texas (PUCT), the Company may discontinue utility service to a customer without prior notice in the event of a condition determined by the Company to be hazardous.

DOCKET NO. _____

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

DIRECT TESTIMONY

OF

GEORGE NOVELA

FOR

EL PASO ELECTRIC COMPANY

JUNE 2021

EXECUTIVE SUMMARY

George Novela is the Director of Economic and Rate Research at El Paso Electric Company ("EPE" or "Company"). In his testimony, he describes EPE's load studies and supports EPE's weather normalization adjustment. He also describes and supports EPE's 2021 long-term energy and demand forecast.

Load studies are used in support of a number of functions including allocation of sales among rate classes and jurisdictions, rate studies, class contribution to peak, load factor analysis, cost allocation, etc. Mr. Novela's testimony describes the load research process used to collect and summarize load study data. His testimony further addresses how sales and demand are allocated by class, voltage, and jurisdiction. The testimony also discusses the use of loss factors to reconcile the native energy used by retail and wholesale customers to the amount of electricity delivered to the system by EPE generation units and purchased power.

This testimony describes the weather patterns in both Las Cruces, New Mexico, and El Paso, Texas, and explains the necessity for the Company's proposed weather normalization adjustment to Test Year (January 1, 2020, through December 31, 2020) sales to levels that are reasonably anticipated to occur from year to year. The total weather adjustment for Texas retail customers is a decrease of 104,734,699 kilowatt hours ("kWh") (-1.63%) from total Texas retail Test Year sales of 6,438,523,591 kWh.

Finally, the testimony examines the energy and demand models that are used to generate long term sales and demand forecasts. The energy and demand forecast methodology is described, along with the historical data used to estimate the model. The 2021 long term energy and demand forecast is shown in Exhibit GN-6 and is shown in support of my testimony and the related schedules that I sponsor in this rate filing package.

TABLE OF CONTENTS

SUBJECT **PAGE**

EXHIBITS

I. Introduction and Qualifications

Q. PLEASE STATE YOUR NAME, AND BUSINESS ADDRESS.

A. My name is George Novela. My business address is 100 North Stanton Street, El Paso, Texas 79901-1341.

Q. BY WHOM ARE YOU EMPLOYED?

A. I am employed by El Paso Electric Company ("EPE" or "Company").

Q. WHAT IS YOUR CURRENT POSITION WITH EPE?

A. I am the Director of Economic and Rate Research.

Q. WHAT ARE YOUR DUTIES AND RESPONSIBILITIES AS DIRECTOR OF ECONOMIC AND RATE RESEARCH?

A. I am responsible for the economic forecasting, load research, and rates functions. I manage and direct the activities of the Economic Research and Rates Department, including the preparation of long-term customer, energy, preparation of weather normalization, and load forecasts; analysis of load research data, and the preparation of load research studies and reports.

Q. PLEASE BRIEFLY DESCRIBE YOUR EDUCATIONAL BACKGROUND.

A. I graduated from The University of Texas at El Paso with a Bachelor of Business Administration in Economics in 2006, a Master of Science in Economics in 2008, and a Master of Business Administration in Finance in 2012. I received a Graduate Certificate in Public Utility Regulation & Economics from New Mexico State University in 2014.

In addition, I have taught undergraduate courses in Macroeconomics and Microeconomics at El Paso Community College.

Q. PLEASE SUMMARIZE YOUR PROFESSIONAL EXPERIENCE.

A. Prior to working at EPE, I worked as the Research Coordinator for the City of El Paso's Department of Economic Development from 2007 to 2008. My duties included calculating incentive packages for new and expanding businesses, producing impact studies, and coordinating recruitment efforts with various public and private stakeholders.

In 2008, I began working for EPE as a Load Research Specialist, where I specialized in analyzing EPE's large customers. I was promoted to Senior Economist in 2011, where my responsibilities included the development of the long-term energy, demand, and customer forecasts utilized for planning purposes. In 2014, I worked briefly for EPE's Energy Efficiency Department as a Program Coordinator where I oversaw energy efficiency initiatives for residential customers in both Texas and New Mexico. In 2014, I was promoted to the Manager of Economic Research, where I oversaw the Company's long-term forecasting and load research programs. I was promoted to Director of Economic and Rate Research in 2021, where I manage and direct the activities of the Economic Research and Rates Departments.

Q. PRIOR TO THIS MATTER, HAVE YOU EVER PROVIDED TESTIMONY IN A REGULATORY PROCEEDING?

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

II. Purpose and Summary of Testimony

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. The purpose of my testimony is to describe the load research function and its role in gathering the energy and demand data necessary for assigning costs to rate classes and the development of tariffs, as well as to describe and support EPE's proposed weather normalization adjustments. In addition, my testimony provides EPE's forecasted sales and demand data and the related schedules that I sponsor in this rate filing package.

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. First, I provide a description of the load research function and its role in gathering the energy and demand data necessary for assigning costs to jurisdictions and to rate classes for the development of tariffs. I provide information about the types of studies conducted by the load research program and the different rate classes for which these studies are performed.

Second, my testimony describes and supports EPE's proposed weather normalization adjustments. My testimony provides a description of the methodology I used to calculate the impact of Test Year (January 1, 2020, through December 31, 2020) temperatures on EPE's sales and revenues. My testimony also explains how the econometric models of energy consumption by rate class were developed, and how the results of those models were used to quantify the monthly weather normalization adjustments for each class of service.

Third, I describe EPE's forecasting methodology and the assumptions that support the demand and energy forecasts presented in my testimony and the related schedules that I sponsor in this rate filing package. I also sponsor the Company's current demand and energy forecast with monthly energy requirements for EPE's proposed Rate Year, January 1, 2022, to December 31, 2022. EPE's most recent long-term load forecast is dated April 11, 2021.

Q. ARE YOU SPONSORING ANY EXHIBITS IN YOUR TESTIMONY?

A. Yes, I sponsor the six exhibits that are identified in the list of exhibits found in the table of contents of this testimony.

Q. WHAT SCHEDULES DO YOU SPONSOR?

A. The schedules I am sponsoring or co-sponsoring are listed with descriptions in Exhibit GN-1.

Q. WERE THE SCHEDULES AND EXHIBITS YOU ARE SPONSORING OR CO-SPONSORING PREPARED BY YOU OR UNDER YOUR DIRECT SUPERVISION?

A. Yes, they were.

III. Load Studies

A. Overview

Q. PLEASE DESCRIBE THE LOAD RESEARCH PROGRAM AT EPE.

A. I manage and oversee EPE's Economic Research Department, which conducts census and sample studies of Texas and New Mexico customer energy and demand usage by rate class to estimate class coincident peak demand, maximum class demand, and non-coincident maximum demand. EPE witness Adrian Hernandez uses this data to allocate costs to jurisdictions and rate classes, and EPE witness Manuel Carrasco uses this data to develop rates based on energy and demand usage.

Q. WHAT IS A CENSUS STUDY?

A. A census study, or 100%-metered study, indicates that every customer in that rate class is being measured with an Interval Data Recorder ("IDR") meter. These studies are typically performed on single customer rate classes or rate classes with a low number of customers. For example, EPE's Texas Large Power Service rate class has about 36 customers, all of which have IDR meters for billing purposes. Rate classes that are based on a census study contain study data in total form, as shown in Schedule Q-5.1. There is no sampling error in developing the total class load. The data presented in Schedule Q-5.1 is based on calendar month information, so, due to differences between calendar months and billing months, the data will not exactly match billing data.

Q. FOR WHICH EXISTING RATE CLASSES IN TEXAS DOES EPE UTILIZE A CENSUS STUDY?

A. Texas rate classes that are evaluated using a census study are as follows:

- Rate 15 – Electrolytic Refining Service,
- Rate 25 – Large Power Service,
- Rate 26 – Petroleum Refinery Service,
- Rate 30 – Electric Furnace Service,
- Rate 31 – Military Reservation Service,
- Rate 34 – Cotton Gin Service, and
- Rate 38 – Large Power Interruptible Service.

Q. WHAT IS A SAMPLE STUDY?

A. Sample studies are performed on rate classes that have a large number of customers. Sample studies are based on sampling selected members of each relevant rate class. For classes with numerous customers, it is not economically feasible to install IDR meters for every customer. For example, the Texas Residential Service rate class is examined as a sample study due to the large number of customers in the class. With approximately 300,000 Texas Residential customers at December 31, 2020, it would not be economically feasible to install IDR meters on all customers in this class. The sample study data is shown in Schedule Q-5.2.

Q. FOR WHICH EXISTING RATE CLASSES IN TEXAS DOES EPE UTILIZE A CURRENT SAMPLE STUDY?

A. The following rate classes in Texas are sampled:

- Rate 01 – Residential Service,
- Rate 02 – Small General Service,
- Rate 11 – Municipal Pumping,
- Rate 22 – Irrigation,
- Rate 24 – General Service, and
- Rate 41 – City and County Service.

Q. FOR RATE CLASSES THAT ARE SAMPLED, WHAT ARE THE PROCEDURES EPE USES TO DEVELOP A SAMPLE DESIGN?

A. EPE uses a stratified random sample process to develop the sample design. The stratified random sample process is composed of the Dalenius-Hodges stratification procedure and the Neyman allocation methodology. The Dalenius-Hodges procedure categorizes each customer into predetermined energy or demand blocks and calculates stratum boundaries based on the frequency of customers per block. It is important that each customer selected for the sample is in the appropriate strata to ensure an accurate weighted average. The Neyman allocation method is then used to calculate the optimal sample size and to allocate samples between the strata. These methods make use of available data to build efficient and cost-effective sample designs.

Q. WHAT DOES EPE DO TO COMPLETE THE DEVELOPMENT OF A SAMPLE STUDY AFTER IT IS DESIGNED?

A. After the steps described previously are completed, EPE selects customers from a random list of candidates and installs survey equipment at each customer's premise, which includes an IDR meter. EPE's Meter Testing Department maintains the IDR meters and performs a monthly translation of the data. The Meter Testing Department screens data to ensure the accuracy and validity of the IDR meter readings. The Economic Research Department performs primary data analysis on the meter data. Data within normal tolerance ranges are merged into the Load Research database.

For the analysis, a "typical customer" for each study is used for data comparison. The data for each account are collected on a continuous basis with meters read monthly. Accounts in each stratum are then averaged, producing a stratum average. Each stratum average is then multiplied by a strata weighting factor to develop the class weighted average. The strata weighting factor is the percentage of customers of the total population being sampled contained in each stratum. This weighted average represents a typical customer for each sample study. The sample studies are stratified as shown in the Schedule Q-5.2.

Q. WHAT PROCESS DOES EPE USE TO KEEP THE LOAD STUDIES CURRENT?

A. EPE reviews each sample study for accuracy and performs restratification if necessary. This review process is done in general for new studies and periodically for restratification every few years. Restratification uses the Dalenius-Hodges and Neyman Allocation techniques to derive a new sample study for a rate class. A new random sample is then selected and new IDR meters are put in place.

For census studies, the customer composition of each rate class is updated every month to ensure full representation.

B. Jurisdictional and Rate Class Allocation Factors

Q. HOW ARE ENERGY AND DEMAND BY JURISDICTION DETERMINED?

A. New Mexico load data are gathered from substations in New Mexico and along the Texas-New Mexico state line. The New Mexico load contribution for each substation is updated on an annual basis. The total New Mexico and wholesale customer's, Rio Grande Electric Cooperative ("RGEC"), coincident demand is subtracted from total system demand to determine Texas coincident load. Maximum and coincident demand by rate class is determined by using billed energy and the estimated load and coincidence factors from the load studies. Energy and demand losses are applied in this model using the most current loss study.

Q. DO THE ENERGY AND DEMAND ALLOCATORS NEED TO TAKE LOSSES INTO ACCOUNT?

A. Yes. Customers are served at different voltage levels and, therefore, have different losses associated with service. For proper allocation of costs, both energy and demand allocators take losses into account to appropriately reflect generation "at the source."

Q. WHAT ADJUSTMENTS WERE MADE TO THE JURISDICTIONAL ENERGY AND DEMAND ALLOCATORS?

A. Generation from EPE's solar resources that were built to serve a specific jurisdiction's customers was directly assigned to the relevant jurisdiction and removed from the retail customers energy and demand usage used in the jurisdictional allocators, as discussed above.

Generation from EPE's solar resources that were built to serve a specific customer were also directly assigned to the relevant jurisdiction and removed from the customers' energy and demand usage.

Q. WHY IS THE ADJUSTMENT FOR DEDICATED RESOURCES TO THE JURISDICTIONAL ENERGY AND DEMAND ALLOCATORS IN THE TOTAL COMPANY COST OF SERVICE STUDY APPROPRIATE?

A. The adjustment is appropriate because the costs associated with these solar resources are recovered from customers in specific jurisdictions and are directly assigned to the relevant jurisdiction in the jurisdictional cost of service study.

Q. HAS EPE MADE ANY NOTEWORTHY CHANGES IN ITS ALLOCATION METHODOLOGY FROM ITS LAST TEXAS BASE RATE CASE FILING IN DOCKET NO. 46831?

A. Yes. EPE has made one noteworthy change to its allocation methodology that differs from Docket No. 46831.[1] EPE changed the load factor used in its calculation of the 4 Coincident Peak-Average and Excess ("4CP-A&E") allocators. Prior to 2015, EPE employed the use of an annual load factor based on the average of the peak demand for the four critical months (June-September) in its calculation of the 4CP-A&E for regulatory filings in its Texas Jurisdiction. In Docket No. 46831, EPE employed a load factor in its calculation of the 4CP-A&E based on the single highest peak demand measured during that test year ("1CP"). EPE has determined that it is proper to return to its past practice of using a load factor based on the four peak months (June-September) in its calculation of the 4CP-A&E versus the single highest peak. Please note that EPE has historically used and continues to use an annual load factor based on the four peak months ("4CP") in its calculation of the 4CP-A&E for regulatory filings in its New Mexico Jurisdiction.

Q. CAN YOU PLEASE DESCRIBE THE RECENT HISTORY FOR EPE'S TREATMENT OF THE LOAD FACTOR USED IN ALLOCATION CALCULATIONS?

A. Yes. In 2015 EPE filed Docket No. 44941,[2] a base rate case in which EPE used an annual load factor based on the 4CP instead of a 1CP in its calculation of the 4CP-A&E. This treatment is how EPE has historically used the load factor in allocation formulas across both of its jurisdictions. During the 2015 proceeding, EPE learned of a recent ruling in Texas on the same matter. The Commission's Order on Rehearing in a recent Southwestern Public Service Company ("SPS") base rate case, Docket No. 43695,[3] found that the use of a 1CP factor was more consistent with how SPS planned and built its generation and transmission systems and should be used instead of a 4CP load factor.

EPE changed its methodology during the 2015 case, Docket No. 44941, to match that of the Commission's ruling in the SPS Docket No. 43695. EPE continued that practice in its most recent base rate proceeding in its 2017 Texas base rate case, Docket No. 46831, however that issue was not litigated in that case, and the case was settled without specifying the use of 1CP for determining load factor.

[1] *Application of El Paso Electric Company to Change Rates,* Docket No. 46831, Order (Dec. 18, 2017).
[2] *Application of El Paso Electric Company to Change Rates,* Docket No. 44941, Order (Aug. 25, 2016).
[3] *Application of Southwestern Public Service Company for Authority to Change Rates,* Docket No. 43695, Order on Rehearing (Feb. 23, 2016).

EPE believes that going back to using an annual load factor based on the 4CP instead of a 1CP in its calculation of the 4CP-A&E is proper and consistent with the purpose of the allocation factor.

Q. WHY HAS EPE MADE THE CHANGE DESCRIBED ABOVE?

A. Using a load factor in the calculation of the 4 CP-A&E allocation factor based on one system peak instead of the average of the 4CP months peaks is not consistent with the purpose of the allocation factor. EPE uses a demand value in its load factor calculation based on the average of the 4CP months instead of a single coincident peak. The system load factor employed to derive the proportions of average demand vs. peak demand should be consistent with the associated allocation. That is, because 4CP is used to allocate the "excess demand," the same four coincident peaks should be employed to calculate system annual load factor. In addition, the underlying premise of using 4CPs rather than a single CP is that 4CPs better capture system peak characteristics than does a single CP. Using 4CP avoids any anomaly during a single peak hour.

Q. IF SYSTEM PLANNING IS SUBSTANTIALLY DRIVEN BY PROVIDING GENERATION TO MEET A SINGLE ANNUAL SYSTEM PEAK WHY SHOULD THE SINGLE PEAK (1CP) LOAD FACTOR NOT BE USED IN 4CP-AE LOAD FACTOR CALCULATION?

A. As mentioned above, EPE changed its load factor methodology in the 4CP-A&E during the 2015 case, Docket No. 44941, to match that of the Commission's ruling in the SPS Docket No. 43695. It was determined in the final order of SPS Docket No. 43695 that the 1CP factor was more consistent than the 4CP with how SPS planned and built its generation and transmission systems and should be used instead of a 4CP load factor. EPE agreed with this line of thought at one time. However, after further review, EPE determined that 4CP is appropriate and reasonable for how its generation and transmissions systems are planned. System Planning uses a forecasted CP, not a historical CP for planning. Unlike a historical CP, a forecasted CP is not a known number but rather a point estimate with a probabilistic dispersion around it reflecting the expected value of the peak. While the forecasted peak appears to be a single number, it actually represents the "expected peak" which is a probabilistic estimate of the maximum load EPE must meet. Using the single CP from the historical test year does not truly reflect a peak for planning purposes. However, averaging four peaks provides a CP that more likely reflects the expected value of peak conditions since it reflects a range of peak values, each of which has some expectation of occurring.

Q. HAS EPE SEEN ANY IMPACT ON THE CLASS ALLOCATORS CALCULATED OVER THE TEST YEAR DUE TO THE COVID-19 PANDEMIC?

A. Yes. The COVID-19 pandemic resulted in a shift in usage patterns over the test year due to business and government office closures and employees working from home as opposed to the office. This phenomena drove significant increased usage from residential customers and a significant reduction in usage from the commercial and city/county customers.

Q. HAS EPE MADE A DIRECT ADJUSTMENT TO ITS ALLOCATOR METHODOLOGY TO ACCOUNT FOR THIS SHIFT IN USAGE PATTERNS?

A. No. EPE is presenting the allocators based on the load requirements observed over the test year. However, a capping adjustment was made to the rates that showed a significant deviation from past usage patterns to account for the abnormalities witnessed in 2020 that are not expected to fully be carried forward. EPE witnesses Manuel Carrasco and James Schichtl discuss the rate capping methodology used in this filing in their direct testimony.

Q. DOES EPE EXPECT THE DEVIATION IN CERTAIN CUSTOMER CLASSES USAGE PATTERNS TO CONTINUE?

A. No. It is yet to be seen exactly how customers classes usage patterns will be affected long-term by the COVID-19 pandemic. However, EPE expects customer usage patterns to start returning to normal as the pandemic improves, meaning a reduction in usage by its residential customers and an increase in its commercial and city/county customers from the significant changes witnessed over 2020. This change is not expected to happen immediately, as not all businesses and offices that closed due to the pandemic will open again or under the same operating parameters. In addition, employees working from home as opposed to the office can have varying reintegration timelines and employers can choose to adopt more flexible approaches to remote work going forward. Because of this, EPE chose not to employ or incorporate a previous year set of allocators that will not capture any COVID-19 pandemic influences on usage characteristics. Instead, the capping mechanism mentioned in my testimony above provides a reasonable methodology for rate treatment that incorporates the pandemics impact on usage while at the same time limiting the most significant deviations that are not expected to continue.

C. Residential Distributed Generation

Q. IS EPE SUPPLYING ANY NEW SAMPLE STUDIES FOR PROPOSED NEW RATE CLASSES IN THIS FILING?

A. No. However, EPE has continued to study and monitor its residential distributed solar generation ("DG") customers and wants to highlight their recent load patterns and usage characteristics. EPE's load studies provide data about the different load characteristics of these residential DG customers compared to non-DG, residential customers.

Q. DOES EPE HAVE DATA TO COMPARE THE USAGE PROFILE FOR RESIDENTIAL DG CUSTOMERS WITH THAT OF RESIDENTIAL CUSTOMERS?

A. Yes. The usage profile for residential DG customers is noticeably different than that of the usage profiles of residential customers. Figure GN-1 below compares the delivered load profile for residential DG customers to their total household load profile. The total household load represents the total consumption of residential DG customers regardless of their solar production.

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Figure GN-1

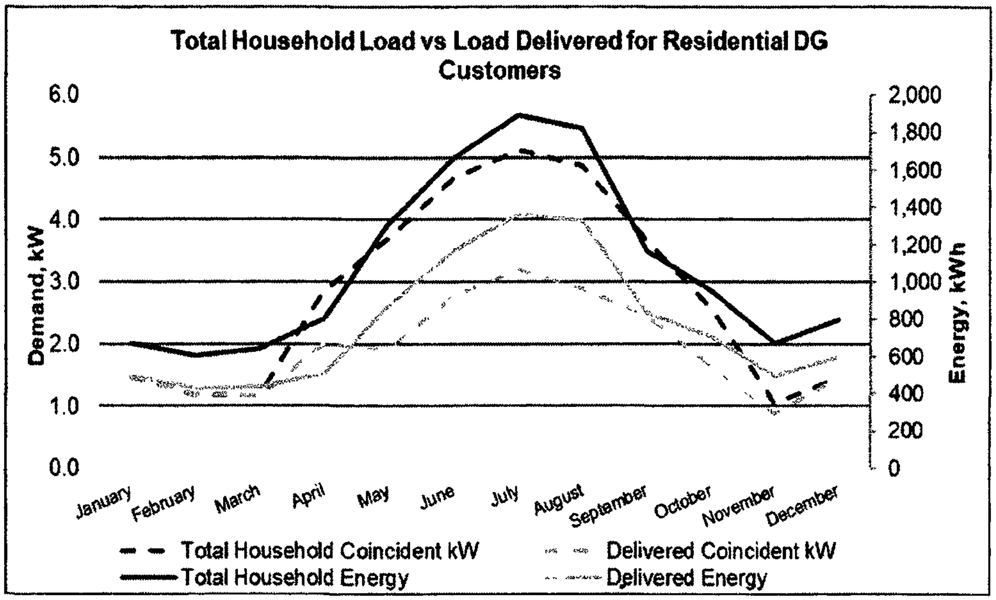

Figure GN-1 uses the interval data from the residential DG bi-directional and REC[4] meters to calculate each customer's total household consumption. It shows a significant decrease in both coincident demand and energy delivered for residences that become residential DG customers. However, we can also compare the delivered load profile of residential DG customers to the load profile of a residential strata. Figure GN-2, below, compares the delivered load profile for residential DG customers to the delivered load profile of residential customers in Strata 4. Strata 4 from the Texas Residential load study was chosen because the total household load of residential DG customers closely follows the consumption patterns of the residential customers that fall into this strata. Figure GN-2 shows similar usage patterns to those in Figure GN-1.

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[4] *Measures the energy produced by customer owned solar systems.*

Figure GN-2

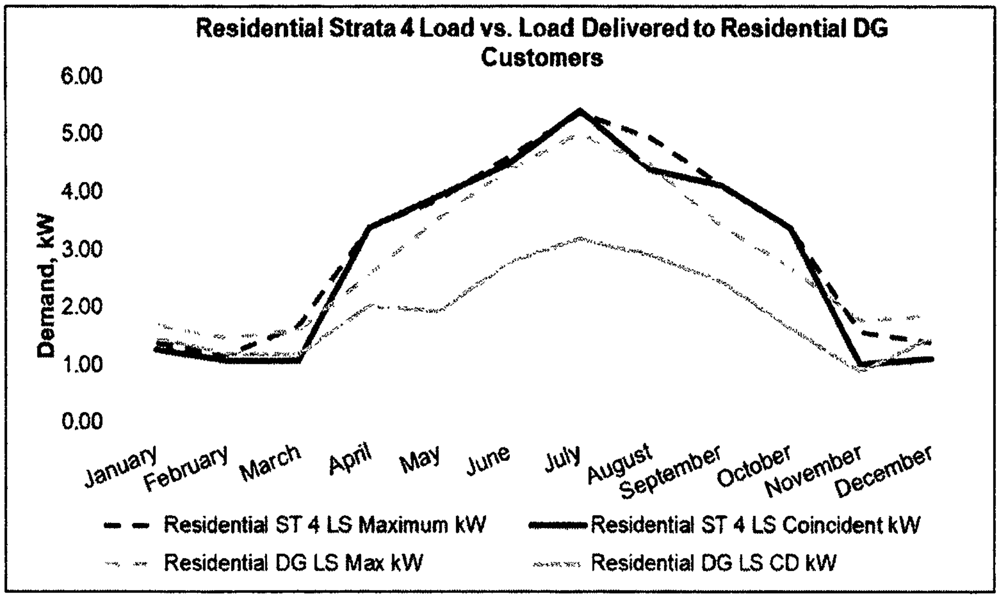

Figure GN-3, below, compares the hourly, mountain standard time ("MST"), delivered load profile for residential DG customers to the hourly delivered load profile of residential customers in Strata 4 during the four summer months of June through September 2020. This figure shows that the summer usage patterns of both customer groups have distinct consumption characteristics. At the time of the 2020 system peak, consumption was lower for residential DG customers compared with the residential customers in Strata 4.

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Figure GN-3

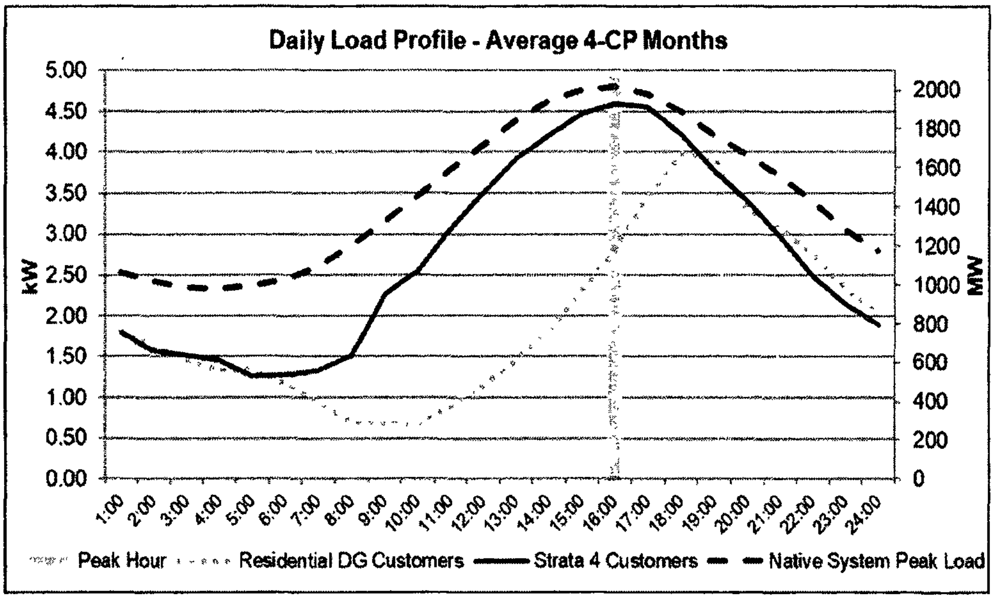

Figure GN-4, below, compares the hourly delivered load profile for residential DG customers to the hourly delivered load profile of residential customers in Strata 4 during the December 2020 peak day for EPE (December 2, 2020). Figure GN-4 shows that the usage patterns of both customer groups have distinct daily consumption characteristics over a winter month. Consumption patterns between the two groups vary over the day, but they do move toward one another during the peak hour.

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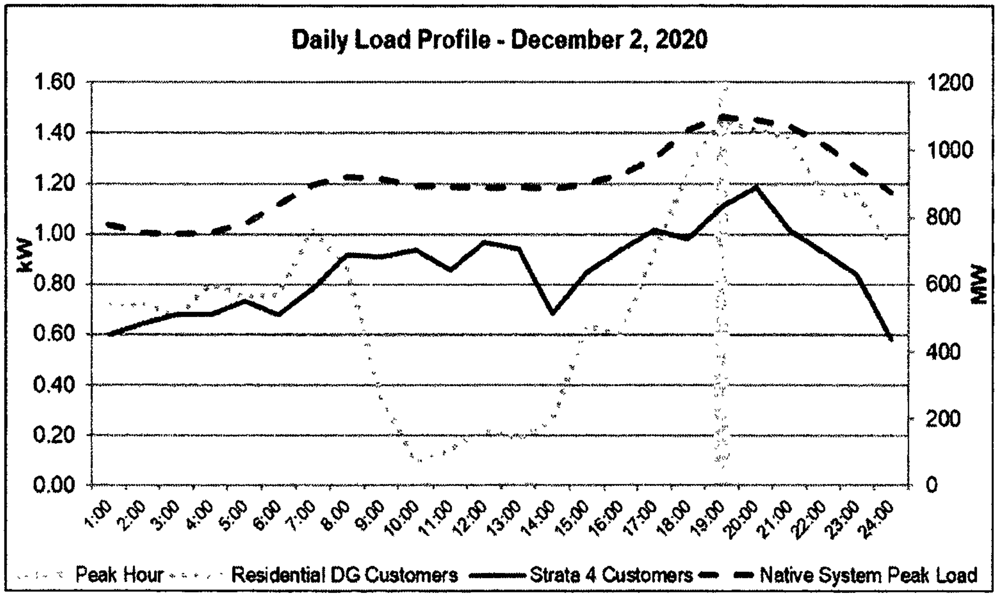
Figure GN-4



The daily peak graphs above, Figures GN-3 and GN-4, highlight that the usage patterns of both customer groups have distinctly different daily consumption characteristics in both the summer and winter months. Consumption patterns between the two groups vary over the day but converge during the evening hours (after approximately 6 pm or 18:00 hours MST). As seen above in Figures GN-3 and GN-4, the evening period is a time where native system peak demand is still high. The daily consumption patterns of residential DG customers are more volatile than residential customers due to their ramp up of energy consumption in the late afternoon to early evening hours. The volatility in the delivered load profile of residential DG customers is highlighted by their monthly load factors, as shown in Figure GN-5 below.

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Figure GN-5

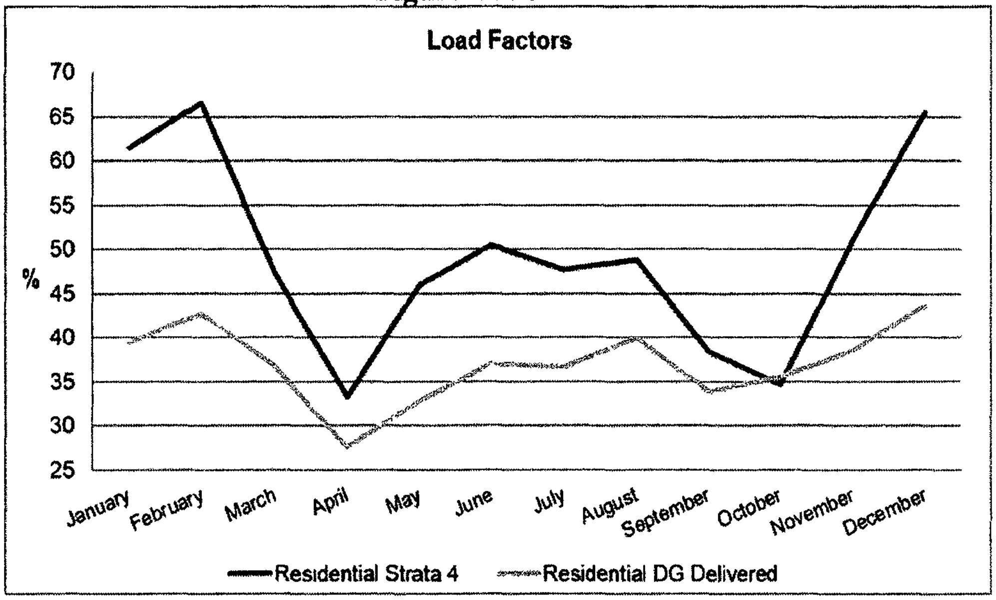

Figure GN-5 has the monthly load factors for both customer groups. As expected, the lower monthly load factor for every month comes from the more volatile group of residential DG customers.

Q. DO RESIDENTIAL DG CUSTOMERS MAINTAIN THEIR REDUCTION IN CONSUMPTION DURING PERIODS OF HIGH SYSTEM PEAK DEMAND?

A. No. Residential DG customers, as seen above in Figures GN-3 and GN-4, ramp up their consumption in the late afternoon to early evening. During this period, EPE continues to serve a high native system peak demand. Figure GN-6 isolates the average DG system's generation profile and compares it to EPE's hourly native system peak profile for the native system peak day on July 13, 2020.

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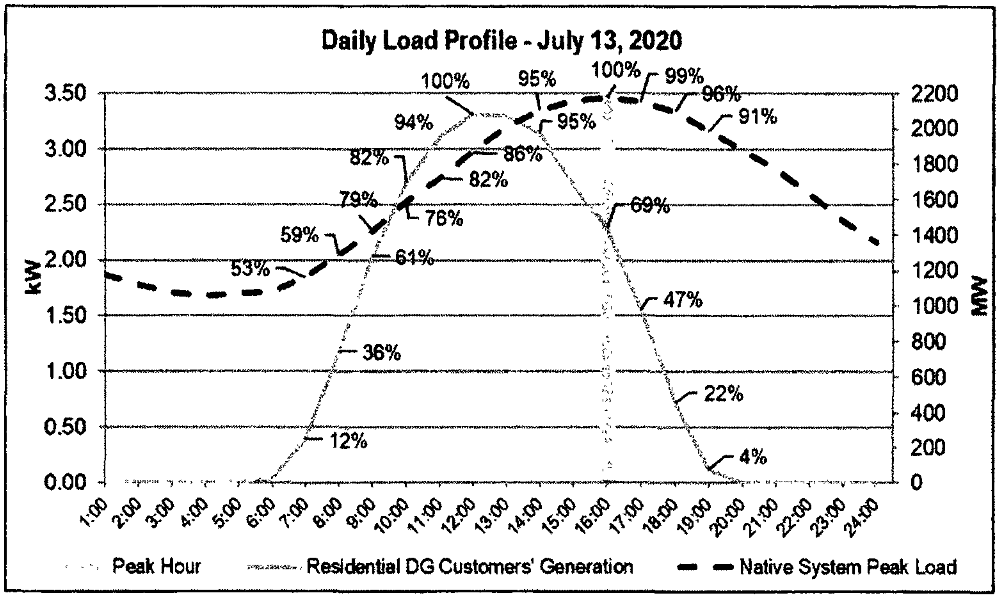
Figure GN-6



As you can see from Figure GN-6, the average DG system production drops significantly after it reaches its maximum output at 12:00 hours MST. However, EPE must serve the drop in the output of the DG systems while the native system peak demand remains at high levels for several hours. In the example above, the average residential DG system produces 69% of its maximum daily output at the time of EPE's system coincident peak (16:00 hours MST). Output continues to decline until the average residential DG system produces 0% of its daily maximum output at 20:00 hours MST. At 20:00 hours, EPE is still serving 91% of the load it had at the time of the coincident peak.

Q. CAN YOU SUMMARIZE AND COMPARE THE DIFFERENCES BETWEEN RESIDENTIAL DG AND RESIDENTIAL CUSTOMERS LOAD CHARACTERISTICS?

A. Yes. Please see Table GN-1 below that summarizes the average load characteristics of residential non-DG and residential DG delivered energy. On average, residential DG customers decrease their energy usage, however, they still have high maximum demand values due to unfavorable DG production weather or increased demand as DG production falls. Table 1 shows that during 2020, the average residential DG customer was delivered

14% more energy than the average residential non-DG customer with a maximum demand that is 58% higher resulting in a much lower load factor.

Table GN-1

Average Load Characteristics of Residential Non-DG and Residential DG Delivered

	Units	December	July	Monthly Avg.
Energy				
Residential Non-DG	kWh	503	1,169	676
Residential DG Delivered	kWh	600	1,368	771
% Difference	%	19%	17%	14%
Demand				
Residential Non-DG	kW	1.09	3.00	1.82
Residential DG Delivered	kW	1.85	5.02	2.87
% Difference	%	70%	67%	58%
Load Factor				
Residential Non-DG	%	62	52	52
Residential DG Delivered	%	44	37	37
% Difference	%	-30%	-30%	-29%

When analyzing the same information as above but on a billed basis (using net energy) the differences between residential non-DG and residential DG is far greater. Please see Table GN-2 below that summarizes the average load characteristics of residential non-DG and residential DG delivered on a billed (net energy) basis. Table GN-2 shows that during 2020 the average residential DG customer, on a net energy basis, was billed for 37% less energy than the average residential non-DG customer but had a maximum demand that is 57% higher. This results in a much lower load factor than the delivered data shown in Table GN-1. Lower load factor customers are costlier to serve because they have a higher demand relative to their energy.

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Table GN-2

Average Load Characteristics of Residential Non-DG and Residential DG Net

	Units	December	July	Monthly Avg.
Energy				
Residential Non-DG	kWh	503	1,169	676
Residential DG Net	kWh	296	1,108	425
% Difference	%	-41%	-5%	-37%
Demand				
Residential Non-DG	kW	1.09	3.00	1.82
Residential DG Net	kW	1.85	5.01	2.86
% Difference	%	70%	67%	57%
Load Factor				
Residential Non-DG	%	62	52	52
Residential DG Net	%	22	30	17
% Difference	%	-65%	-43%	-68%

Q. HAVE YOU PERFORMED ANY ADDITIONAL ANALYSIS ON RESIDENTIAL DG CUSTOMER CLASS?

A. Yes. Exhibit GN-2 provides further analysis on the comparison between residential DG and residential customers load characteristics. Using various measures, Exhibit GN-2 shows that the residential DG customers are markedly different from residential customers. On average, residential DG customers decrease their energy usage, however, they still have high maximum demand values due to unfavorable DG production weather or increased demand as DG production falls. The significantly different usage characteristics of residential DG customers support the need for the current minimum bill as well as the updates to it proposed by EPE. EPE's residential DG rate design proposals are summarized by EPE witness Carrasco.

D. Peak Demand

Q. WHAT IS THE TREND OF THE TOTAL SYSTEM PEAK DEMAND?

A. EPE is a summer peaking utility. This means that EPE's system will experience a significantly higher load during the day between the months of May to September than it experiences at other times of the year. In addition, demand in the off-peak hours during the summer decreases significantly due to the mild weather in El Paso. To efficiently meet peak demand, EPE's generation must be readily available during peak summer conditions and be able to cycle or shut down completely during off-peak periods (e.g., nights, weekends and winter) and turn on without limit as soon as needed. Over the past ten years the system peak demand has had a compound annual growth rate ("CAGR") of 3.0% while native energy has had a CAGR of 0.8%. This has resulted in a decreasing trend in EPE's system load factor.

Over the past decade the EPE system load factor has fallen. Overall, the system load factor dropped from 55.7% in 2011 to 45.4% in 2020. The EPE system load factor has been declining over time in response to two principal factors: a decreasing share of energy consumption by large industrial customers and an increasing saturation rate for refrigerated air conditioners relative to evaporative coolers. In both instances, loads with higher load factors are being replaced by lower load factor loads, resulting in a declining system load factor.

Refrigerated air conditioning units use significantly more electricity than evaporative cooling units. The demand for electricity from refrigerated air conditioning units tends to be highest during hot summer days, when they cycle on and off in response to hot temperatures. In contrast, evaporative air conditioners have limited cycling. This contributes to a downward trend in the system load factor, which means that demand grows faster than energy. Over time, this results in swings in demand that become more pronounced during the summer months, thus requiring additional generation to meet this demand.

In addition to the above, extreme hot weather and the increased growth in customer owned solar DG also can reduce the overall system load factor. As highlighted above in subsection B. of this section, solar DG customers have on average lower load factors than that of non-solar residential customers.

IV. Weather Normalization

Q. DID EPE UTILIZE A WEATHER ADJUSTMENT IN THE ANNUALIZATION PROCESS?

A. Yes. The weather adjustment provides a level of sales that can be expected during a year with average weather. EPE needs to adjust energy sales based on the weather to avoid over- or understating the level of sales that could be expected during a year with average weather. The total weather adjustment for Texas retail customers is a decrease of 104,734,699 kilowatt-hours ("kWh") (-1.6%) from total Texas retail Test Year sales of 6,438,523,591 kWh. Weather can have a profound impact on the month-to-month fluctuations in EPE's system energy sales. This is due in large part to the operation of heating and cooling equipment that is weather sensitive.

In EPE's service area, the adoption of central refrigerated air conditioning is increasing. Central refrigerated air conditioning equipment is replacing evaporative cooling equipment in residences and commercial establishments. Additionally, new residential construction projects include the use of refrigerated air units. As a result, EPE's load has become more weather sensitive, because central refrigerated air conditioning uses much more energy and demand than evaporative cooling equipment.

Q. WHY DOES EPE USE WEATHER STATIONS FOR BOTH EL PASO AND LAS CRUCES?

A. An analysis of historical heating degree days ("HDD") and historical cooling degree days ("CDD") for El Paso and Las Cruces revealed that there are climate differences between the two locations. I note this in Exhibit GN-3. These degree days measure the fluctuations in daily average temperature below or above the designated base temperature (65° Fahrenheit). Temperatures below the designated base temperature lead to increased use of heating appliances and are, therefore, referred to as heating degree days. Conversely, fluctuations in daily average temperature above the 65° base temperature lead to greater use of air conditioning and are referred to as cooling degree days.

Despite the fact that El Paso and Las Cruces are located in a dry desert climate and are less than 50 miles apart, they have some climate differences that make it important to match weather data at both locations to analyze their respective energy sales. Even though the temperatures in both cities tend to move in the same direction relative to each other, El Paso tends to be warmer than Las Cruces. Over the last 10 years, Las Cruces has consistently had fewer annual CDD than El Paso.

Given these consistent differences in weather patterns between the two cities, EPE has concluded that it is appropriate to use two different weather sites for our analysis.

A. Description of EPE's Weather Normalization Adjustment

Q. WHY HAS EPE MADE WEATHER NORMALIZATION ADJUSTMENTS TO THE ENERGY OF THE VARIOUS RATE CLASSES?

A. Adjustments for such fluctuating temperature conditions are made to ensure that the kWh sales levels, upon which rates are based, neither over-recover nor under-recover the utility's allowed cost of service. Kilowatt-hour sales were adjusted to normalize Test Year sales for those rate classes whose use of electricity is sensitive to temperature conditions. During a given period, such as the Test Year, temperature conditions may be warmer or colder than normal. As a result, sales of electricity may be higher or lower than the level that will normally occur.

Q. HOW WERE EPE'S WEATHER NORMALIZATION ADJUSTMENTS MADE?

A. EPE prepared statistical models that measure customer responsiveness to temperatures for all rate classes. Only those econometric models that displayed statistically significant effects to fluctuations in temperature were included in EPE's weather adjustment. EPE found a total of six such econometric models in Texas.

The six individual Rate Class models are:

- Rate 01 – Residential,
- Rate 02 – Small General Service,
- Rate 22 – Irrigation,
- Rate 24 – General Service,
- Rate 31 – Military Reservation Service, and
- Rate 41 – City and County Service.

Q. WHICH RATE CLASSES WERE EXCLUDED FROM WEATHER NORMALIZATION ADJUSTMENTS?

A. Weather normalization adjustments were not made to lighting classes or to Large Commercial and Industrial customer classes, since these customers' uses of electricity are not sensitive to fluctuations in temperature. Further, no weather normalization adjustment is proposed for RGEC since EPE does not have access to end-user information for this wholesale customer.

Q. WHAT IS THE PROCESS FOR CALCULATING WEATHER NORMALIZATION ADJUSTMENTS?

A. Weather normalization adjustments were calculated in a three-step process. First, linear regressions were employed to quantify the influence that factors such as CDD, HDD, income, and other variables have upon monthly electric consumption. A number of linear regression models were examined, and the models were tested for statistical strength and reasonableness.

In the second step of calculating the weather normalization adjustments, the coefficients of the regression equations were translated into monthly kWh adjustments for the rate classes. The regression coefficients for the explanatory variables in each regression equation equal the change in the dependent variable (kWh usage) associated with a one-unit change in the explanatory variable. Thus, the regression coefficients for CDD provide the changes in monthly usage per customer associated with a one CDD change. Similarly, the regression coefficients for HDD provide the changes in monthly usage per customer associated with a one HDD change. Multiplying the degree day regression coefficient by the difference between the normal number of degree days and the Test Year period actual degree days in a month produces the amount by which Test Year period kWh varied from kWh use under normal temperature conditions. Exhibit GN-4 shows these calculations.

In the third step, for the residential class, the above kWh per customer impact is multiplied times the number of monthly customers. Unlike the other rate classes, the residential rate classes are estimated on a use per customer basis because customers display homogenous consumption. The kWh weather impact estimate for these classes is based on a per customer basis so multiplying by the number of customers in that month is necessary to get a total weather effect value. Allocation of the monthly weather normalization adjustments are provided in Exhibit GN-4.

Q. HOW DOES EPE CALCULATE NORMAL WEATHER?

A. EPE uses a 10-year average of monthly National Oceanic and Atmospheric Administration ("NOAA") HDDs and CDDs, adjusted for billing cycles, as a proxy for future average weather conditions. EPE relies on the accuracy and acceptance of NOAA data as being the international standard.

NOAA is a federal agency that monitors climate and collects and publishes local weather pattern data. NOAA calculates HDD and CDD data that are used by forecasters to estimate the impact of weather on energy sales and load. Because CDD and HDD are recorded on a calendar month basis while booked month sales are recorded over 18 billing cycles that normally include portions of two calendar months, it was necessary to transform these calendar month variables into variables that correspond to EPE's billing cycles. This transformation was accomplished through the use of two-month moving average CDD and HDD variables.

Weather fluctuates from year to year. Some years are hotter than others and some are cooler. But over a longer period of time, for example 10 years, any large weather variation that occurs in one year is tempered in the analysis over the time frame.

Q. OTHER THAN CDD AND HDD, WHAT OTHER EXPLANATORY VARIABLES WERE EMPLOYED IN MODELING CONSUMER USE OF ELECTRICITY?

A. In addition to including CDD and HDD variables, each weather model was structured to incorporate economic and demographic variables that are likely to affect the use of electricity by the class being modeled.

Q. WERE THE MODELS TESTED FOR STATISTICAL ACCURACY?

A. Yes. All models met statistical requirements for logical consistency in terms of the explanatory variables employed, signs of the coefficients, and consistency of results using alternative model specifications. In addition, the models were tested for significance of the independent variables as well as goodness of fit. The statistics of the models indicate that we have confidence in the degree day and economic variables employed in the models, and that these variables do an excellent job of explaining changes in energy use.

Q. CAN YOU DESCRIBE HOW THE RESULTS OF THE REGRESSION EQUATIONS WERE TRANSLATED INTO WEATHER NORMALIZATION ADJUSTMENTS FOR EACH AFFECTED CLASS?

A. Yes. As described previously in my testimony, the coefficients of the CDD and HDD variables represent the change in energy use that corresponds to a one-degree day change in temperature. Therefore, the product of multiplying the CDD and HDD coefficients by the differences between actual Base Period degree days and 10-year average degree days provides the amount by which customer use of electricity has been affected by abnormal temperatures. For example, for the Texas Residential model, the July 2020 weather normalization adjustment was calculated as follows:

Normal CDD		629 CDD
Actual CDD	-	684 CDD
Difference CDD		(55) CDD
July CDD Coefficient	X	0.780713 kWh/CDD/Customer
Difference X Coefficient		(43) kWh/Customer
Number of Customers	X	298,614 Customers
Adjustment		(12,822,251) kWh

Note: Due to rounding, the totals in the example above do not add to the total adjustment.

All other months were calculated in the same manner using data specific to that month. The example above employs a monthly use per customer as the dependent variable. The models that employ total rate class kWh as the dependent variable do not have to multiply the resulting change in kWh by the number of customers in the class. Once the monthly kWh use for the weather sensitive classes was developed, the weather adjusted monthly kWh use was further adjusted for year-end customer growth as explained in the direct testimony of EPE witness Carrasco. Please refer to Exhibit GN-4 for the monthly calculations by rate class described previously.

Q. WHAT IS A NOAA NORMAL FOR COOLING DEGREE DAYS AND HEATING DEGREE DAYS?

A. Since the number of degree days can vary significantly on a year-to-year basis, NOAA provides normal HDD and CDD estimates that serve as a proxy for the number of degree days that would be expected to occur during a year with normal weather. To calculate the normal CDD and HDD for a particular month, NOAA uses the 30-year average high and low for each day of the month to calculate a daily CDD or HDD. These daily CDD and HDD are then summed up for the month to arrive at the monthly normal CDD and HDD.

Q. WHY DOES EPE USE 10-YEAR AVERAGE DEGREE DAYS FOR NORMAL WEATHER INSTEAD OF THE NORMAL DEGREE DAYS PUBLISHED BY NOAA?

A. The Commission has found 10 years to be a reasonable basis for the weather adjustment. Using a 10-year average provides a reasonable time frame to encompass cyclical temperature patterns lasting over several years and to smooth out the impact of extreme ranges of temperature that may randomly occur from year to year and that cannot reasonably be expected to be continuously repeated. In addition to being able to encompass cyclical temperature patterns, its smaller size is more reflective of current weather patterns. In addition, the NOAA normal data is only updated every 10 years.

Figure GN-7 provides a graphic display of actual CDD (not adjusted for billing) in El Paso during the Test Year as well as the average number of CDD using a 10-year average. Note that although the Test Year CDD and the 10-year average have a similar shape there is a significant difference in the months of July and August. During the Test Year, May, July, and August are significantly above the 10-year average while September is well below the 10-year average. Please refer to Exhibit GN-5 for the weather data described above.

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Figure GN-7

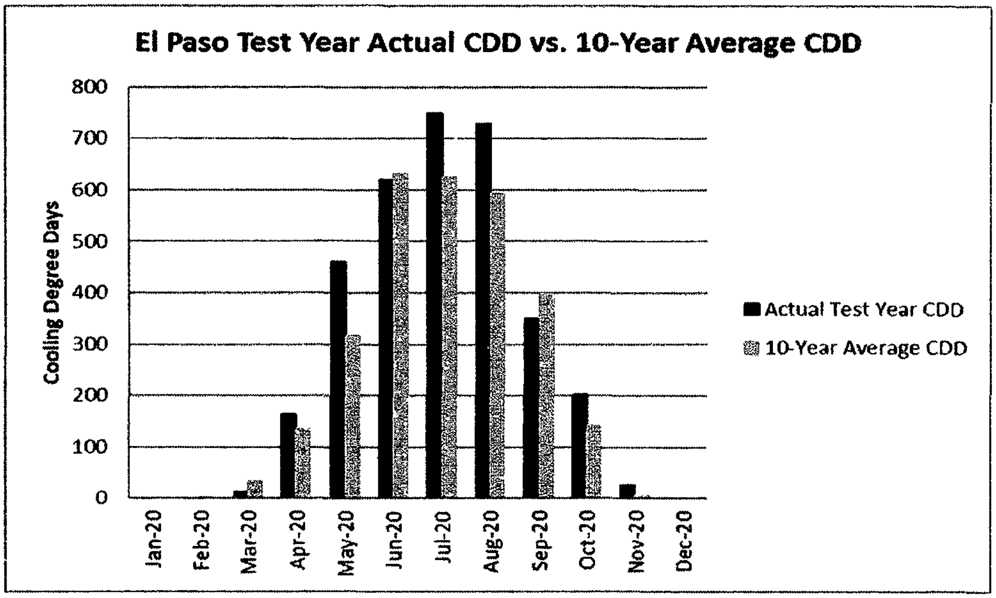
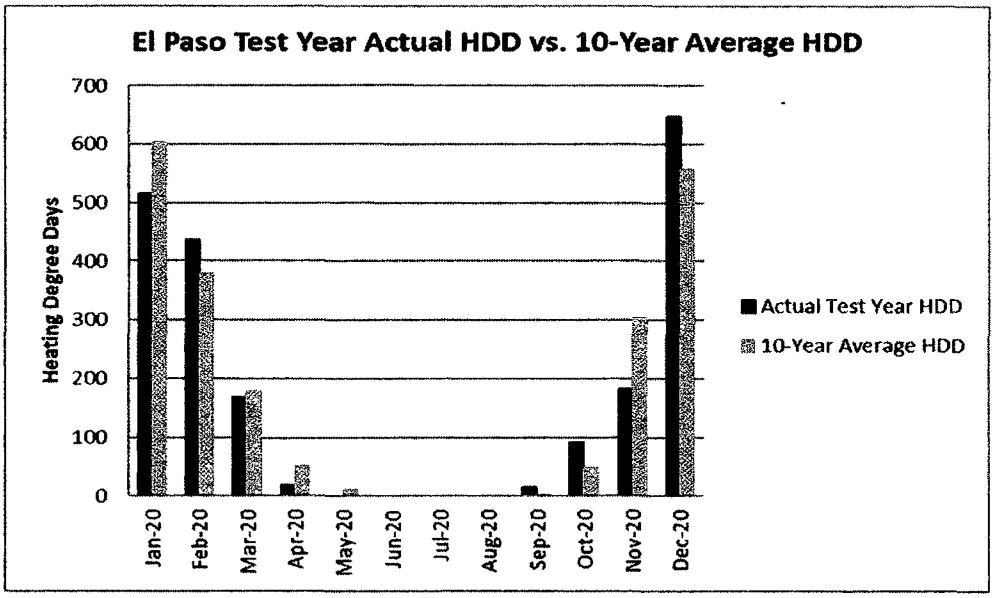


Figure GN-8 provides a graphic display of actual HDD (not adjusted for billing) in El Paso during the Test Year as well as the average number of HDD using a 10-year average. Note that although the Test Year HDD and the 10-year average have a similar shape, January and December is significantly below the 10-year average while September is well above the 10-year average. Please refer to Exhibit GN-5 for the weather data described above.

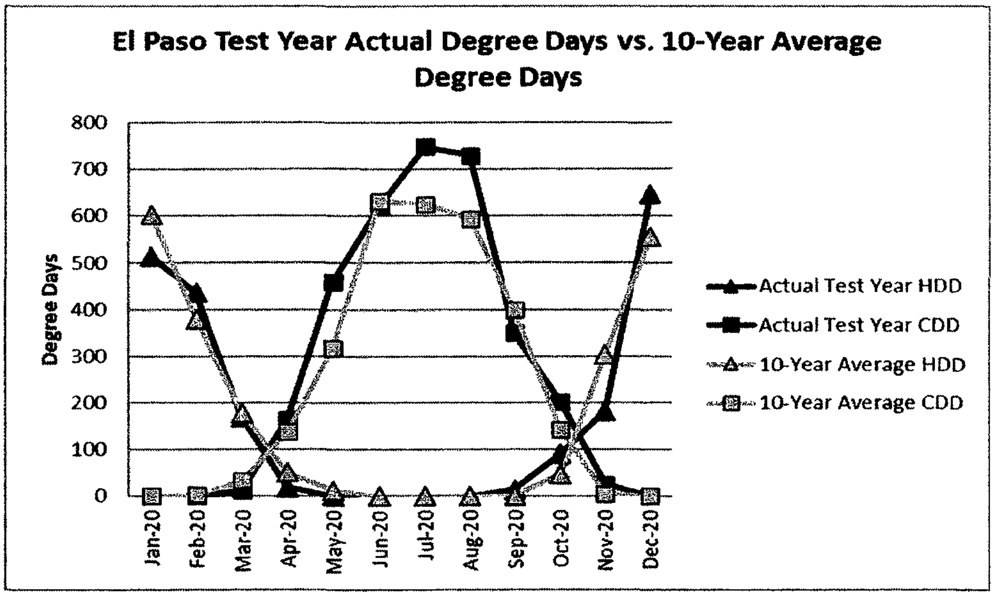
Figure GN-8



Q. HOW DO THE TEST YEAR PERIOD ACTUAL CDD AND HDD FOR EL PASO COMPARE TO NORMAL (10-YEAR AVERAGE) CDD AND HDD FOR THAT RECORDING LOCATION?

A. Actual Test Year (not adjusted for billing) CDD for El Paso are 14.6% higher than the 10-year average CDD and actual Test Year HDD (not adjusted for billing) are 2.8% lower than the 10-year average HDD. Figure GN-9 below compares the Test Year actual CDD and HDD against the 10-year average CDD and HDD.

Figure GN-9



Q. WHAT WAS THE EFFECT OF THE WEATHER NORMALIZATION ADJUSTMENT ON KWH SALES FOR TEXAS RETAIL CUSTOMERS

A. The weather normalization adjustment reflects a reduction in kWh sales to account for the significantly warmer weather during the Test Year. The reduction is necessary to restate sales at more normal levels that can be reasonably anticipated when new rates are placed into effect. The total weather normalization adjustment for Texas retail customers is a decrease of 104,734,699 kWh (-1.63%) from total Texas retail sales of 6,438,523,591 kWh.

This adjustment is provided for each affected rate class by month on Exhibit GN-4 of EPE's rate filing package. In addition, Exhibit GN-4 also provides the calculation of the monthly weather normalization adjustments for each rate class.

V. EPE Energy and Demand Forecast

A. EPE Customers and Service Area Economy

Q. PLEASE PROVIDE A DESCRIPTION OF EPE'S RETAIL SERVICE AREAS.

A. EPE's retail customers are located in far west Texas and southern New Mexico. The Texas retail jurisdiction includes El Paso County and portions of Hudspeth and Culberson counties. The Texas retail jurisdiction accounts for approximately 79% of EPE's retail energy sales. The New Mexico retail jurisdiction includes Doña Ana County and portions of Otero, Luna, and Sierra counties and accounts for the remaining 21% of retail sales. El Paso and Doña Ana counties had estimated 2019 populations of 839,238 and 218,195, respectively.

Q. DOES EPE HAVE ANY FIRM WHOLESALE CUSTOMERS?

A. Yes. EPE provides firm wholesale service to the RGEC at two delivery points that are adjacent to EPE's service area: (1) the Dell City delivery point in Hudspeth County and (2) the Van Horn delivery point in Culberson County. RGEC is a full requirements customer and is, therefore, part of EPE's native system load. RGEC's 2020 peak load was approximately 14 Megawatts ("MW").

Q. PLEASE DESCRIBE THE ECONOMIC COMPOSITION OF EPE'S SERVICE AREA.

A. The majority of EPE's load is distributed within the local Metropolitan Statistical Areas ("MSA") of El Paso, Texas (composed of El Paso and Hudspeth counties), and Las Cruces, New Mexico (composed of Doña Ana County). Over the last year (the 12 months ending December 2020), the El Paso area experienced significant adverse economic impacts as a result of the COVID-19-induced lockdown recession. Regional labor market conditions deteriorated to record levels of unemployment during the second quarter of 2020. However, El Paso continued to benefit from cross-border trade with Mexico during the COVID pandemic. EPE's service territory has a large transportation and warehousing industry due to its location along the United States-Mexico border as well as its proximity to manufacturing operations in a free-trade zone, i.e., maquiladoras in Mexico. El Paso's transportation and warehousing sector continued to thrive during the COVID-19 pandemic and this benefit was reflected in the industrial vacancy rate; which fell to record lows during October of 2020.

The largest industry components and drivers of the El Paso MSA economy have been transportation, warehousing, and government. The transportation and warehousing sector accounts for about 21% of total non-farm employment in El Paso. Other local industries such as manufacturing are also affected by, and in many cases dependent on, the existence and the success of the maquiladoras in Mexico.

The government sector accounts for about 22% of total non-farm employment in El Paso. In addition to federal, state, and local government, total government employment includes the U.S. Army at Fort Bliss, Texas. Fort Bliss has grown from a full-time active duty troop size of 10,000 in 2005 to approximately 39,000 in 2020.

The Las Cruces MSA economy is characterized by a large government sector dominated by White Sands Missile Range ("WSMR") and New Mexico State University. WSMR is geographically the largest military installation in the United States with approximately 3,200 square miles. WSMR and the 600,000-acre McGregor Range Complex at Fort Bliss are contiguous areas for military testing and both are in EPE's service territory. EPE also serves Holloman Air Force Base in Otero County, which is another significant government entity in New Mexico. The government sector directly accounts for approximately 28% of total employment in Las Cruces. Las Cruces also has the commercial establishments necessary to serve the remaining sectors, including a substantial and growing retirement community.

Q. WHAT IS THE OUTLOOK FOR THE SERVICE AREA ECONOMY?

A. Leading economic indicators are strengthening and we predict positive employment growth to occur in the El Paso region during the second half of 2021. Cross-border trade is also expected to be a leading driver of the local economy as all non-essential travel restrictions are expected to be eased during the second quarter of 2021. Northbound traffic flows are expected to increase by approximately 1 million pedestrians and automobiles after the non-essential travel ban is lifted. Total real gross metropolitan product in El Paso was approximately $32.2 billion in 2018 and is estimated to have been $33.2 billion at the end of 2019.

Q. DID YOU UTILIZE INDEPENDENT ANALYSES TO SUPPORT THE OUTLOOK FOR THE SERVICE AREA ECONOMY?

A. Yes. EPE uses a variety of sources to gauge the local economy. It is important to gather various viewpoints from different and established subject matter experts in order to get a clear understanding of the local economy. EPE obtains forecasted regional economic data for El Paso and Las Cruces from IHS Markit ("IHS"). In addition, EPE uses data from the Texas Workforce Commission, Texas A&M Real Estate Center, Texas Comptroller of Public Accounts, and the Federal Reserve Bank of Dallas to support the outlook for the service area economy.

Q. WHAT IS THE PRIMARY SOURCE OF DATA THAT EPE RELIED ON FOR INFORMATION REGARDING THE ECONOMIC OUTLOOK FOR THE COMPANY'S SERVICE AREA?

A. EPE relied primarily on the regional economic forecast for El Paso and Las Cruces produced by IHS. IHS is an internationally recognized data forecasting service. Given that its customer base includes clients in industry, banking, government, and academic institutions, EPE is confident in relying on the data provided by IHS.

In addition to the IHS data, EPE maintains direct contact with its large customers, including Fort Bliss, WSMR, and others. This helps EPE to continuously evaluate the economic outlook for the region.

Q. ARE THERE SIGNIFICANT ECONOMIC FACTORS RELATED TO MEXICO THAT AFFECT THE EL PASO ECONOMY?

A. Yes, there are. The maquiladora industry affects cities along both sides of the U.S.-Mexico border, as recognized by a 2013 study conducted by the Federal Reserve Bank of Dallas ("Bank"). This study, which is available at the Bank's website titled "The Impact of the Maquiladora Industry on U.S. Border Cities," found that a 10% increase in export production in Ciudad Juarez—directly across the international border from El Paso—leads to a nearly 3% increase in overall nonfarm employment in El Paso. The growth of the maquiladora sector in northern Mexico is tied to the level of U.S. production and relative exchange rates. Most recently, maquiladora employment in Ciudad Juarez has been increasing and grew by 9.2%, year-over-year, ending December 2020.

Q. WHAT IS THE PROJECTED OUTLOOK WITH RESPECT TO EPE'S MILITARY CUSTOMERS?

A. The outlook for the military customers in the service territory is difficult to determine. Fort Bliss and WSMR could be affected by budget constraints mandated by the federal government; however, troop count has grown by approximately 10,000 between 2015 and 2020 at Fort Bliss. Any reduction or increase in troops will have a direct effect on energy and demand consumption in EPE's service territory. The Texas Comptroller of Public Accounts estimated that Fort Bliss contributed at least $25 billion to the Texas economy in 2019. A Fact Book published by the U.S. Army Garrison includes a stable outlook for the military base in 2021. It is important to note that Fort Bliss is the Department of Defense's second largest military installation at 1.12 million acres and is second only to White Sands Missile Range, which is also located within EPE's service territory.

B. Forecast Methodology and Assumptions

Q. WHAT APPROACH DOES EPE UTILIZE TO DEVELOP ITS SALES FORECASTS?

A. EPE employs an econometric approach. This approach involves the application of mathematics and statistical methods to the analysis of economic data and the relationship between economic variables to provide an empirical estimation of those relationships. EPE's econometric forecasting models relate customer electric usage to service area trends in population, local economic indicators, and weather to estimate future electricity sales. For example, population, personal income, and weather are typical drivers of electricity sales: more customers and increased income to purchase appliances will typically result in higher electricity demand. The primary reference for these assumptions is the regional macroeconomic forecasts prepared by IHS.

Q. WHAT METHODOLOGY DOES EPE USE TO SUPPORT THE SALES AND DEMAND FORECASTS PRESENTED IN YOUR TESTIMONY?

A. EPE relies on the regional macroeconomic forecasts prepared by IHS to support the econometric models for the energy sales forecasts for the El Paso and Las Cruces areas. EPE develops jurisdictional revenue class sales forecasts based on monthly macroeconomic data and historic and forecasted customer data for each respective jurisdiction. EPE develops individual rate class econometric forecasts if rate classes are experiencing changes not in line with their historical trend. EPE's forecasts for energy sales are functions of variables such as population, income, employment, and other significant inputs. The econometric sales forecasts and resulting peak demand forecast were adjusted to reflect conservation, distributed generation, and load management effects not represented in the historical database.

Q. IS AN ECONOMETRIC FORECASTING METHODOLOGY GENERALLY USED BY COMPANIES IN THE ELECTRIC INDUSTRY?

A. Yes.

Q. ARE ALL OF EPE'S SALES ESTIMATES BASED ON AN ECONOMETRIC MODEL?

A. No. In the few cases where adequate data was not available to support statistical analysis, EPE relied on non-econometric sales and load information. Examples of situations that require non-econometric estimates include significant expansion or reduction by an existing or new customer as well as expansion of distributed generation ("DG") customers and transportation electrification.

Given that DG is relatively new, there is limited historical regional data, so it is not suitable for econometric forecasting models. Future estimates for DG customers and load are based on recent trends, sample studies, and known or reasonably predictable changes in consumption levels.

Finally, similar to DG, EPE is adding in the load requirements for light-duty electric vehicles ("EV") in its 2021 long term forecast. Although EPE has EV forecasts for vehicles in addition to light-duty, such as medium and heavy-duty, EPE is currently only including light-duty vehicles because their load is more present and growth trends are clearer than the other vehicle categories over the forecast period.

Q. HOW DOES EPE DETERMINE THE MONTHLY SYSTEM ENERGY REQUIREMENT (SALES AT THE SOURCE)?

A. EPE combines the annual retail sales, sales to RGEC, and Company use, and then calculates line losses using a loss rate derived from the system loss study conducted by Management Applications Consulting, Inc. ("MAC") in April 2019. These system losses must be included with sales at the meter to accurately develop the total energy requirement needed to deliver electricity to EPE's customers. The annual losses are then allocated to each month based on a historical seasonal pattern. Additional line losses are incurred from off-system wheeling of EPE's power (Losses-to-Others). Finally, a downward adjustment is made to reflect energy efficiency and DG not represented in the historical database.

Q. HOW ARE EPE'S PEAK DEMAND FORECASTS DEVELOPED?

A. EPE uses the native system load factor relationship to estimate future annual peak demands. Load factor defines the relationship between energy and peak demand.

System Load Factor = System Energy / (Peak Demand x Hours)

For example, the annual load factor for 2020 was:

System Load Factor = 8,674,263 MWh / (2,173 MW x 8,784 hours) = 0.454

EPE applied the previous two-year average load factor to "at source" projected energy to calculate the estimated peak demand. These values are then adjusted for projected conservation and load management to calculate native system peak demand.

The demand from wheeling losses is also accounted for to obtain an overall system peak demand. The final adjustment made to forecasted peak demand is to subtract interruptible load. Monthly peak demand is estimated by using the historical relationship between monthly peak demands and the annual peak demand.

Q. WHAT ARE THE MAJOR UNDERLYING ASSUMPTIONS USED IN DEVELOPING EPE'S FORECASTS?

A. The major underlying assumptions for the forecasts are the projections for population, income, weather, and employment.

Q. DOES EPE RELY ON AN INDEPENDENT SOURCE IN ACCOUNTING FOR THOSE MAJOR UNDERLYING ASSUMPTIONS?

A. Yes. The population, income, and employment data series for EPE's service area are taken from the IHS regional economic forecasts for El Paso and Las Cruces that I described earlier in my testimony. IHS's forecasts provide EPE with data that is independent and free from any internal bias. IHS provides EPE with a large data set of regional variables that are routinely updated. Moreover, as previously discussed, IHS is an internationally recognized macroeconomic forecasting service with a customer base that includes clients in industry, banking, government, and academic institutions.

Q. HOW HAS THE COVID-19 PANDEMIC IMPACTED EPE'S SALES FORECAST?

A. The COVID-19 pandemic resulted in a shift in usage patterns due to business closures and employees working from home as opposed to the office resulting in increased usage from residential customers which tend to be low load factor customers. This coupled with the extreme weather in the summer of 2020 attributed to an unprecedented growth in peak demand and changes in volumetric energy between customer classes. EPE witnessed a year-over-year increase to native system peak demand of 9.5% or 188 MW in 2020 and saw large volumetric energy increases to residential customers and significant reductions to many of its commercial and government customers. Although EPE saw movement of sales between customer classes on an annual aggregate basis, energy sales were not significantly impacted. The 2021 Forecast predicts a year-over-year downward adjustment in native system peak demand of 52 MW assuming normal weather and the return of people to their places of work.

Q. PLEASE SUMMARIZE THE FORECASTS USED IN THIS FILING.

A. The forecast summary shows that the 10-year CAGR for native system energy and native system demand is approximately 1.1% and 0.9%, respectively. This is reasonable given recent customer growth trends and expected employment growth in EPE's service area over the long term. The Company's energy and demand forecast summary is provided in Exhibit GN-6.

VI. Summary and Conclusions

Q. PLEASE SUMMARIZE YOUR TESTIMONY AND CONCLUSIONS.

A. My testimony discusses EPE's load research function and its role in gathering the energy and demand data necessary for assigning costs to jurisdictions and rate classes, as well as for the development of tariffs. The load research methodologies used by EPE are fair and reasonable for the assigning of costs and the development of tariffs and consistent with prior filings.

I describe and support the proposed weather normalization adjustment. In my opinion, the proposed weather normalization adjustment is both fair and reasonable. The economic models used to develop the adjustments employ standard industry practices, and the models have a high level of statistical confidence. The proposed weather normalization adjustment follows a consistent methodology with the weather adjustment submitted in the previous case. Furthermore, the weather normalization adjustment fairly and reasonably reflects normal weather during the Test Year Period. The total weather normalization adjustment for Texas retail customers is a decrease of 104,734,699 kWh (-1.63%) from total Texas retail sales of 6,438,523,591 kWh.

Finally, I describe EPE's forecasted sales and demand in support of various schedules. In my opinion, the forecasted sales and demand values are both fair and reasonable. These growth rates are consistent with recent customer growth trends and the economic growth projections for our service territory.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

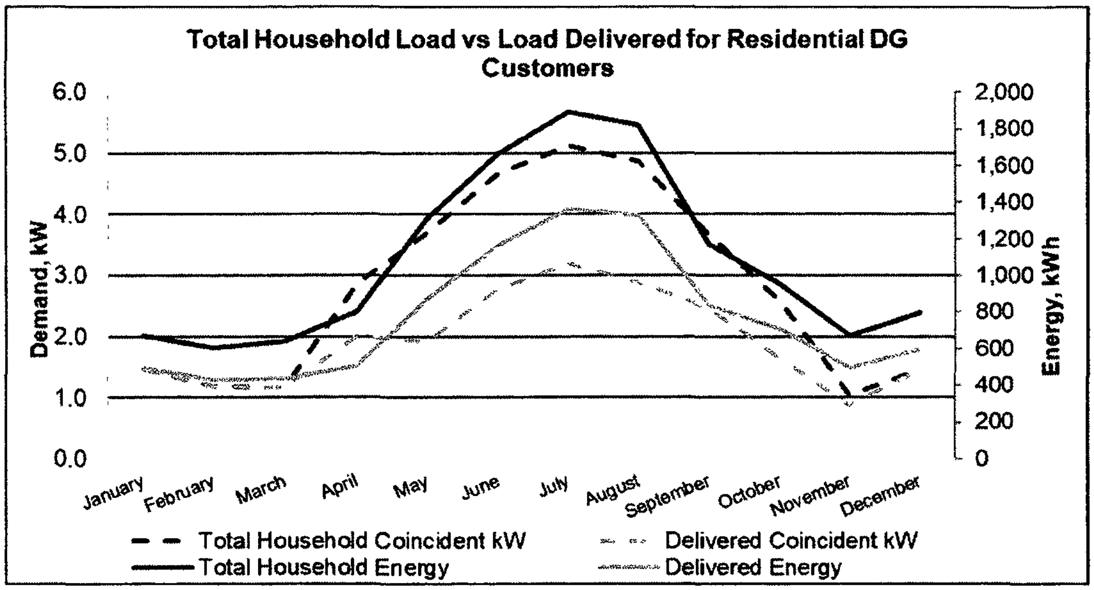
SCHEDULES SPONSORED BY G. NOVELA

Schedule	Description	Sponsorship
H-12.1	SUPPLY AND LOAD DATA	Co-Sponsor
H-12.5a	LINE LOSSES & SYSTEM'S OWN USE	Co-Sponsor
H-12.5f	ON SYSTEM SALES (WHOLESALE & RETAIL)	Sponsor
H-12.6a	MONTHLY MINIMUM AND PEAK DEMAND	Sponsor
H-12.6b	MONTHLY LOAD DURATION CURVE	Sponsor
H-12.6c	ANNUAL LOAD DURATION CURVE	Sponsor
O-1.3	UNADJUSTED TEST YEAR DATA BY RATE CLASS	Sponsor
O-1.4	MONTHLY ADJUSTED TEST YEAR DATA BY RATE CLASS	Sponsor
O-1.6	SYSTEM LOAD FACTOR	Sponsor
O-1.8	OPERATING STATISTICS NARRATIVE	Co-Sponsor
O-1.9	PEAK DEMAND BY RATE CLASS	Sponsor
O-2.1	MODEL INFORMATION	Sponsor
O-2.2	MODEL DATA	Sponsor
O-2.3	RAW MODEL DATA	Sponsor
O-6.1	UNADJUSTED kWh SALES BY MONTH OF THE TEST YEAR	Sponsor
O-6.2	ADJUSTED kWh SALES DATA	Sponsor
O-6.3	SYSTEM LINE LOSS CALCULATION	Sponsor
O-7.1	SALES AND DEMAND DATA	Sponsor
O-7.2	HISTORICAL SALES DATA	Sponsor
O-8.1	HISTORICAL WEATHER DATA	Sponsor
O-8.2	HISTORICAL WEATHER DATA AFTER WEIGHTING AND BILLING CYCLE ADJUSTMENTS	Sponsor
O-8.3	NORMAL HEATING AND COOLING DEGREE DAYS	Sponsor
O-8.4	65 DEGREE F BASE TEMPERATURE RESPONSES	Sponsor
O-9.1	RATE YEAR FORECAST MODEL INFORMATION	Sponsor
O-9.2	MODEL DATA	Sponsor
O-9.3	RAW MODEL DATA	Sponsor
O-10.1	HISTORICAL DATA	Sponsor
O-10.2	PERSONAL INCOME DATA (NOMINAL PERSONAL INCOME)	Sponsor
P-9	DEMAND AND ENERGY LOSS FACTORS	Sponsor
P-12	SUPPORT FOR PRODUCTION ALLOCATION METHODOLOGY	Co-Sponsor
Q-5.1	DEMAND DATA BY CUSTOMER CLASS	Sponsor
Q-5.2	DEMAND, CONSUMPTION, AND CUSTOMER DATA BY STRATA	Sponsor
Q-5.3	DEMAND ESTIMATES METHODOLOGY	Sponsor

Comparing Load Characteristics of Texas Non-DG Residential Customers to Texas Residential Distributed Generation Customers

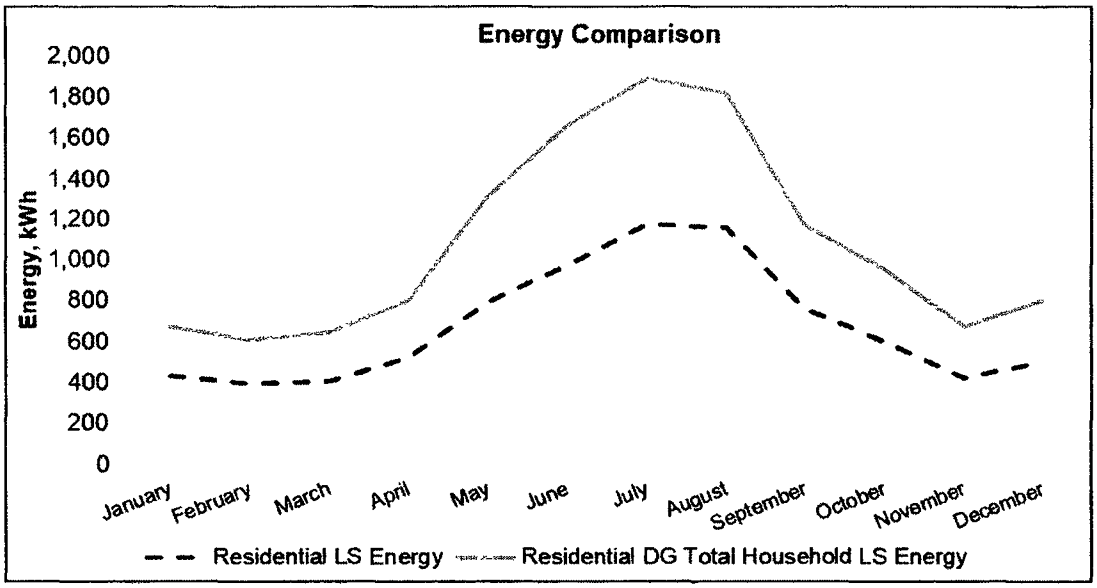
- The Economic Research Department designs sample load studies to determine load characteristics for large rate classes. With approximately 300,456 customers, a load study sample is used to model load patterns for the Texas residential class. Sampled Texas residential customers consumed an average of 676 kWh monthly during the year ending December 31, 2020.
- Load patterns for residential DG customers are modeled in the same manner as the Texas residential class. For the year ending December 2020, the residential DG sample consisted of 57 customers. As estimated by the Texas residential DG load study, residential customers with DG had an average monthly total household load of 1,084 kWh for the test year, supplied through a combination of EPE system resources and self-generation.
- The following defines many of the types of energy analyzed in this comparison. EPE delivers energy to DG customers when their energy consumption is greater than that of their DG system's energy production. Delivered energy reflects the energy delivered by EPE to the residential DG customer. Received energy reflects the energy received by EPE from the residential DG customer. Net energy is the difference between the delivered and received energy. The total household load represents the total consumption of residential DG customers regardless of their solar production. Total household energy is the sum of the net energy (difference between the delivered and received energy) plus the energy production of the customer's DG system.
- The usage profile for residential Texas DG customers is noticeably different than that of the usage profiles of Texas residential non-DG customers. See Figure 1, below, which compares the delivered load profile for residential DG customers to their total household load profile. Figure 1 shows a significant difference in both coincident demand and energy delivered for residences that become residential DG customers.

Figure 1



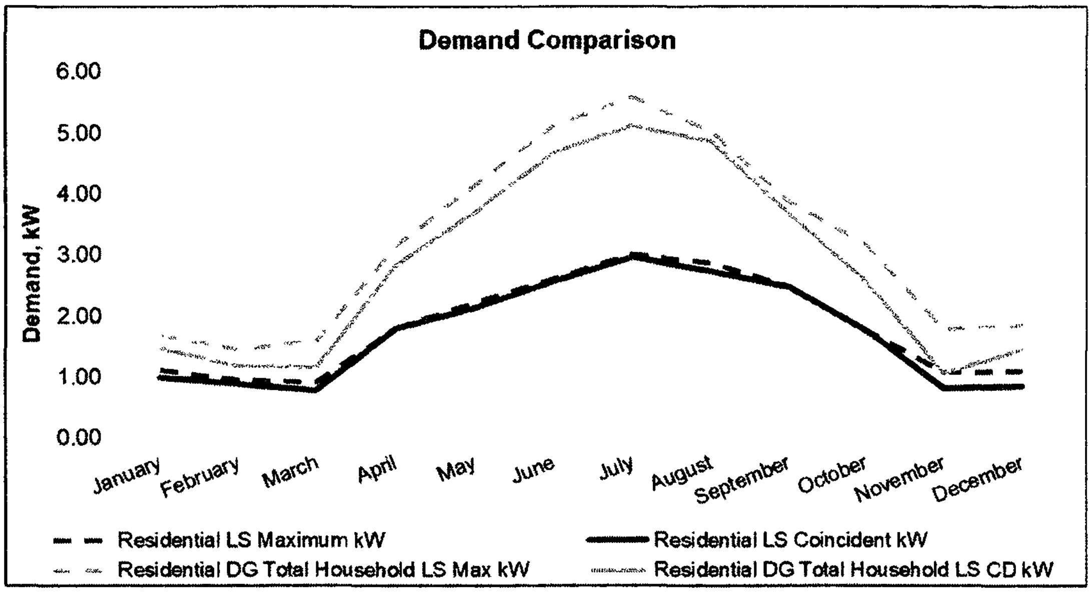
- On average, residential Texas DG customers consume an estimated 60.21% more total household energy per year than the typical non-DG residential customer (see Figure 2).
- As shown in Figure 2, this difference is more pronounced in the four coincident peak (CP) summer months (June - September) where a typical non-DG residential customer consumed an average of 1,015 kWh and a residential DG customer consumed 1,636 kWh monthly, or approximately 61.18% more.

Figure 2



- The same pattern can be seen in Figure 3 below, when comparing total household average coincident and maximum demand for these customers. "Coincident" demand refers to demand measured at the time of the EPE monthly native system peak, where "maximum" refers to the residential DG customers demand when they peaked as group regardless of the time of the native system peak.
- The average residential DG customer's total household load is 75.82% and 63% higher than a typical residential customer for maximum kW and coincident kW, respectively. During the 4CP months, residential DG customer's total household load is significantly higher than the load for the average residential customer, approximately 78.83% for maximum kW, and 71.26% for coincident kW.

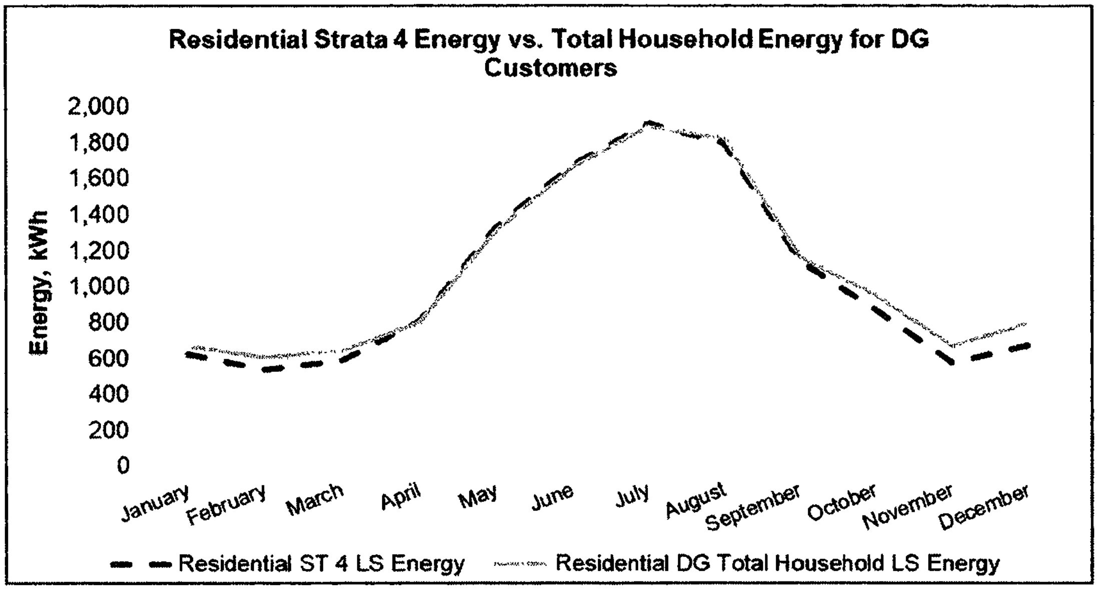
Figure 3



Residential DG Customers are Typically High Usage Customers

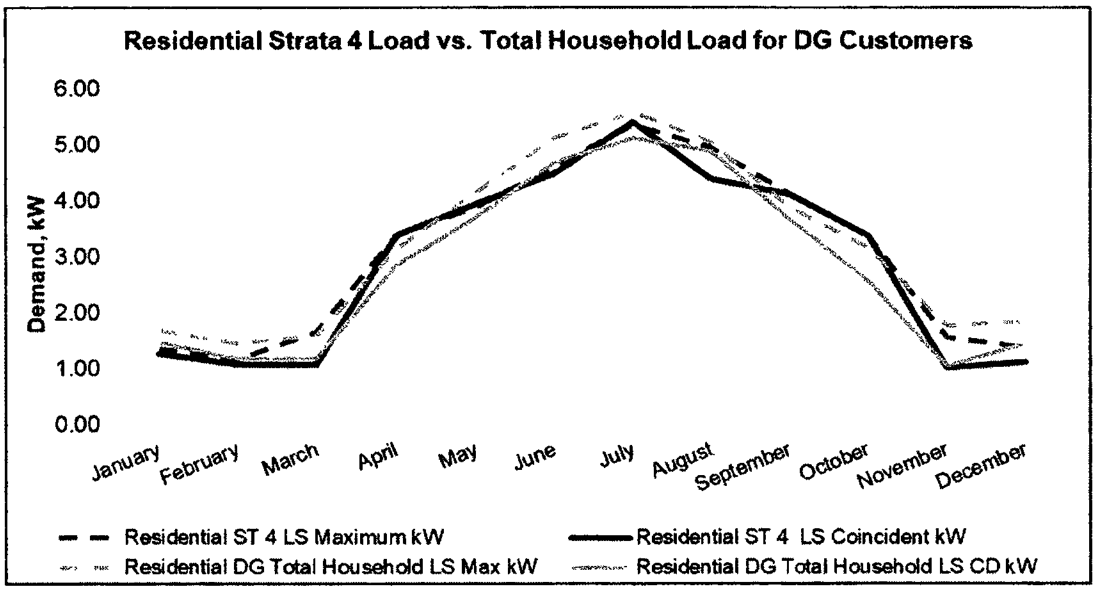
- On average, residential DG customers consume more energy than the typical residential customer. Therefore, it would be more practical to analyze these residential DG customers with other customers that have similar usage patterns.
- The Texas Residential load study is stratified by energy and consists of five strata. The strata boundaries are listed below.
  - Strata 1: 0 – 300 kWh
  - Strata 2: 301 – 600 kWh
  - Strata 3: 601 – 900 kWh
  - Strata 4: 901 – 1,400 kWh
  - Strata 5: 1,401 – 23,400 kWh
- With an average annual consumption of 1,084 kWh per month, residential DG customers are more comparable to the high usage customers that fall in strata 4. Figure 4 below shows the similarity between the residential DG customers and the strata 4 non-DG residential customers.
- The energy consumption between the two types of customers is almost identical.

Figure 4



- The same observation can be made for demand patterns between a residential DG customer's total household load and a high usage non-DG strata 4 customer in Figure 5 below.

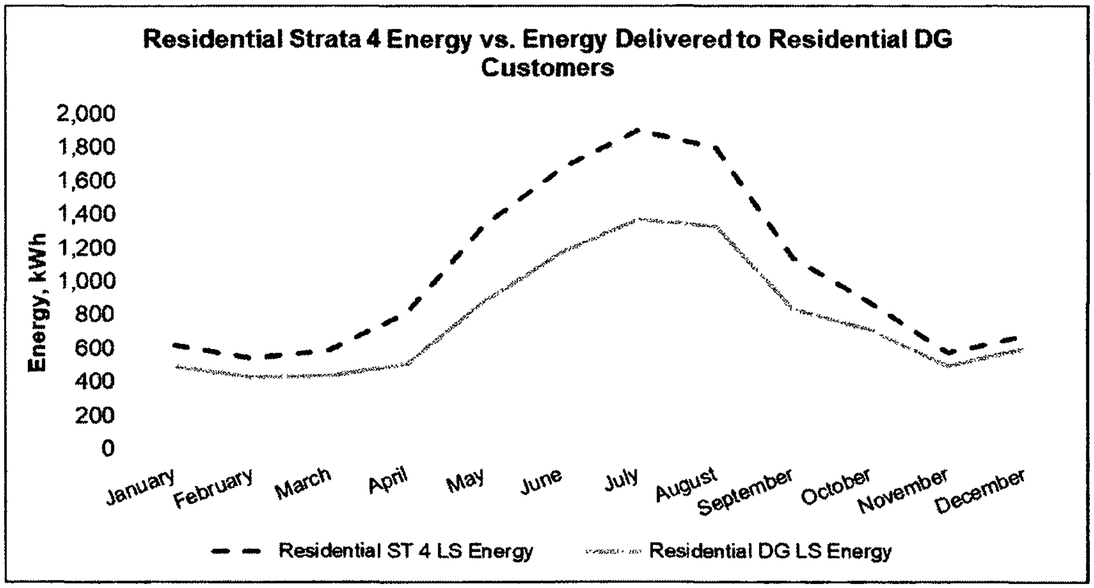
Figure 5



Load Delivered to Residential DG Customers Compared to Residential Strata 4 Customers

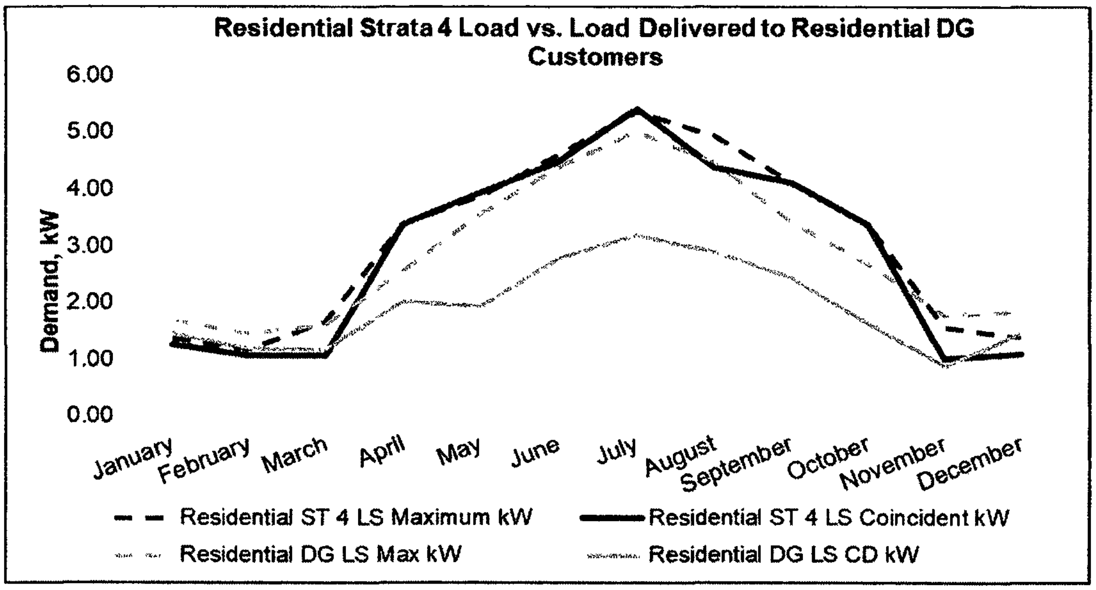
- Despite the similarities of a residential DG customer's total household consumption to the high usage customers that fall in the Texas strata 4 load study, these customers' solar panel production partially offsets the amount of energy provided to them by El Paso Electric, creating a markedly different retail service profile.
- A residential strata 4 customer consumed an average of 1,042 kWh monthly during the test year, while EPE delivered residential DG customers an average of 771 kWh monthly, or 26% less. This difference can be seen in Figure 6 below.

Figure 6



- Figure 7 below, illustrates how a customer's load requirements change when considering only the load delivered to residential DG customers as opposed to their total household consumption. The load for both maximum demand and coincident demand follow the expected patterns.

Figure 7

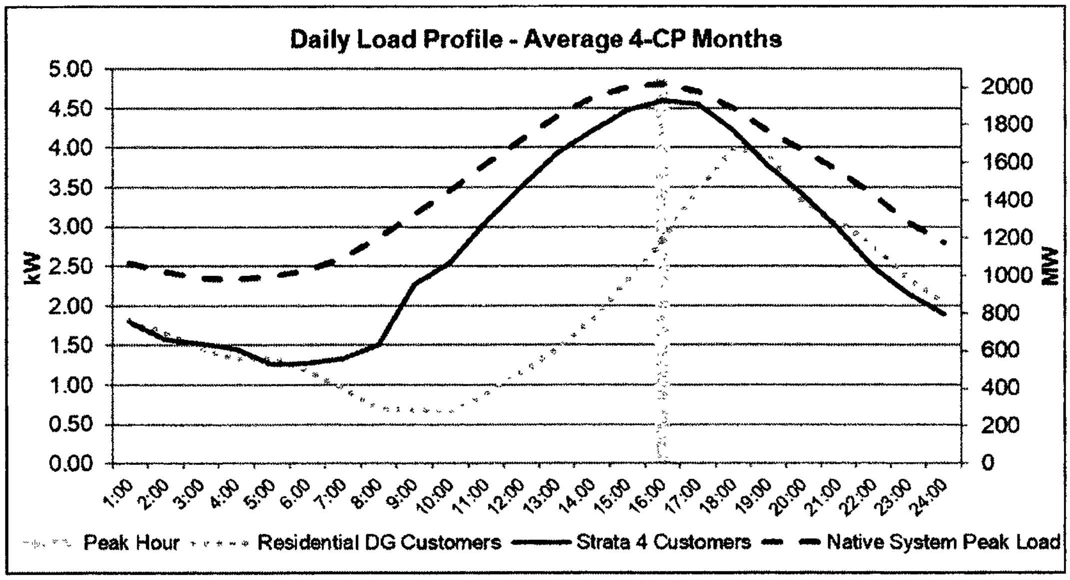


- A typical residential customer's peak demand (Maximum Diversified Demand) occurs in the late afternoon hours. The same is true for residential DG customers whose maximum demand occurs in the late evening when not much sunlight is available to displace their load. As a result, the maximum demand for a residential DG customer is not distinctly different than that of a residential strata 4 customer with no solar panels.
- During the 4CP months, the monthly EPE native system peak occurred at 16:00 MST from June through September. The graph (Figure 7) depicts a decrease in load requirements for the residential DG customers during these months. During this time, the load delivered to the residential DG customers was 38.34% lower than the residential customers in strata 4. Residential DG customers contribute less on average to the EPE system peak demand during the 4CP summer months.
- During the winter months, where the native peak occurred at 19:00 MST, the coincident demand for a residential DG customer does not significantly differ from a regular strata 4 residential customer's coincident demand. During these months, residential DG customers contribute to the EPE system peak in roughly the same proportion as do strata 4 customers.

Hourly Interval Load During Peak Periods

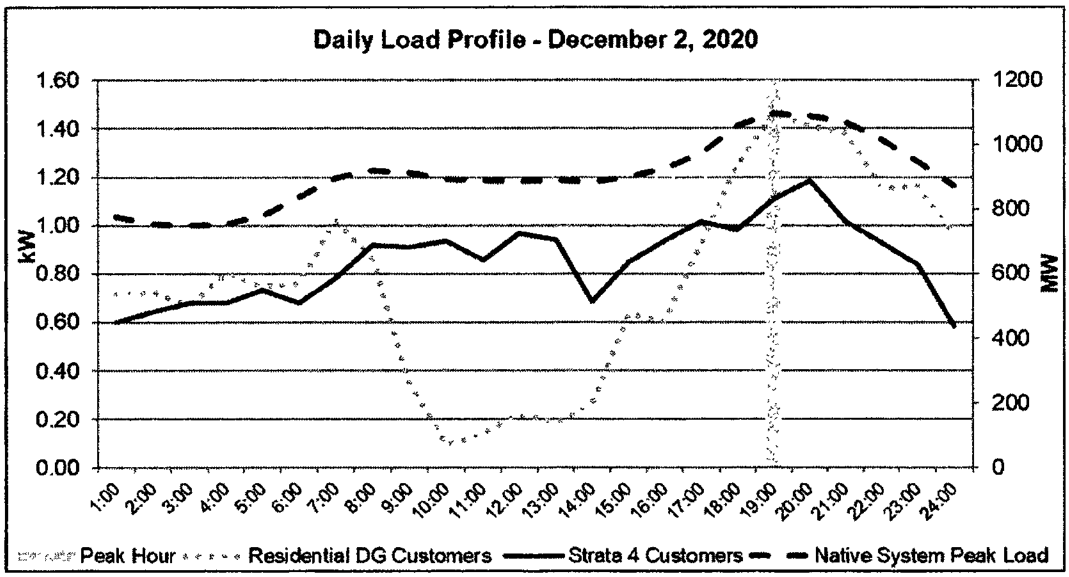
- Figure 8 below, compares the hourly delivered load profile for residential DG customers to the hourly delivered load profile of residential customers in Strata 4 during the 4 CP months of June–September of 2020.

Figure 8



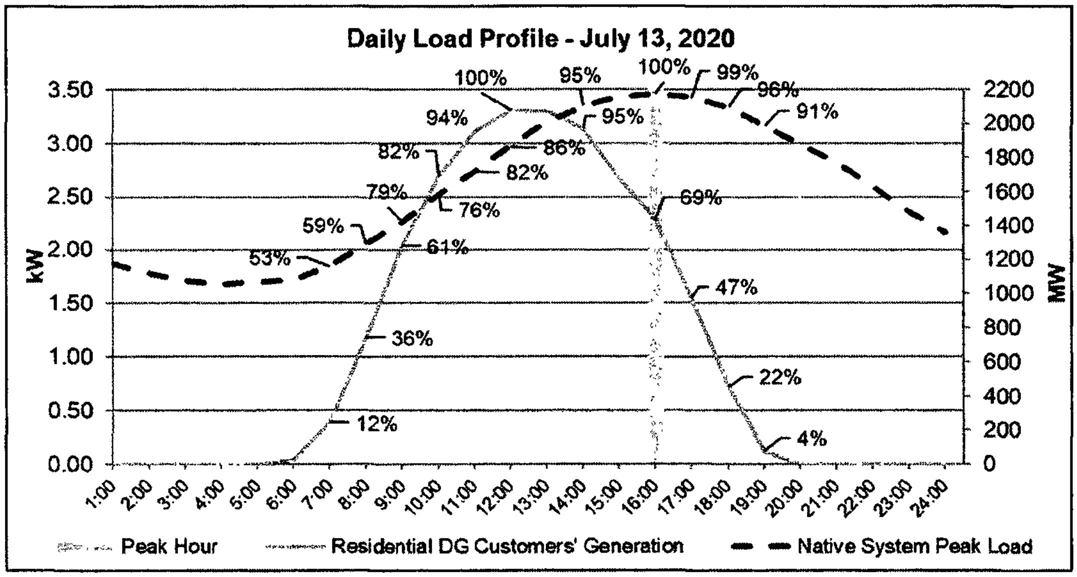
- During daylight hours, the load provided to residential DG customers by EPE is greatly reduced by the customer's solar generation.
- The load patterns during a winter peak day are similar. Figure 9, below, compares the hourly delivered load profile for residential DG customers to the hourly delivered load profile of residential customers in strata 4 during the peak day in December 2020.
- The residential DG customers load is partially offset by the solar panel's production during the daylight hours. However, given that the peak during a winter month occurs during night time, the difference in usage between both customers is reduced.

Figure 9



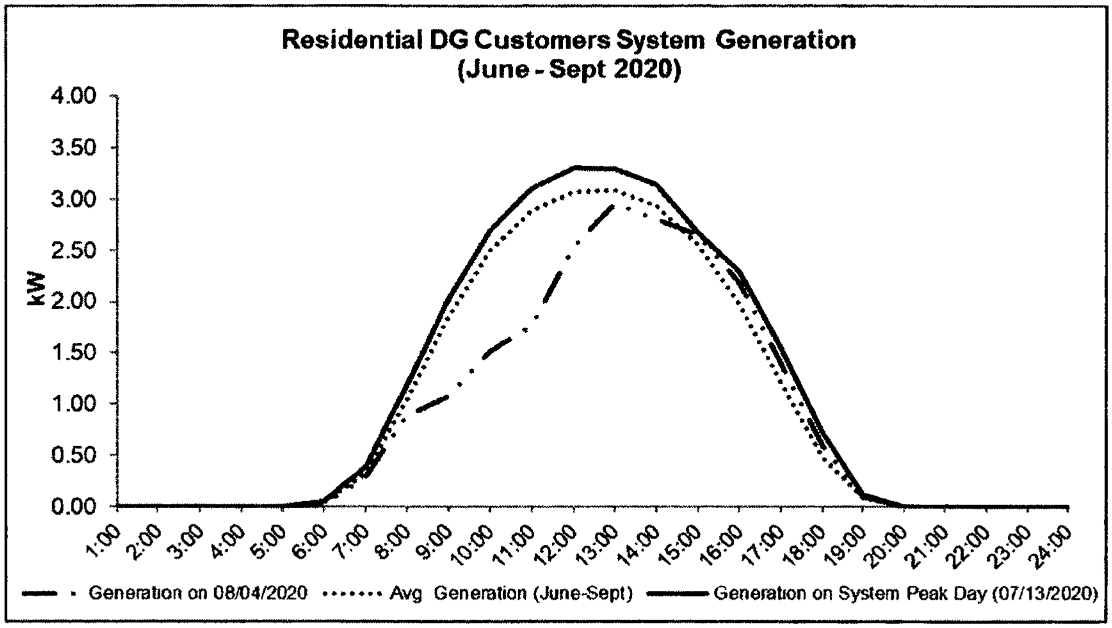
- Figure 10, below, isolates the average DG system's generation profile and compares it to EPE's hourly native system peak profile for the native system peak day on July 13, 2020. The load patterns during a winter peak day are similar.
- As can be seen from Figure 10, the average DG system production drops significantly after it reaches its maximum output at 12:00 hours. However, EPE must serve the drop in the output of the DG systems while the native system peak demand remains at high levels for several hours.

Figure 10



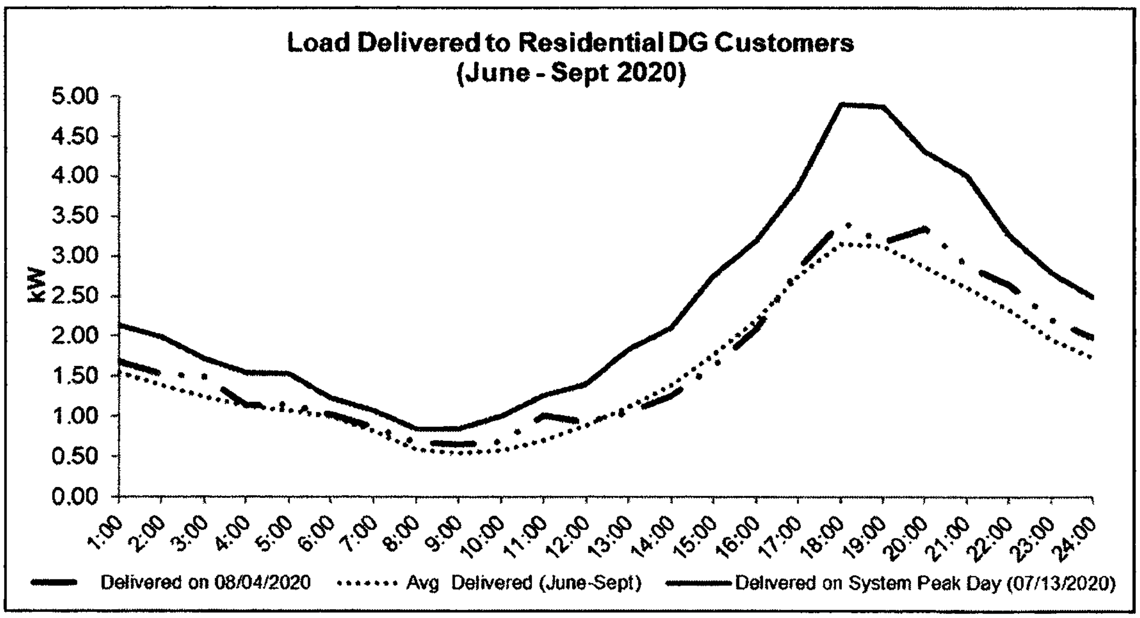
- Figure 11, below, looks at the average DG system's generation profile over a variety of days in 2020. Specifically, on the day of the 2020 native system peak, an average for all days June-September 2020, and a day in summer (8/04/2020).
- As can be seen from Figure 11, the average DG system generation (June-September) closely resembles the generation on the native system peak day. However, a significant drop in generation is seen for 8/04/2020.

Figure 11



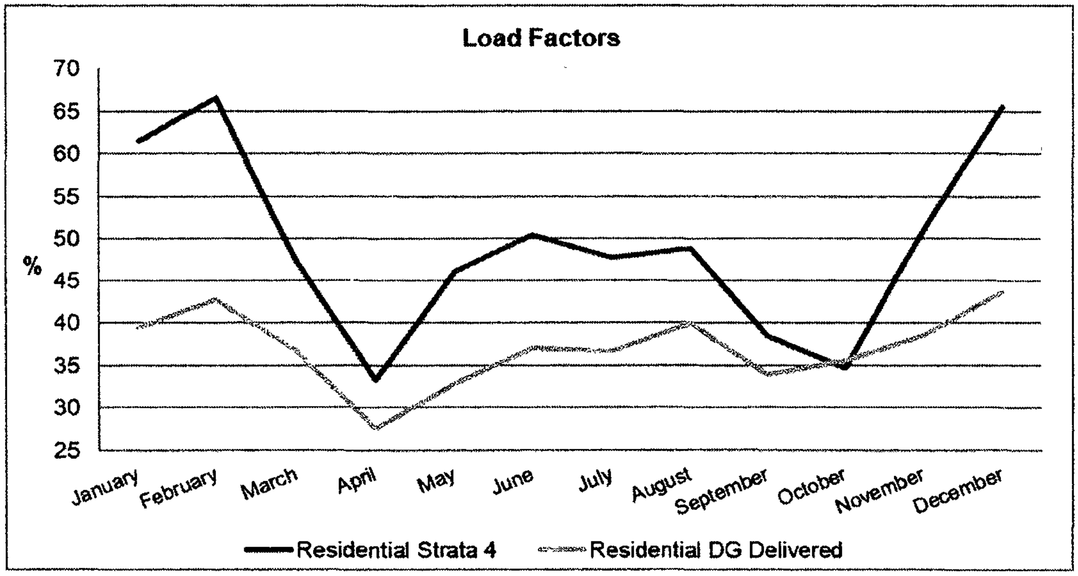
- Figure 12, below, looks at the average delivered energy to Texas residential DG customers over the same days chosen in Figure 11. We used the generation profile of 8/04/2020 to highlight a day where there was lower than average DG system production but still a high level of demand for several hours.
- As can be seen from Figure 12, EPE must serve the drop in the output of the DG systems on 8/04/2020 for several hours while the demand remains at high levels.

Figure 12



- The daily consumption patterns of residential DG customers are more volatile than residential customers due to their ramp up of energy consumption in the late afternoon to early evening hours.
- The volatility in residential DG customers' delivered load profile is highlighted by their monthly load factors shown in Figure 13.

Figure 13



- On average, residential DG customers decrease their energy usage, however, they still have high maximum demand values due to unfavorable DG production weather or increased demand as DG production falls. This relationship is summarized in Table 1, below.
- Table 1 shows that during 2020, the average residential DG customer was delivered 14% more energy than the average residential non-DG customer with a maximum demand that is 58% higher resulting in a much lower load factor.

Table 1
Average Load Characteristics of Residential Non-DG and Residential DG Delivered

	Units	December	July	Monthly Avg.
Energy				
Residential Non-DG	kWh	503	1,169	676
Residential DG Delivered	kWh	600	1,368	771
% Difference	%	19%	17%	14%
Demand				
Residential Non-DG	kW	1.09	3.00	1.82
Residential DG Delivered	kW	1.85	5.02	2.87
% Difference	%	70%	67%	58%
Load Factor				
Residential Non-DG	%	62	52	52
Residential DG Delivered	%	44	37	37
% Difference	%	-30%	-30%	-29%

- Table 2 shows that during 2020 the average residential DG customer, on a net energy basis, was billed for 37% less energy than the average residential non-DG customer but had a maximum demand that is 57% higher. This results in a much lower load factor than the delivered data shown in Table 1.
- Lower load factor customers are costlier to serve because they have a higher demand relative to their energy.

Table 2
Average Load Characteristics of Residential Non-DG and Residential DG Net

	Units	December	July	Monthly Avg.
Energy				
Residential Non-DG	kWh	503	1,169	676
Residential DG Net	kWh	296	1,108	425
% Difference	%	-41%	-5%	-37%
Demand				
Residential Non-DG	kW	1.09	3.00	1.82
Residential DG Net	kW	1.85	5.01	2.86
% Difference	%	70%	67%	57%
Load Factor				
Residential Non-DG	%	62	52	52
Residential DG Net	%	22	30	17
% Difference	%	-65%	-43%	-68%

Exhibit GN-3 Historical Weather in Las Cruces, NM and El Paso, TX

Las Cruces			El Paso			Percent Difference LC vs. EP		
Year	HDD	CDD	Year	HDD	CDD	Year	HDD	CDD
2006	2,471	2,226	2006	2,064	2,479	2006	20%	-10%
2007	2,479	2,163	2007	2,342	2,507	2007	6%	-14%
2008	2,677	1,848	2008	2,252	2,280	2008	19%	-19%
2009	2,924	1,892	2009	2,220	2,753	2009	32%	-31%
2010	3,197	1,858	2010	2,355	2,748	2010	36%	-32%
2011	3,124	2,093	2011	2,469	3,158	2011	27%	-34%
2012	2,663	2,011	2012	2,070	2,901	2012	29%	-31%
2013	3,204	1,986	2013	2,502	2,692	2013	28%	-26%
2014	2,641	1,972	2014	1,970	2,660	2014	34%	-26%
2015	2,915	1,951	2015	2,174	2,847	2015	34%	-31%
2016	2,650	2,021	2016	1,901	2,827	2016	39%	-29%
2017	2,258	2,022	2017	1,590	2,917	2017	42%	-31%
2018	2,641	2,335	2018	2,021	3,174	2018	31%	-26%
2019	2,715	2,103	2019	2,213	3,007	2019	23%	-30%
2020	2,674	2,389	2020	2,074	3,311	2020	29%	-28%
Average (2006-2020)	2,749	2,058	Average (2006-2020)	2,148	2,817	Average (2006-2020)	28%	-27%

Exhibit GN-3
Page 1 of 1

	Jan-20	Feb-20	Mar-20	Apr-20	May-20	Jun-20	Jul-20	Aug-20	Sep-20	Oct-20	Nov-20	Dec-20
<u>Actual Weather</u>												
El Paso												
HDD-2 Month Moving Average	529	476	302	94	10	0	0	0	8	53	137	415
CDD-2 Month Moving Average	0	0	6	88	312	540	684	739	540	276	114	13
Las Cruces												
HDD-2 Month Moving Average	634	576	417	201	52	0	0	0	12	71	207	490
CDD-2 Month Moving Average	0	0	0	26	166	379	550	613	431	176	49	1
<u>10-Year Avg Weather (2010-2019)</u>												
El Paso												
HDD-2 Month Moving Average	586	492	279	115	32	6	0	0	1	25	176	431
CDD-2 Month Moving Average	0	1	18	85	227	474	629	610	497	270	74	3
Las Cruces												
HDD-2 Month Moving Average	677	583	389	209	80	19	0	0	2	54	263	539
CDD-2 Month Moving Average	0	0	3	23	101	328	505	492	376	173	31	0

<u>Coefficients</u>	Jan-20	Feb-20	Mar-20	Apr-20	May-20	Jun-20	Jul-20	Aug-20	Sep-20	Oct-20	Nov-20	Dec-20
TXRT01- Residential	0 3563	0.2190	0 1706	0.3685	0.4622	0 6569	0 7807	0 7703	0 8679	0 7845	0 2627	0 2553
TXRT02- Small Commercial	0.0000	0 0000	0 0000	0.0000	5,241.8560	12,219 4500	14,974 7700	14,137.8000	16,755 8400	14,391 8400	0 0000	0.0000
TXRT22- Irrigation	0.0000	0.0000	0.0000	0.0000	280 0860	348 1630	322 4035	237 3163	284 6877	261 0433	0 0000	0 0000
TXRT24- General Service	0.0000	0.0000	0.0000	0.0000	44,066.9600	71,137.1200	76,311 2000	73,382 1400	92,216 0300	83,227.0000	0 0000	0.0000
TXRT31- Military	0.0000	0 0000	0 0000	0.0000	0 0000	8,239.5900	5,882.8370	5,854.8150	4,702 6700	0.0000	0.0000	0.0000
TXRT41- City & County	0.0000	0 0000	0 0000	0.0000	11,575.7800	7,596 4690	4,325 3720	11,922 5400	20,765 2200	15,916.6300	0 0000	0 0000
NMRT01- Residential	0 4118	0.2771	0 1902	0.2000	0.6100	0 7747	0.8597	0.8214	0.9523	0.8655	0.1529	0 2843
NMRT03- Small Commercial	0.0000	0 0000	0 0000	0.0000	5,828.5370	9,644 9530	10,875 2000	10,100 2200	12,301.1400	12,001 1900	0 0000	0.0000
NMRT04- General Service	0.0000	0 0000	0 0000	0.0000	9,050.8680	12,590 9900	13,795 1900	13,644.7300	16,768.0100	16,738.0500	0 0000	0 0000
NMRT05- Irrigation	0.0000	0 0000	0 0000	0 0000	12,534 9500	7,964 9510	4,484 6170	4,349 9760	6,010.2370	7,803.5930	0 0000	0 0000
NMRT07- City & County	0.0000	0 0000	0 0000	0 0000	3,372 1860	2,082 3820	1,890 6490	3,142 4580	6,681 3130	6,595.5300	0 0000	0 0000
NMRT08- Pumping	0.0000	0.0000	0.0000	0 0000	3,008.9830	2,276 6720	2,014 9380	1,564 8650	2,066.5030	2,071.3200	0 0000	0 0000
NMRT10-Military	0.0000	0.0000	0 0000	0.0000	0.0000	7,530 3020	8,147.1780	7,770.6550	6,351 9810	0.0000	0 0000	0.0000

Exhibit GN-4
Page 1 of 8

Actual kWh Sales	**Jan-20**	**Feb-20**	**Mar-20**	**Apr-20**	**May-20**	**Jun-20**	**Jul-20**	**Aug-20**	**Sep-20**	**Oct-20**	**Nov-20**	**Dec-20**
TXRT01- Residential	177,155,814	148,276,082	128,844,748	130,464,539	191,689,624	267,620,093	349,272,675	345,064,447	316,922,233	203,927,429	153,258,138	154,738,988
TXEVC - Texas Vehicle Charging	5,238	4,134	4,472	3,679	3,500	4,834	5,580	6,202	5,271	2,976	3,638	2,757
TXRTWH- Water Heating	660,758	596,867	538,484	521,063	437,834	387,162	355,056	304,103	334,796	343,543	388,402	480,307
TXRT02- Small General	21,489,577	19,985,463	18,439,925	16,498,453	19,354,371	26,048,173	32,074,373	30,453,255	30,067,449	22,820,031	19,447,982	19,141,008
TXRT07- Outdoor Recreational	396,194	481,713	519,720	185,984	170,435	178,533	231,790	236,810	316,387	405,967	269,564	266,178
TXRT08- Street Lighting	3,456,965	3,013,959	3,049,397	2,711,190	2,577,889	2,379,873	2,532,039	2,719,591	2,870,211	3,216,338	3,384,940	3,625,950
TXRT09- Traffic Signals	219,545	220,983	220,762	220,906	220,794	220,878	221,318	220,958	221,499	221,203	221,179	221,340
TXRT11TU- TOU Water Pumping	13,611,578	13,029,657	12,475,998	11,035,625	12,525,101	14,251,088	18,247,702	15,642,807	15,893,752	17,083,035	14,799,671	13,980,337
TXRT15- Electrolytic Refining	5,785,849	6,650,540	5,980,769	5,546,454	6,444,779	6,855,144	7,627,103	7,198,360	6,718,481	6,344,685	7,122,514	6,428,348
TXRT22- Irrigation	123,355	123,984	126,111	345,553	454,547	563,351	573,306	457,964	434,578	379,767	293,375	182,657
TXRT24- General Service	115,123,017	112,024,169	106,536,196	99,234,188	109,256,443	135,412,410	159,782,942	159,145,761	159,629,954	126,934,722	109,155,266	103,236,768
TXRT25- Large Power	48,183,898	49,955,281	50,651,520	47,813,986	43,442,490	51,978,600	56,097,228	56,830,774	60,196,005	52,914,684	52,656,358	46,982,065
TXRT26- Petroleum Refinery	24,034,719	13,557,945	27,966,732	29,139,642	25,572,459	28,569,538	28,447,442	26,436,437	28,661,653	27,874,329	26,844,396	27,536,427
TXRT28- Area Lighting	2,516,607	2,196,995	2,265,743	1,920,455	1,871,723	1,721,462	1,829,687	2,068,267	2,163,569	2,417,796	2,510,959	2,694,342
TXRT30- Electric Furnace	2,161,618	2,132,763	2,017,026	1,546,379	1,242,856	1,835,129	1,840,272	1,799,318	1,907,095	713,296	1,242,311	1,450,160
TXRT31- Military	26,143,505	24,885,838	21,449,603	20,947,662	21,724,279	25,416,125	24,378,414	25,451,643	22,431,633	21,496,801	20,775,347	25,263,103
TXRT34- Cotton Gin	266,375	11,336	11,068	8,297	5,502	6,047	5,683	6,109	6,794	7,469	487,287	774,413
TXRT38- Interruptible	25,830,551	22,408,237	27,677,443	22,502,042	24,859,444	37,484,392	39,339,029	40,045,615	38,954,181	22,529,693	11,701,250	22,525,863
TXRT41- City & County	17,117,101	18,623,835	17,558,117	12,088,561	12,383,474	16,286,973	19,599,892	21,116,117	22,568,682	16,774,390	13,809,786	13,253,885
	484,282,264	438,179,781	426,333,834	402,734,658	474,237,544	617,219,805	742,461,531	735,204,538	710,304,223	526,408,154	438,372,363	442,784,896
NMRT01- Residential	68,095,317	57,059,244	48,191,620	44,290,456	56,393,635	76,965,434	100,085,987	98,152,622	90,837,744	58,770,265	48,990,162	57,820,004
NMRT03- Small General	12,718,372	12,248,104	11,125,377	10,342,297	11,376,617	14,302,151	17,726,122	17,248,360	17,360,331	13,110,566	11,303,609	10,814,177
NMRT04- General Service	23,045,971	22,936,538	21,634,438	20,810,220	21,577,218	25,227,029	30,371,457	29,786,287	30,591,864	24,991,681	22,438,264	20,630,777
NMRT05- Irrigation	492,254	737,191	1,112,407	3,625,352	5,973,957	5,037,671	5,038,869	4,485,334	7,044,573	5,077,459	3,019,574	1,310,507
NMRT07- City & County	4,502,402	4,719,455	4,136,414	3,353,858	3,560,821	4,206,608	5,093,364	5,914,214	5,734,190	4,173,163	3,592,191	3,337,811
NMRT08- Pumping	2,745,588	2,816,328	2,559,065	2,881,349	3,441,442	3,853,605	4,592,623	4,010,038	4,177,761	3,372,822	2,669,551	2,610,252
NMRT09- Large Power	14,767,314	13,917,469	13,296,708	11,750,643	11,128,120	13,256,511	13,635,349	13,772,447	14,780,177	12,699,808	12,811,545	13,062,547
NMRT10- Military	10,679,686	10,061,520	9,724,153	8,154,340	9,078,218	12,119,526	12,678,086	12,055,978	12,372,076	9,949,292	8,454,106	9,673,885
NMRT11- Street Lighting	151,101	151,015	150,613	150,496	150,408	150,110	150,513	150,571	150,837	151,175	151,115	151,385
NMRT12- Area Lighting	428,781	429,743	443,987	429,775	430,803	430,980	431,955	430,383	433,392	428,422	428,462	428,265
NMRT19- Seasonal Agricultural	1,286,301	438,434	114,563	98,653	172,859	497,421	920,497	1,163,803	493,051	425,972	1,167,079	1,521,409
NMRT25- Outdoor Recreational	63,467	70,824	75,251	21,045	7,178	9,537	25,167	25,493	26,957	26,613	24,198	12,250
NMRT26- State University	1,501,563	1,954,267	2,229,000	2,223,005	1,627,046	2,688,532	3,110,740	3,056,719	2,929,658	2,520,114	1,836,570	1,804,130
NMRT29- Interruptible	585,255	576,847	559,329	557,551	462,037	596,262	669,743	702,168	717,908	765,390	850,947	721,488
	141,063,372	128,116,979	115,352,925	108,689,040	125,380,359	159,341,377	194,530,472	190,954,417	187,650,519	136,462,742	117,737,373	123,898,887

Number of Customers for UPC Models	**Jan-20**	**Feb-20**	**Mar-20**	**Apr-20**	**May-20**	**Jun-20**	**Jul-20**	**Aug-20**	**Sep-20**	**Oct-20**	**Nov-20**	**Dec-20**
TXRT01- Residential	294,970	295,248	295,813	296,204	297,024	297,782	298,614	299,201	300,014	300,444	300,839	301,303
NMRT01- Residential	88,894	88,987	89,114	89,219	89,434	89,598	89,804	89,945	90,197	90,328	90,433	90,533

Exhibit GN-4
Page 2 of 8

Description	Jan-20	Feb-20	Mar-20	Apr-20	May-20	Jun-20	Jul-20	Aug-20	Sep-20	Oct-20	Nov-20	Dec-20	Test Year Total
Unadjusted kWh													
TXRT01- Residential	177,155,814	148,276,082	128,844,748	130,464,539	191,689,624	267,620,093	349,272,675	345,064,447	316,922,233	203,927,429	153,258,138	154,738,988	2,567,234,810
TXEVC - Texas Vehicle Charging	5,238	4,134	4,472	3,679	3,500	4,834	5,580	6,202	5,271	2,976	3,638	2,757	52,281
TXRTWH- Water Heating	660,758	596,867	538,484	521,063	437,834	387,162	355,056	304,103	334,796	343,543	388,402	480,307	5,348,375
TXRT02- Small General	21,489,577	19,985,463	18,439,925	16,498,453	19,354,371	26,048,173	32,074,373	30,453,255	30,067,449	22,820,031	19,447,982	19,141,008	275,820,060
TXRT07- Outdoor Recreational	396,194	481,713	519,720	185,984	170,435	178,533	231,790	236,810	316,387	405,967	269,564	266,178	3,659,275
TXRT08- Street Lighting	3,456,965	3,013,959	3,049,397	2,711,190	2,577,889	2,379,873	2,532,039	2,719,591	2,870,211	3,216,338	3,384,940	3,625,950	35,538,342
TXRT09- Traffic Signals	219,545	220,983	220,762	220,906	220,794	220,878	221,318	220,958	221,499	221,203	221,179	221,340	2,651,365
TXRT11TU- TOU Water Pumping	13,611,578	13,029,657	12,475,998	11,035,625	12,525,101	14,251,088	18,247,702	15,642,807	15,893,752	17,083,035	14,799,671	13,980,337	172,576,351
TXRT15- Electrolytic Refining	5,785,849	6,650,540	5,980,769	5,546,454	6,444,779	6,855,144	7,627,103	7,198,360	6,718,481	6,344,685	7,122,514	6,428,348	78,703,026
TXRT22- Irrigation	123,355	123,984	126,111	345,553	454,547	563,351	573,306	457,964	434,578	379,767	293,375	182,657	4,058,548
TXRT24- General Service	115,123,017	112,024,169	106,536,196	99,234,188	109,256,443	135,412,410	159,782,942	159,145,761	159,629,954	126,934,722	109,155,266	103,236,768	1,495,471,836
TXRT25- Large Power	48,183,898	49,955,281	50,651,520	47,813,986	43,442,490	51,978,600	56,097,228	56,830,774	60,196,005	52,914,684	52,656,358	46,982,065	617,702,889
TXRT26- Petroleum Refinery	24,034,719	13,557,945	27,966,732	29,139,642	25,572,459	28,569,538	28,447,442	26,436,437	28,661,653	27,874,329	26,844,396	27,536,427	314,641,719
TXRT28- Area Lighting	2,516,607	2,196,995	2,265,743	1,920,455	1,871,723	1,721,462	1,829,687	2,068,267	2,163,569	2,417,796	2,510,959	2,694,342	26,177,605
TXRT30- Electric Furnace	2,161,618	2,132,763	2,017,026	1,546,379	1,242,856	1,835,129	1,840,272	1,799,318	1,907,095	713,296	1,242,311	1,450,160	19.888,223
TXRT31- Military	26,143,505	24,885,838	21,449,603	20,947,662	21,724,279	25,416,125	24,378,414	25,451,643	22,431,633	21,496,801	20,775,347	25,263,103	280,363,953
TXRT34- Cotton Gin	266,375	11,336	11,068	8,297	5,502	6,047	5,683	6,109	6,794	7,469	487,287	774,413	1,596,380
TXRT38- Interruptible	25,830,551	22,408,237	27,677,443	22,502,042	24,859,444	37,484,392	39,339,029	40,045,615	38,954,181	22,529,693	11,701,250	22,525,863	335,857,740
TXRT41- City & County	17,117,101	18,623,835	17,558,117	12,088,561	12,383,474	16,286,973	19,599,892	21,116,117	22,568,682	16,774,390	13,809,786	13,253,885	201,180,813
Total Unadjusted kWh	484,282,264	438,179,781	426,333,834	402,734,658	474,237,544	617,219,805	742,461,531	735,204,538	710,304,223	526,408,154	438,372,363	442,784,896	6,438,523,591

Exhibit GN-4
Page 3 of 8

Description	Jan-20	Feb-20	Mar-20	Apr-20	May-20	Jun-20	Jul-20	Aug-20	Sep-20	Oct-20	Nov-20	Dec-20	Test Year Total
Weather Adjustments to kWh													
TXRT01- Residential	5,990,911	1,034,388	(1 160 881)	2,292,150	(11 669 460)	(12 911 401)	(12.822 251)	(29 732 257)	(11.196 303)	(1 414 125)	3,082,057	1,230,970	(67,276.201)
TXEVC - Texas Vehicle Charging	0	0	0	0	0	0	0	0	0	0	0	0	0
TXRTWH- Water Heating	0	0	0	0	0	0	0	0	0	0	0	0	0
TXRT02- Small General	0	0	0	0	(345,558)	(806,484)	(823.612)	(1,823 776)	(720.501)	(86,351)	0	0	(4.706.282)
TXRT07- Outdoor Recreational	0	0	0	0	0	0	0	0	0	0	0	0	0
TXRT08- Street Lighting	0	0	0	0	0	0	0	0	0	0	0	0	0
TXRT09- Traffic Signals	0	0	0	0	0	0	0	0	0	0	0	0	0
TXRT11TU- TOU Water Pumping	0	0	0	0	0	0	0	0	0	0	0	0	0
TXRT15- Electrolytic Refining	0	0	0	0	0	0	0	0	0	0	0	0	0
TXRT22- Irrigation	0	0	0	0	(23,807)	(22,979)	(17,732)	(30.614)	(12 242)	(1.566)	0	0	(108.940)
TXRT24- General Service	0	0	0	0	(3 745 692)	(4.695.050)	(4 197.116)	(9 466.296)	(3.965.289)	(499.362)	0	0	(26,568.805)
TXRT25- Large Power	0	0	0	0	0	0	0	0	0	0	0	0	0
TXRT26- Petroleum Refinery	0	0	0	0	0	0	0	0	0	0	0	0	0
TXRT28- Area Lighting	0	0	0	0	0	0	0	0	0	0	0	0	0
TXRT30- Electric Furnace	0	0	0	0	0	0	0	0	0	0	0	0	0
TXRT31- Military	0	0	0	0	0	(543,813)	(323,556)	(755.271)	(202 215)	0	0	0	(1.824.855)
TXRT34- Cotton Gin	0	0	0	0	0	0	0	0	0	0	0	0	0
TXRT38- Interruptible	0	0	0	0	0	0	0	0	0	0	0	0	0
TXRT41- City & County	0	0	0	0	(983,941)	(501 367)	(237,895)	(1.538.008)	(892,904)	(95,500)	0	0	(1,249,616)
Total Weather Adjustment	5,990,911	1,034,388	(1,160,881)	2,292,150	(16,868,458)	(19,481.093)	(18,422 163)	(43,346 221)	(16,989.455)	(2,096 904)	3,082,057	1,230,970	(104.734.699)

Exhibit GN-4
Page 4 of 8

Description	Jan-20	Feb-20	Mar-20	Apr-20	May-20	Jun-20	Jul-20	Aug-20	Sep-20	Oct-20	Nov-20	Dec-20	Test Year Total
Weather Adjusted kWh													
TXRT01- Residential	183,146,725	149,310,470	127,683,867	132,756,689	180,020,164	254,708,692	336,450,424	315,332,190	305,725,930	202,513,304	156,340,195	155,969,958	2,499,958,609
TXEVC - Texas Vehicle Charging	5,238	4,134	4,472	3,679	3,500	4,834	5,580	6,202	5,271	2,976	3,638	2,757	52,281
TXRTWH- Water Heatıng	660,758	596,867	538,484	521,063	437,834	387,162	355,056	304.103	334,796	343,543	388,402	480,307	5,348,375
TXRT02- Small General	21,489,577	19,985,463	18,439,925	16,498,453	18,908,813	25,241,689	31,250,761	28,629,479	29,346,948	22,733,680	19,447,982	19,141,008	271,113,778
TXRT07- Outdoor Recreational	396,194	481,713	519,720	185,984	170,435	178,533	231,790	236,810	316,387	405,967	269,564	266,178	3,659,275
TXRT08- Street Lighting	3,456,965	3,013,959	3,049,397	2,711,190	2,577,889	2,379,873	2,532,039	2,719.591	2,870,211	3,216,338	3,384,940	3,625,950	35,538,342
TXRT09- Traffic Sıgnals	219,545	220,983	220,762	220,906	220,794	220,878	221,318	220,958	221,499	221,203	221,179	221,340	2,651,365
TXRT11TU- TOU Water Pumpıng	13,611,578	13,029,657	12,475,998	11,035,625	12,525,101	14,251,088	18,247,702	15,642,807	15,893,752	17,083,035	14,799,671	13,980,337	172,576,351
TXRT15- Electrolytic Refinıng	5,785,849	6,650,540	5,980,769	5,546,454	6,444,779	6,855,144	7,627,103	7,198,360	6,718,481	6,344,685	7,122,514	6,428,348	78,703,026
TXRT22- Irrigatıon	123,355	123,984	126,111	345,553	430,740	540,372	555,574	427,350	422,336	378,201	293,375	182,657	3,949,608
TXRT24- General Servıce	115,123,017	112,024,169	106,536,196	99,234,188	105,510,751	130,717,360	155,585,826	149,679,465	155,664,665	126,435,360	109,155,266	103,236,768	1,468,903,031
TXRT25- Large Power	48,183,898	49,955,281	50,651,520	47,813,986	43,442,490	51,978,600	56,097,228	56,830,774	60,196,005	52,914,684	52,656,358	46,982,065	617,702,889
TXRT26- Petroleum Refinery	24,034,719	13,557,945	27,966,732	29,139,642	25,572,459	28,569,538	28,447,442	26,436.437	28,661,653	27,874,329	26,844,396	27,536,427	314,641,719
TXRT28- Area Lıghting	2,516,607	2,196,995	2,265,743	1,920,455	1,871,723	1,721,462	1,829,687	2,068,267	2,163,569	2,417,796	2,510,959	2,694,342	26,177,605
TXRT30- Electrıc Furnace	2,161,618	2,132,763	2,017,026	1,546,379	1,242,856	1,835,129	1,840,272	1,799.318	1,907,095	713,296	1,242,311	1,450,160	19,888,223
TXRT31- Mılıtary	26,143,505	24,885,838	21,449,603	20,947,662	21,724,279	24,872,312	24.054,858	24,696,372	22,229,418	21,496,801	20,775,347	25,263,103	278,539,098
TXRT34- Cotton Gın	266,375	11,336	11,068	8,297	5,502	6,047	5,683	6,109	6,794	7,469	487,287	774,413	1,596,380
TXRT38- Interruptıble	25,830,551	22,408,237	27,677,443	22,502,042	24,859,444	37,484,392	39,339,029	40,045,615	38,954,181	22,529,693	11.701,250	22,525,863	335,857,740
TXRT41- Cıty & County	17,117,101	18,623,835	17,558,117	12,088,561	11,399,533	15,785,606	19,361,997	19,578,109	21,675,778	16,678,890	13,809,786	13,253,885	196,931,197
Total Weather Adjusted kWh	490,273,175	439,214,169	425,172,953	405,026,808	457,369,086	597,738,712	724,039,368	691,858,317	693,314,768	524,311,250	441,454,420	444,015,866	6,333,788,892

Exhibit GN-4
Page 5 of 8

Description	Jan-20	Feb-20	Mar-20	Apr-20	May-20	Jun-20	Jul-20	Aug-20	Sep-20	Oct-20	Nov-20	Dec-20	Test Year Total
Unadjusted kWh													
NMRT01- Residential	68,095,317	57,059,244	48,191,620	44,290,456	56,393,635	76,965,434	100,085,987	98,152,622	90,837,744	58,770,265	48,990,162	57,820,004	805,652,490
NMRT03- Small General	12,718,372	12,248,104	11,125,377	10,342,297	11,376,617	14,302,151	17,726,122	17,248,360	17,360,331	13,110,566	11,303,609	10,814,177	159,676,083
NMRT04- General Service	23,045,971	22,936,538	21,634,438	20,810,220	21,577,218	25,227,029	30,371,457	29,786,287	30,591,864	24,991,681	22,438,264	20,630,777	294,041,744
NMRT05- Irrigation	492,254	737,191	1,112,407	3,625,352	5,973,957	5 037,671	5,038,869	4,485,334	7,044,573	5,077,459	3,019,574	1,310,507	42,955,148
NMRT07- City & County	4,502,402	4,719,455	4,136,414	3,353,858	3,560,821	4,206,608	5,093,364	5,914,214	5,734,190	4,173,163	3,592,191	3,337,811	52,324,491
NMRT08- Pumping	2,745,588	2,816,328	2,559,065	2,881,349	3,441,442	3,853,605	4,592,623	4,010,038	4,177,761	3,372,822	2,669,551	2,610,252	39,730,424
NMRT09- Large Power	14,767,314	13,917,469	13,296,708	11,750,643	11,128,120	13,256,511	13,635,349	13,772,447	14,780,177	12,699,808	12,811,545	13,062,547	158,878,638
NMRT10- Military	10,679,686	10,061,520	9,724,153	8,154,340	9,078,218	12,119,526	12,678,086	12,055,978	12,372,076	9,949,292	8,454,106	9,673,885	125,000,866
NMRT11- Street Lighting	151,101	151,015	150,613	150,496	150,408	150,110	150,513	150,571	150,837	151,175	151,115	151,385	1,809,339
NMRT12- Area Lighting	428,781	429,743	443,987	429,775	430,803	430,980	431,955	430,383	433,392	428,422	428,462	428,265	5,174,948
NMRT19- Seasonal Agricultural	1,286,301	438,434	114,563	98,653	172,859	497,421	920,497	1,163,803	493,051	425,972	1,167,079	1,521,409	8,300,042
NMRT25- Outdoor Recreational	63,467	70,824	75,251	21,045	7,178	9,537	25,167	25,493	26,957	26,613	24,198	12,250	387,980
NMRT26- State University	1,501,563	1,954,267	2,229,000	2,223,005	1,627,046	2,688,532	3,110,740	3,056,719	2,929,658	2,520,114	1,836,570	1,804,130	27,481,344
NMRT29- Interruptible	585,255	576,847	559,329	557,551	462,037	596,262	669,743	702,168	717,908	765,390	850,947	721,488	7,764,925
Total Unadjusted kWh	141,063,372	128,116,979	115,352,925	108,689,040	125,380,359	159,341,377	194,530,472	190,954,417	187,650,519	136,462,742	117,737,373	123,898,887	1,729,178,462

Exhibit GN-4
Page 6 of 8

Description	Jan-20	Feb-20	Mar-20	Apr-20	May-20	Jun-20	Jul-20	Aug-20	Sep-20	Oct-20	Nov-20	Dec-20	Test Year Total
Weather Adjustments to kWh													
NMRT01- Residential	1,574,215	172,598	(474.461)	142,753	(3,546.017)	(3.539.912)	(3 474,344)	(8 940,048)	(4,724 208)	(234,545)	774,151	1,261,139	(21.008.678)
NMRT03- Small General	0	0	0	0	(378,855)	(491 893)	(489,384)	(1.222,127)	(676.563)	(36,004)	0	0	(3.294,824)
NMRT04- General Service	0	0	0	0	(588.306)	(642.140)	(620 784)	(1 651 012)	(922,241)	(50 214)	0	0	(4 474.697)
NMRT05- Irrigation	0	0	0	0	(814.772)	(406,213)	(201.808)	(526.347)	(330 563)	(23.411)	0	0	(2.303.113)
NMRT07- City & County	0	0	0	0	(219.192)	(106 201)	(85.079)	(380,237)	(367 472)	(19,787)	0	0	(1.177.969)
NMRT08- Pumping	0	0	0	0	(195,584)	(116.110)	(90,672)	(189,349)	(113.658)	(6,214)	0	0	(711,587)
NMRT09- Large Power	0	0	0	0	0	0	0	0	0	0	0	0	0
NMRT10- Military	0	0	0	0	0	(384,045)	(366.623)	(940.249)	(349,359)	0	0	0	(2 040.277)
NMRT11- Street Lighting	0	0	0	0	0	0	0	0	0	0	0	0	0
NMRT12- Area Lighting	0	0	0	0	0	0	0	0	0	0	0	0	0
NMRT19- Seasonal Agricultural	0	0	0	0	0	0	0	0	0	0	0	0	0
NMRT25- Outdoor Recreational	0	0	0	0	0	0	0	0	0	0	0	0	0
NMRT26- State University	0	0	0	0	0	0	0	0	0	0	0	0	0
NMRT29- Interruptible	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Weather Adjustment	1,574,215	172,598	(474.461)	142,753	(5.742.726)	(5,686.515)	(5 328.694)	(13.849.369)	(7 484,063)	(370.174)	774,151	1,261,139	(35 011 145)

Exhibit GN-4
Page 7 of 8

Description	Jan-20	Feb-20	Mar-20	Apr-20	May-20	Jun-20	Jul-20	Aug-20	Sep-20	Oct-20	Nov-20	Dec-20	Test Year Total
Weather Adjusted kWh													
NMRT01- Residential	69,669,532	57,231,842	47,717,159	44,433,209	52,847,618	73,425,522	96,611,643	89,212,574	86,113,536	58,535,720	49,764,313	59,081,143	784,643,812
NMRT12- Area Lighting	428,781	429,743	443,987	429,775	430,803	430,980	431,955	430,383	433,392	428,422	428,462	428,265	5,174,948
NMRT03- Small General	12,718,372	12,248,104	11,125,377	10,342,297	10,997,762	13,810,258	17,236,738	16,026,233	16,683,768	13,074,562	11,303,609	10,814,177	156,381,259
NMRT04- General Service	23,045,971	22,936,538	21,634,438	20,810,220	20,988,912	24,584,889	29,750,673	28,135,275	29,669,623	24,941,467	22,438,264	20,630,777	289,567,047
NMRT05- Irrigation	492,254	737,191	1,112,407	3,625,352	5,159,185	4,631,458	4,837,061	3,958,987	6,714,010	5,054,048	3,019,574	1,310,507	40,652,035
NMRT07- City & County	4,502,402	4,719,455	4,136,414	3,353,858	3,341,629	4,100,407	5,008,285	5,533,977	5,366,718	4,153,376	3,592,191	3,337,811	51,146,522
NMRT08- Pumping	2,745,588	2,816,328	2,559,065	2,881,349	3,245,858	3,737,495	4,501,951	3,820,689	4,064,103	3,366,608	2,669,551	2,610,252	39,018,837
NMRT09- Large Power	14,767,314	13,917,469	13,296,708	11,750,643	11,128,120	13,256,511	13,635,349	13,772,447	14,780,177	12,699,808	12,811,545	13,062,547	158,878,638
NMRT11- Street Lighting	151,101	151,015	150,613	150,496	150,408	150,110	150,513	150,571	150,837	151,175	151,115	151,385	1,809,339
NMRT19- Seasonal Agricultural	1,286,301	438,434	114,563	98,653	172,859	497,421	920,497	1,163,803	493,051	425,972	1,167,079	1,521,409	8,300,042
NMRT25- Outdoor Recreational	63,467	70,824	75,251	21,045	7,178	9,537	25,167	25,493	26,957	26,613	24,198	12,250	387,980
NMRT29- Interruptible	585,255	576,847	559,329	557,551	462,037	596,262	669,743	702,168	717,908	765,390	850,947	721,488	7,764,925
NMRT10- Military	10,679,686	10,061,520	9,724,153	8,154,340	9,078,218	11,735,481	12,311,463	11,115,729	12,022,717	9,949,292	8,454,106	9,673,885	122,960,589
NMRT26- State University	1,501,563	1,954,267	2,229,000	2,223,005	1,627,046	2,688,532	3,110,740	3,056,719	2,929,658	2,520,114	1,836,570	1,804,130	27,481,344
Total Weather Adjusted kWh	142,637,587	128,289,577	114,878,464	108,831,793	119,637,633	153,654,862	189,201,778	177,105,048	180,166,456	136,092,568	118,511,524	125,160,026	1,694,167,317

Exhibit GN-4
Page 8 of 8

Exhibit GN-5 Test Year Degree Days Vs. Normal Weather Degree Days

Line No.	Las Cruces, NM													
1		2020	2020	2020	2020	2020	2020	2020	2020	2020	2020	2020	2020	Test Year
2		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
3														
4	Cooling Degree Days - Base 65 deg. F. Las Cruces, NM													
5	Actual CDD	0	0	0	52	279	479	620	605	257	95	2	0	2,389
6	10 year average (2010-2019)	0	0	5	41	161	495	514	468	284	61	1	0	2,030
7														
8	Heating Degree Days - Base 65 deg. F. Las Cruces, NM													
9	Actual HDD	617	534	299	103	0	0	0	0	23	118	296	684	2,674
10	10 year average (2010-2019)	684	481	296	122	37	0	0	0	3	104	421	657	2,805
11														
12	El Paso, TX													
13		2020	2020	2020	2020	2020	2020	2020	2020	2020	2020	2020	2020	Test Year
14		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
15														
16	Cooling Degree Days - Base 65 deg. F. El Paso, Texas													
17	Actual CDD	0	0	12	164	460	620	748	729	350	202	26	0	3,311
18	10 year average (2010-2019)	0	2	33	137	317	632	626	594	399	142	6	0	2,888
19														
20	Heating Degree Days - Base 65 deg. F. El Paso, Texas													
21	Actual HDD	515	436	168	19	0	0	0	0	15	91	183	647	2,074
22	10 year average (2010-2019)	603	380	178	51	12	0	0	0	1	48	304	557	2,134

Note: Weather data is in calendar month form and has not been adjusted for billing cycles.

Exhibit GN-5
Page 1 of 1

APPENDIX A
EL PASO ELECTRIC COMPANY
2021-2030 DEMAND AND ENERGY FORECAST

Summary

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

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

APPENDIX A
EL PASO ELECTRIC COMPANY
2031-2040 DEMAND AND ENERGY FORECAST

Summary

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

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

DOCKET NO. ________

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

DIRECT TESTIMONY

OF

ADRIAN HERNANDEZ

FOR

EL PASO ELECTRIC COMPANY

JUNE 2021

EXECUTIVE SUMMARY

Mr. Adrian Hernandez is a Senior Rate Analyst in El Paso Electric Company's ("EPE" or "Company") Regulatory Affairs Department. In his testimony, Mr. Hernandez describes the cost-of-service model that EPE employs to produce the Texas jurisdictional cost-of-service study, class cost-of-service study, and demand, energy, and customer components study. The cost of service supports EPE's revenue requirement, rate design proposals, and the development of new baselines for the Distribution Cost Recovery Factor ("DCRF"), the Transmission Cost Recovery Factor ("TCRF"), and the Generation Cost Recovery Rider ("GCRR").

TABLE OF CONTENTS

EXHIBITS

I. Introduction and Qualifications

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

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

Q. HOW ARE YOU EMPLOYED?

A. I am employed by El Paso Electric Company ("EPE" or the "Company") as a Senior Rate Analyst.

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL AND PROFESSIONAL QUALIFICATIONS.

A. I graduated from the University of Texas at Austin with a Bachelor of Business Administration in Accounting and a minor in Finance in 2007. I later earned a Master of Accountancy degree from The University of Texas at El Paso in 2011. In 2014, I received a graduate certificate from New Mexico State University ("NMSU") in Public Utility Regulation & Economics. In 2015, I became a Certified Public Accountant licensed in the state of Texas. I continued my studies at NMSU and received a Master of Business Administration degree in 2017. Throughout my years at EPE, I have regularly attended professional development seminars to stay up-to-date on utility industry topics.

After earning my bachelor's degree in 2007, I was hired by BearingPoint Inc., in Washington, D.C., as a Business Analyst. In 2008, I returned to El Paso where I was employed as a Cost Accountant for Helen of Troy Limited. My career in the utility industry began in 2009, when I accepted a Regulatory Accountant position with EPE. In 2014, I became an Associate Analyst with EPE's Regulatory Affairs department and was promoted to Staff Rate Analyst in 2015. In 2016, I was promoted to my current position, Senior Rate Analyst.

Q. PLEASE DESCRIBE YOUR CURRENT RESPONSIBILITIES WITH EPE.

A. As a Senior Rate Analyst in the Rate Research group, my responsibilities are to perform or assist in the preparation of economic, statistical, cost, and rate design studies; to develop models and methodologies for cost of service, profitability, and pricing studies;

and to perform annualization and cost-of-service studies, rate design, and revenue forecasts. I have also participated in regulatory filings related to energy efficiency, fuel rates, and advanced metering.

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

A. Yes, I have testified on behalf of EPE in cases before the Public Utility Commission of Texas ("Commission" or "PUCT") and the New Mexico Public Regulation Commission.

II. Purpose of Testimony

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to present EPE's cost-of-service studies. EPE's cost-of-service studies consist of the jurisdictional cost-of-service ("JCOS") study; class cost-of-service ("CCOS") study; and demand, energy, and customer ("DEC") component costs ("DEC Study"). Those studies are used to develop EPE's proposed rates as explained in the direct testimony of EPE witness Manuel Carrasco.

I will also present testimony to reset the baselines for EPE's Distribution Cost Recovery Factor ("DCRF") and Transmission Cost Recovery Factor ("TCRF").

Finally, I support the Company's proposal to establish new baseline values for a Generation Cost Recovery Rider ("GCRR").

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

A. Exhibit AH-1 lists the schedules I sponsor or co-sponsor.

Q. ARE YOU SPONSORING ANY EXHIBITS IN YOUR TESTIMONY?

A. Yes. I am sponsoring the following exhibits, which are attached to this testimony.

- Exhibit AH-1 - Sponsored Schedules
- Exhibit AH-2 - Monthly System Peak Demands
- Exhibit AH-3 - Jurisdictional Cost-of-Service Study Summary
- Exhibit AH-4 - Class Cost-of-Service Study Summary
- Exhibit AH-5 - Distribution Cost Recovery Factor Baseline

- Exhibit AH-6 - Transmission Cost Recovery Factor Baseline
- Exhibit AH-7 - Generation Cost Recovery Rider Baselines

Q. WERE THE SCHEDULES AND EXHIBITS YOU ARE SPONSORING OR CO-SPONSORING PREPARED BY YOU OR UNDER YOUR DIRECT SUPERVISION?

A. Yes, they were.

III. Cost-of-Service Study Overview

Q. IS A COST-OF-SERVICE STUDY REQUIRED AS PART OF A GENERAL RATE CASE FILING?

A. Yes. The Commission's Electric Utility Rate Filing Package for Generating Utilities ("RFP") requires utilities with non-Texas jurisdictional sales to file a schedule summarizing the utility's overall cost of service on a Texas retail basis by use of a jurisdictional allocation study in support of Schedules A and B. The fully allocated CCOS study is included in the P Schedules of the RFP. The purpose of a cost-of-service study is to appropriately allocate costs to customer groups using cost causation principles to ensure fair pricing of electric service. The results of the JCOS study are used to develop the CCOS study. EPE witness Carrasco takes the results of the CCOS study and applies them for rate design in his testimony.

Q. WHAT DATA ARE USED IN EPE'S COST-OF-SERVICE STUDIES?

A. The cost-of-service studies use data based on EPE's Test Year ended December 31, 2020. The historical Test Year data were compiled from EPE's accounting records, which are maintained in accordance with the Federal Energy Regulatory Commission ("FERC") Uniform System of Accounts, as prescribed by the Commission.

As discussed in the testimony of EPE witness Jennifer I. Borden, the historical Test Year was adjusted for known and measurable changes to obtain adjusted total Company amounts.

Q. WHAT ARE THE TYPICAL STEPS INVOLVED IN DEVELOPING A

COST-OF-SERVICE STUDY?

A. The cost-of-service study typically consists of three steps: functionalization, classification, and assignment. Each of these steps is described below.

Q. PLEASE DESCRIBE COST FUNCTIONALIZATION.

A. After all the individual cost components representing the total revenue requirement have been collected for the cost-of-service study; the components are separated according to the function or physical service they provide. These functions are:

- Production – costs associated with the production of energy and capacity, including purchased power;
- Transmission – costs associated with the high voltage system that transports the power to load centers;
- Distribution – costs associated with distributing the energy from the transmission system to the end users;
- Customer Service – costs associated with providing service to the customer–e.g., meter reading, billing, etc.; and
- Administrative and General – common costs, such as management, buildings, software, support services, etc., which are incurred to support the core functions of electric service listed above.

Q. PLEASE DESCRIBE COST CLASSIFICATION.

A. The second step is to classify the functionalized costs according to the characteristics of the utility service being provided. The three principal cost classifications are demand-related costs, energy-related costs, and customer-related costs.

- Demand-related costs are those fixed costs that are related to the kilowatt ("kW") demand that the customers place on the system at any point in time. These costs vary with the maximum demand imposed on the various components (facilities) of the power system by the customers.
- Energy-related costs are those costs that are related to the kilowatt-hours ("kWh") of energy that the customer utilizes over time. These costs, primarily fuel, vary with the overall quantity of energy consumed.

- Customer-related costs are those costs incurred as a result of the number of customers on the system but irrespective of the customer's load. These costs, such as meters and billing, are incurred to serve individual customers.

Q. ONCE THE COST OF SERVICE IS FUNCTIONALIZED AND CLASSIFIED, HOW ARE COSTS ASSIGNED?

A. After functionalization and classification, responsibility for each cost is then determined through allocation or direct assignment. The process of allocating costs starts with using operating and accounting data to develop allocation factors by rate class that correspond to each cost classification factor (demand, energy, and customer). These allocation factors are then calculated as percentages (i.e., Texas jurisdiction or residential class as a percent of total). The allocation factors are then applied to specific costs and rate-base items to derive EPE's cost of service for each jurisdiction or rate class. If costs were incurred to benefit a clearly identifiable jurisdiction or rate class, a direct assignment of that cost is made.

Q. HAS EPE MADE ANY CHANGES TO THE COST-OF-SERVICE MODEL SINCE ITS LAST TEXAS BASE-RATE CASE, DOCKET NO. 46831[1]?

A. No. EPE continues to use the software module called PowerPlan Regulatory Management Suite ("RMS") that integrates with EPE's existing general ledger platform. This integration allows the Company to derive information from its books at a greater level of detail through the use of a regulatory ledger. The regulatory ledger is presented using "Reg Accounts" which are subaccounts under the FERC account level that provide a more granular level of detail of cost captured in EPE's accounting system.

RMS also is a proprietary server-based application that produces a working spreadsheet version in Microsoft Excel format of EPE's cost-of-service model.

Q. HAS THE OVERALL METHODOLOGY OF THE COST-OF-SERVICE MODEL CHANGED WITH THE USE OF RMS?

[1] Application of El Paso Electric Company to Change Rates, Docket No. 46831, Order (Dec. 18, 2017).

A. No, the overall methodology has not changed. EPE continues to use the National Association of Regulatory Utility Commissioners' ("NARUC") "Electric Utility Cost Allocation Manual" ("NARUC Manual") as a general guide for its cost of service. RMS provides a more efficient and detailed means of developing the cost-of-service studies.

While EPE's overall approach will not change, some new cost allocation modifications will be proposed in this filing. I discuss these modifications in more detail later in my testimony.

IV. Jurisdictional Cost-of-Service Study

Q. WHY IS IT NECESSARY FOR EPE TO PRODUCE A JURISDICTIONAL COST-OF-SERVICE STUDY?

A. As described in the direct testimony of EPE witness James Schichtl, EPE provides service to customers in west Texas and southern New Mexico. To provide the revenue and cost data for EPE's Texas service area that is required for preparation of several schedules, it is necessary to first produce a jurisdictional cost-of-service study for the Texas retail jurisdiction. The JCOS serves as the foundation for the class cost-of-service study in which the revenue requirements are assigned to each rate class. The class cost-of-service study is discussed later in my testimony.

To meet the RFP requirements, a JCOS is produced on a test year basis, adjusted for known and measurable changes. Therefore, the Test Year JCOS includes all the adjustments discussed in the testimony of EPE witness Borden. Schedule A-3 provides the effect of each adjustment on a total company basis. The JCOS study begins with total Company amounts which are then allocated to the Texas jurisdiction as described below.

Q. WHAT IS REQUIRED TO PRODUCE A JCOS FOR THE TEXAS JURISDICTION?

A. After the functionalization process is complete, jurisdictional responsibility for each cost is then determined through direct or indirect allocations. When a cost benefits more than one of EPE's jurisdictions, it is allocated amongst jurisdictions based on cost causation principles. Operating data are used to develop allocation factors by jurisdictions (i.e., "Texas" and "Other") that correspond to each cost classification factor (demand, energy, and customers). Primary allocators used in the JCOS consist of a four-coincident peak average & excess ("4CP-A&E") allocation factor and a four-coincident peak ("4CP") allocation factor for demand-related costs; an energy allocation factor for energy-related costs; and a customer allocation factor for customer-related costs. A composite labor allocation factor is used to allocate most administrative and general costs. These allocation factors are calculated as percentages (i.e., Texas retail as a percent of Total Company) which are then applied to specific revenue, expense, and rate base items to derive EPE's cost of service for Texas and Other jurisdictions. This allocation is then summarized by the cost-of-service model and forms the basis for allocating items that are not specifically functionalized, such as accumulated deferred income taxes. If costs were incurred to benefit a clearly identifiable jurisdiction, a direct allocation of that component is made (e.g., distribution substations).

Q. WHAT ARE DIRECTLY ASSIGNED COSTS?

A. When a cost is incurred on behalf of only one jurisdiction, that cost is directly assigned to that jurisdiction. Directly assigned costs include regulatory assets and items affected by the actions of specific regulatory bodies. For example, EPE is required to pay annually to the State of Texas a gross receipts assessment to defray the cost of the PUCT. This fee relates directly to the Texas jurisdiction, and it applies solely to Texas customers. Therefore, in this example, these costs are directly assigned to the Texas jurisdiction in the JCOS.

Q. WHAT TYPES OF ALLOCATORS ARE USED IN THE JURISDICTIONAL COST-OF-SERVICE STUDY?

A. The RMS model utilizes two general types of allocators: "imported" or external allocators, and "dynamic" or internal allocators. Imported allocators include energy, demand, and customer allocators. In contrast, a dynamic allocator is derived from accounts that have already been allocated using a combination of allocators; examples include Net Plant and Labor. Using Net Plant as an example, the functionalized costs of plant-in-service costs net of accumulated depreciation are each initially allocated to each jurisdiction using imported allocators, as prescribed by the NARUC Manual. The summed-up results are then used internally to develop a Net Plant dynamic allocator

("NETPLT"). The NETPLT allocator is used to allocate costs such as deferred income taxes.

Q. HOW ARE THE JURISDICTIONAL ENERGY, DEMAND, AND CUSTOMER ALLOCATION FACTORS DEVELOPED?

A. EPE witness George Novela develops the demand and energy allocators as discussed in his testimony. The data for the customer allocators is provided by EPE witness Carrasco. These external allocators are then input into RMS where the model can be run to produce the allocated results.

Q. WERE ANY ADJUSTMENTS MADE TO THE ENERGY AND DEMAND ALLOCATION FACTORS FOR DEDICATED SOLAR FACILITIES?

A. Yes. Consistent with prior EPE rate case filings, adjustments were made to the jurisdictional energy and the production demand allocation factors to reflect purchased power agreements ("PPAs") specific to certain solar facilities in Texas and New Mexico. EPE witness Novela addresses those adjustments in more detail in his Direct Testimony.

Q. HOW ARE COSTS OF THOSE DEDICATED SOLAR PPAS RECOVERED FROM CUSTOMERS?

A. Energy from four purchased power contracts in New Mexico that were entered into in order to meet renewable portfolio standard ("RPS") requirements are recovered directly from New Mexico customers through the RPS Cost Rider Rate No. 18. In Texas, EPE recovers the costs of energy from the ten-MW PSEG Solar Energy Center ("Newman Solar PPA") from Texas customers through the fixed fuel factor and the Texas Community Solar program tariff.

Q. HOW ARE COSTS FROM COMPANY-OWNED SOLAR GENERATION FACILITIES TREATED IN THE JURISDICTIONAL COST OF SERVICE?

A. EPE directly assigns costs of solar facilities that are specifically dedicated to a certain state or jurisdiction. For example, the costs of the Company-owned solar generation facility located at the Rio Grande Generating Station, identified as "NMSOL" in the

JCOS study, are directly assigned to New Mexico ("Other" in the JCOS). While costs identified as "TXSOL" are directly assigned to Texas.

Furthermore, EPE does not allocate any costs of Company-owned solar generation facilities specifically dedicated to a single customer (i.e., Holloman Air Force Base ("HAFB") Solar Facility) or voluntary program (i.e., Texas Community Solar program) to Texas. Instead, EPE directly assigns these costs to the "Other" jurisdiction in the JCOS so that none of these costs or related indirect costs are allocated to Texas customers' base rates.

Q. WHAT ARE THE SOLAR GENERATION FACILITIES THAT EPE DIRECTLY ASSIGNS TO TEXAS?

A. The following solar generation facilities and all related costs are directly assigned to the Texas jurisdiction:

- EPCC Valle Verde (TXSOL);
- Newman (TXSOL);
- Stanton Tower (TXSOL);
- Van Horn (TXSOL);
- Wrangler (TXSOL); and
- System Operations Center (TXSOL).

Q. WHAT METHOD IS USED FOR ALLOCATING JURISDICTIONAL DEMAND-RELATED COSTS OF PRODUCTION?

A. In this filing, EPE proposes to use the 4CP-A&E methodology for allocating jurisdictional demand related costs of non-peaking generation facilities and the 4CP methodology for allocating jurisdictional demand-related costs of peaking generation facilities.

EPE's system peaks during the summer months of June through September. These monthly peak demands are within 10 percent of the annual system peak demand most of the time, as shown in Exhibit AH-2. The production system is designed and built to meet both peak demand and EPE's energy requirements throughout the year. Therefore, EPE determined that the appropriate allocation for demand-related plant-in-service costs of production should be based on both a 4CP-A&E and a 4CP methodology.

Q. WHAT IS THE DIFFERENCE BETWEEN THE 4CP-A&E AND 4CP METHODOLOGIES?

A. The difference between the 4CP-A&E and the 4CP methodologies lies in how demand components are factored into each of the calculations. The 4CP-A&E methodology consists of both peak demand and annual average-demand components, while the 4CP methodology consists of just the peak-demand component. The specific calculations for each allocator are prepared under the supervision of EPE witness Novela.

Q. WHAT ALLOCATION METHOD WAS USED FOR ALLOCATING JURISDICTIONAL DEMAND-RELATED PLANT-IN-SERVICE COSTS OF PRODUCTION IN EPE'S PRIOR FILING?

A. In its 2017 rate case, EPE used the 4CP-A&E methodology for allocating jurisdictional demand-related plant-in-service costs of all generating facilities, identified as D1PROD in EPE's JCOS study.

Q. WHY HAS EPE DECIDED TO USE A 4CP ALLOCATION METHOD FOR ALLOCATING JURISDICTIONAL DEMAND-RELATED PLANT-IN-SERVICE COSTS OF PEAKING GENERATION FACILITIES?

A. EPE's generation facilities are a mix of non-peaking and peaking units. The peaking units were primarily designed to be ramped up and down as needed to meet load fluctuations, especially during peak summer hours. Unlike the other units, these facilities are not designed to run for extended periods of time. Therefore, the peaking units can be expected to be operating at high load during the times of EPE's system peak and for load following, but not necessarily during native system off-peak times (such as during the night). As described earlier in my testimony, EPE's system peaks during the four summer months of June through September. Please refer to the direct testimony of EPE witnesses David C. Hawkins and J Kyle Olson for descriptions of EPE's generation fleet's operation and performance.

Q. WHAT ARE THE GENERATION FACILITIES THAT EPE CONSIDERS AS PEAKING UNITS FOR COST-ALLOCATION PURPOSES?

A. EPE considers the following generation facilities as peaking units, and therefore, all costs related to them were allocated using the 4CP allocator, D2PROD:

- Montana Power Station Units 1 through 4,
- Rio Grande Generating Station Unit 9, and
- Copper Generating Station.

Q. WHAT ALLOCATOR IS USED FOR ALLOCATING JURISDICTIONAL PLANT-IN-SERVICE COSTS FOR TRANSMISSION?

A. EPE's transmission plant is treated by EPE as a single system that serves all jurisdictions regardless of geographic location. Because transmission is primarily built to meet the peak demand of EPE's service territory, and is not affected by energy needs, transmission plant-in-service costs are allocated on the 4CP methodology. The 4CP allocator D2TRAN reflects the need for this transmission during the four summer months of June through September, when EPE's system peak demands occur.

Q. HOW ARE DISTRIBUTION PLANT-IN-SERVICE COSTS JURISDICTIONALLY ALLOCATED?

A. Distribution plant-in-service costs in the JCOS study are directly assigned based on geographic location. The only exception is for any distribution plant costs related to the previously discussed solar facilities that are dedicated to a single customer.

Q. HOW ARE GENERAL PLANT-IN-SERVICE COSTS JURISDICTIONALLY ALLOCATED?

A. General plant-in-service costs are allocated using a labor allocation factor ("LABOR") which is derived from payroll costs included within the production, transmission, distribution and customer service functions.

Q. HOW DOES EPE DEVELOP THE LABOR ALLOCATION FACTOR?

A. The LABOR allocation factor is developed using a composite of EPE's functionalized operation and maintenance ("O&M") labor expenses, excluding A&G labor expenses. In other words, this dynamic allocator is derived from the payroll amounts (wages and salaries) found within the functional O&M accounts ranging from 500 through 903. These labor O&M expenses are allocated to each jurisdiction (then rate class and DEC component) based on their respective functional (production, transmission, distribution, or customer) allocators. The allocated result of all these labor O&M accounts for Texas (as a percentage of total company) in the JCOS is the allocation factor that is applied to costs with broad descriptions where a function is not specified.

Q. HOW ARE INTANGIBLE PLANT-IN-SERVICE COSTS JURISDICTIONALLY ALLOCATED?

A. Intangible plant-in-service costs are allocated using an allocation factor commensurate with the function that such intangible plant is associated with (i.e., production, transmission, distribution, and customer service functions). Otherwise, the LABOR allocator is used to allocate intangible plant costs where a function is not specified.

Q. HOW IS THE ACCUMULATED DEPRECIATION RELATED TO THE PLANT-IN-SERVICE COSTS JURISDICTIONALLY ALLOCATED?

A. Accumulated depreciation amounts are allocated using an allocation factor commensurate with the plant-in-service function that these amounts are associated with.

Q. HOW ARE WORKING CAPITAL AMOUNTS JURISDICTIONALLY ALLOCATED?

A. Working Cash is allocated using a dynamic allocator (OMXUNCOLL) based on the allocation on all O&M expenses except FERC Account 904 uncollectible expense. Materials and Supplies are allocated according to the function specified in the reg account description. Fuel inventory is allocated with E2ENERGY. Prepayments are allocated according to the function specified in the reg account description.

Q. IS THERE A SCHEDULE OR WORKPAPER THAT SHOWS HOW ALL RATE BASE AMOUNTS ARE JURISDICTIONALLY ALLOCATED?

A. Yes. Workpaper B-1.1 itemizes all the rate base amounts that are summarized in Schedule B-1.1 and presents the jurisdictional allocation of each amount along with the allocator that was applied to rate base amounts.

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

A. Demand-related production O&M expenses are allocated based on either the 4CP-A&E, 4CP, or 12CP allocator, identified in the JCOS model as D1PROD, D2PROD, and DPROD12, respectively. The D1PROD allocator is applied to O&M expenses of non-peaking generating facilities, and the D2PROD allocator is applied to O&M expenses of the peaking generating facilities. The DPROD12 allocator is applied to system control and dispatch expenses. Finally, EPE agreed in its last rate case to treat imputed capacity costs (non-reconcilable purchase power costs) as demand-related costs. EPE allocates imputed capacity costs with the D1PROD allocator.

Q. ARE THERE ANY ENERGY-RELATED PRODUCTION O&M EXPENSES?

A. Yes. Production O&M expenses that vary on the amount of energy produced are considered energy-related. There are two types of energy-related production O&M expenses. The first type is fuel and purchased power expenses which are recovered through EPE's Texas Fixed Fuel Factor ("TX FFF"). The second type of energy-related expenses are recovered in base rates.

Q. WHAT ARE THE DIFFERENT ENERGY ALLOCATORS AND HOW ARE THEY DEVELOPED?

A. EPE uses three different external allocators to allocate energy-related costs: E1ENERGY, E1FUEL, and E2ENERGY. E1ENERGY is used to allocate energy-related non-fuel production O&M expenses. E1FUEL is used to allocate fuel and purchased expenses. E2ENERGY is used to allocate costs that may be fuel-related or driven by a fuel-related activity but are not recovered through the TX FFF (i.e., fuel inventory or deferred taxes).

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Q. HOW ARE INCOME TAXES ALLOCATED TO EACH JURISDICTION?

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

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

A. Payroll and unemployment taxes are allocated to jurisdictions based on the LABOR allocation factor. Jurisdictional allocation of property taxes is consistent with how each plant-in-service functional grouping is allocated. Revenue-related taxes are directly assigned to the jurisdiction in which such taxes are assessed; therefore, the Texas jurisdiction is not allocated any New Mexico revenue-related taxes. Other taxes such as sales and use taxes are allocated based on the allocation of gross plant.

Q. IS THERE A SCHEDULE OR WORKPAPER THAT SHOWS HOW EXPENSES ARE JURISDICTIONALLY ALLOCATED?

A. Yes. Workpaper A-1 itemizes all the expenses and presents the jurisdictional allocation of each expense, along with the allocator that was applied for the allocation.

Q. BASED ON THE JURISDICTIONAL COST-OF-SERVICE STUDY YOU HAVE DISCUSSED, WHAT IS THE TEXAS REVENUE REQUIREMENT THAT EPE IS REQUESTING IN THIS CASE?

A. With reference to Schedule A-1 and Table AH-1 below, EPE has calculated a total revenue requirement for the Texas jurisdiction of $751.6 million. After adjusting that amount for fuel revenues and other operating revenues, the remaining $578.7 million base rate revenue requirement exceeds current annualized retail base revenue by $41.8 million (or 7.79 percent). The following table shows the results of the Texas jurisdictional cost of service:

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Table AH-1

Line	Description	Amount
1	Total Rate Base	$2,043,901,676
2	Weighted Average Cost of Capital ("WACC")	7.985%
3	Return on Rate Base	$163,210,454
4	Fuel and Purchased Power	$147,435,922
5	Operation and Maintenance (O&M)	$243,174,208
6	Depreciation & Amortization	$99,088,920
7	Decommissioning and Accretion	$111,981
8	Regulatory Debits and Credits	$2,986,404
9	Taxes Other Than Income	$68,511,555
10	Federal Income Taxes	$23,584,204
11	State Income Taxes	$3,528,578
12	**Total Cost of Service**	**$751,632,226**
13	Less: Other Operating Revenues	($26,921,992)
14	Less: Fuel Revenues and Sales for Resale	($146,004,473)
15	**Base Rate Revenue Requirement**	**$578,705,760**
16	Less: As Adjusted Base Revenues	($536,887,982)
17	**Base Rate Revenue Deficiency**	**$41,817,778**
18	Percent Increase	7.79%

Exhibit AH-3 presents an overall summary of the JCOS study.

EPE's As Adjusted Base Revenues of $536,887,982 (shown on line 16 of Table AH-1 above) reflect the known and measurable adjustments that are discussed in more detail in the direct testimony of EPE witness Carrasco.

Q. WHAT IS THE FIRM BASE REVENUE REQUIREMENT FOR THE TEXAS JURISDICTION THAT EPE IS REQUESTING IN THIS CASE?

A. As shown in Schedule A-1 (column f, line 1), the firm base revenues (the amount net of non-firm revenues) are $574,531,417. The firm base revenue increase is 7.85%

($41,817,778 base revenue deficiency from the as adjusted firm base revenues of $532,713,639). The firm base revenues calculated in the CCOS and DEC studies (at an equalized rate of return) will be discussed later and are provided to EPE witness Carrasco to develop EPE's proposed rates.

V. Class Cost-of-Service Study

Q. PLEASE DESCRIBE THE TEXAS RETAIL CLASS COST-OF-SERVICE STUDY MODEL.

A. The Texas retail class cost-of-service study model is the result of first producing a JCOS. In the class cost-of-service study, the Texas revenue requirements from the JCOS are assigned to each of the rate classes on a cost-causative basis. The CCOS provides the revenue and cost data for EPE's Texas service area that is required for preparation of the P schedules.

Q. WHAT IS REQUIRED TO PRODUCE A CCOS FOR THE TEXAS JURISDICTION?

A. Class responsibility for each cost is determined through direct assignments or allocations. Operating data are used to develop allocation factors by rate class that correspond to each cost classification factor (demand, energy, and customers). These allocation factors are calculated as percentages (i.e., Residential class as a percent of total Texas) which are then applied to specific revenue, expense, and rate-base items in the derivation of EPE's cost of service for Texas retail rate classes. This allocation is then summarized by the cost-of-service model and forms the basis for assigning items that are not specifically functionalized, such as accumulated deferred income taxes. If costs were incurred to benefit a clearly identifiable rate class, a direct assignment of that component is made (e.g., street lighting).

Q. WHAT ARE DIRECTLY ASSIGNED COSTS?

A. Directly assigned costs consist of those costs that are incurred specifically for certain rate classes. For example, EPE incurs costs for operating and maintaining street lights (such as replacing burnt lamps); therefore, these costs are directly assigned to the Street-lighting rate class in the CCOS.

Q. WHAT TYPES OF ALLOCATORS ARE USED IN THE CLASS COST-OF-SERVICE STUDY?

A. Similar to the JCOS, the RMS model utilizes two general types of allocators: imported or "external" allocators, and dynamic or "internal" allocators for the CCOS.

Q. IS EPE PROPOSING TO ADD OR REMOVE ANY RATE CLASSES IN THIS PROCEEDING?

A. No.

Q. WHAT METHOD IS USED TO ASSIGN THE DEMAND-RELATED COSTS OF THE PRODUCTION PLANT-IN-SERVICE TO EACH RATE CLASS?

A. As explained in the JCOS section, in this filing, EPE proposes to use the 4CP-A&E methodology (D1PROD) for assigning demand-related costs of non-peaking generation facilities and the 4CP methodology (D2PROD) for assigning demand-related costs of peaking generation facilities. The CCOS uses these allocators to assign demand-related cost to the rate classes.

Q. HOW ARE THE DEMAND-RELATED COSTS OF TRANSMISSION PLANT-IN-SERVICE ASSIGNED TO EACH RATE CLASS?

A. Consistent with the JCOS study, transmission plant is assigned to each rate class using the 4CP allocator D2TRAN.

Q. HOW IS THE DEMAND-RELATED COST OF DISTRIBUTION PLANT-IN-SERVICE ASSIGNED TO EACH RATE CLASS?

A. EPE uses the Maximum Class Demand ("MCD") to assign substation and primary distribution feeder system costs and Non-Coincident Peak Demand ("NCP") to assign secondary voltage distribution feeders and line transformer costs.

Q. HOW ARE MCD AND NCP DEVELOPED, AND WHAT DO THEY REPRESENT?

A. EPE witness Novela develops the MCD and NCP. In general, MCD represents the diversified loads of a rate class at the system peak; NCP represents the summation of the maximum loads of each customer within a rate class.

Q. WHY DOES EPE USE BOTH THE MCD AND NCP ALLOCATORS FOR DISTRIBUTION PLANT?

A. These distribution plant allocators are based on the level of voltage service received. The cost causation for the distribution system differs for each voltage level; therefore, EPE developed allocation factors for each of these levels to reflect the type of loads that most significantly influence the costs at that level. The MCD is appropriate for the primary voltage plant because the primary distribution system serves all distribution level customers. The NCP Demand allocator is a measurement of maximum attainable peak demand by each rate class, independent of the class or system peak. This method allocates costs to serve customers based on their diversity at the more localized secondary distribution system.

Q. HOW ARE DISTRIBUTION PLANT-IN-SERVICE ACCOUNTS RELATED TO SUBSTATIONS (NOS. 360 THROUGH 362) ASSIGNED TO EACH RATE CLASS?

A. Distribution Plant Account No. 360 - Land and Land Rights, Account No. 361 - Structures and Improvements, and Account No. 362 - Station Equipment costs are assigned based on the MCD allocator described previously. The MCD allocator (D3DIST, D4DIST, D7DIST, or D9DIST) reflects the responsibility and costs to the customers served downstream from substations.

Q. HOW ARE DISTRIBUTION PLANT-IN-SERVICE ACCOUNT NOS. 364 THROUGH 368 ASSIGNED TO RATE CLASSES?

A. Distribution Plant Account No. 364 - Poles, Account No. 365 - Overhead Conductors, Account No. 366 - Underground Conductors and Account No. 367 - Underground Conduits and, Account No. 368 - Line Transformers costs are separated based on the distribution voltage level served, either primary or secondary. The primary voltage level costs are assigned to rate classes using the MCD allocator. The secondary voltage level costs are assigned based on the NCP allocator (D5DIST, D6DIST, D8DIST, or D10DIST).

Q. HOW IS THE CUSTOMER-RELATED COST OF DISTRIBUTION PLANT-IN-SERVICE ASSIGNED TO EACH RATE CLASS?

A. EPE also assigns costs for services on a service drop investment allocator ("SDI") and costs for meters based on a weighted meter cost allocator ("METER"). Lighting-related facilities are directly assigned to the associated rate class such as street lighting or private area lighting.

Q. HOW DOES EPE ASSIGN COSTS FOR ACCOUNT NO. 369 – SERVICES TO EACH RATE CLASS?

A. Account No. 369 – Services, e.g., costs of service drops from the distribution system to serve customers, is assigned to rate classes based on the SDI allocator. This method creates an allocator based on the number of services per rate class weighted by the typical cost to provide a service drop to that rate class.

Q. WHAT ASSIGNMENT METHOD DOES EPE USE FOR ACCOUNT NO. 370 - METERS?

A. EPE uses the METER allocator to better reflect the cost causation based on the differing meter costs among the classes. Therefore, the count of meters for each rate class is weighted by the typical cost of a meter. This procedure assigns meter costs to each class proportional to the class and level of service directly impacted by these costs.

For example, customer classes with larger per-customer loads typically use a more technologically advanced meter (e.g., Interval Data Recorder meter). These meters are more expensive than a simple residential energy measuring meter, thus a greater weight is applied to such meters.

Q. HOW ARE GENERAL PLANT-IN-SERVICE COSTS ASSIGNED TO EACH RATE CLASS?

A. General plant-in-service costs are assigned to rate classes based on the LABOR allocator.

Q. HOW ARE INTANGIBLE PLANT-IN-SERVICE COSTS ASSIGNED TO RATE

CLASSES?

A. Intangible plant-in-service costs are allocated to rate classes using an allocation factor commensurate with the function that such intangible plant is associated with (i.e., production, transmission, distribution and customer service functions).

Q. HOW IS THE ACCUMULATED DEPRECIATION RELATED TO THE PLANT-IN-SERVICE COSTS ASSIGNED?

A. Accumulated depreciation amounts are assigned to each rate class using an allocation factor commensurate with the plant account that these amounts are associated with.

Q. HOW ARE WORKING CAPITAL AMOUNTS ASSIGNED TO EACH RATE CLASS?

A. Consistent with the allocation in the JCOS, Working Cash is allocated using the dynamic allocator OMXUNCOLL. Materials and Supplies are allocated according to the function specified in the reg account description. Fuel inventory is allocated with E2ENERGY. Prepayments are allocated according to the function specified in the reg account description.

Q. IS THERE A SCHEDULE THAT SHOWS HOW ALL RATE-BASE AMOUNTS ARE ASSIGNED TO EACH RATE CLASS?

A. Yes. Schedule P-3 itemizes all the rate-base costs and presents the rate class assignment of each cost, along with the allocator that was applied for the assignment.

Q. HOW ARE POWER PRODUCTION EXPENSES ASSIGNED TO EACH RATE CLASS?

A. Reconcilable fuel and purchased power related expenses are allocated on the energy allocator E1FUEL. Non-fuel energy-related power production expenses are allocated using E1ENERGY. The remaining demand-related power production expenses are allocated based on either the 4CP-A&E allocator (D1PROD); 4CP allocator (D2PROD); or, 12CP allocator (DPROD12).

Q. HOW ARE TRANSMISSION O&M EXPENSES ASSIGNED TO EACH RATE

CLASS?

A. Consistent with the JCOS, FERC Account 561 – Load Dispatching expenses are allocated using a 12CP allocator (DTRAN12). All other transmission O&M expenses are assigned to each rate class with the D2TRAN allocator.

Q. HOW ARE DISTRIBUTION O&M EXPENSES ASSIGNED TO EACH RATE CLASS?

A. Generally, the Distribution O&M costs are assigned to each rate class based on the related distribution plant account allocation. There are two exceptions where the expenses are not based on plant accounts. First, Account No. 580 - Supervision and Engineering is allocated on dynamic allocator EXP_5817 (based on Accounts 581 through 587) to mirror the allocation of the other distribution expenses in their section. Account No. 588 - Misc. Distribution Expenses is also allocated using the dynamic allocator EXP_5817. The other exception is Account No. 589 - Rents, which is allocated based on total distribution plant (DISTPLT).

Q. HOW ARE CUSTOMER ACCOUNTS (ACCOUNT NOS. 901 – 905) AND CUSTOMER SERVICE & INFORMATION O&M (ACCOUNT NOS. 906 – 910) EXPENSES ASSIGNED TO EACH RATE CLASS?

A. Account No. 901 - Supervision is assigned to each rate class using a dynamic allocator based on the expenses contained in the other accounts of the account grouping. Account No. 902 - Meter Reading Expenses are based on a meter-related allocation factor, while Account Nos. 903 - Customer Records and Collections, 905 - Miscellaneous Customer Expenses, and 909 - Informational and Instructional Advertising Expenses are assigned to rate classes using a customer-count allocation factor. Major account representative labor expenses in FERC Account 903 are allocated based on the number of customers in nonresidential rate classes.

As previously discussed, Account No. 904 - Uncollectible Accounts expenses are assigned based on the firm base and fuel revenues of each rate class, except for those rate classes that are not subject to account write-offs such as governmental customers or C&I Large customers.

Q. HOW ARE ADMINISTRATIVE AND GENERAL EXPENSES ASSIGNED TO EACH RATE CLASS?

A. Most A&G expenses are assigned to rate classes using the LABOR allocator or a labor-related allocation factor derived from the labor expenses contained in the accounts of the applicable functional account grouping. A&G expenses related to a specific function (e.g., production, transmission, distribution) are assigned an allocator based on the account description.

Q. HOW ARE THE DEPRECIATION AND AMORTIZATION EXPENSES ASSIGNED TO EACH RATE CLASS?

A. EPE assigns to each rate class depreciation and amortization expenses by function consistent with the assignment of the respective plant-in-service and accumulated depreciation accounts.

Q. HOW ARE REGULATORY DEBITS AND CREDITS ASSIGNED TO EACH RATE CLASS?

A. Regulatory debits and credits are allocated differently depending on the function of the specific debits and credits. The amount associated with the COVID adjustment is allocated to each rate class with the LABOR allocator and the amount associated with Four Corners decommissioning is allocated with D1PROD.

Q. HOW ARE TAXES OTHER THAN INCOME TAXES ASSIGNED TO EACH RATE CLASS?

A. Similar to the JCOS, payroll and unemployment taxes are assigned to rate classes based on the LABOR allocation factor. Assignment of property taxes to each rate class is consistent with how each plant-in-service functional grouping is allocated. Revenue-related taxes are based on a dynamic revenue allocation factor. Other taxes such as sales and use tax are allocated with a gross plant allocator, GROSSPLT.

Q. HOW ARE INCOME TAXES ALLOCATED TO EACH RATE CLASS?

A. Similar to the JCOS, deferred federal and state income taxes are allocated using a dynamic allocator such as NETPLT unless a specific cost item is identified (such as deferred taxes related to energy). Current federal and state income taxes are calculated at the rate class level in the model in the same way the jurisdictional and the total company current income taxes are calculated.

Q. IS THERE A SCHEDULE THAT SHOWS HOW EXPENSES ARE ASSIGNED TO RATE CLASSES?

A. Yes. Schedule P-2 itemizes all the expenses and presents the assignment of each expense to each rate class and provides the allocator that was applied for the assignment.

Q. HOW DOES THE CCOS ALLOCATE THE NON-FIRM, FUEL, AND OTHER OPERATING REVENUES TO EACH RATE CLASS?

A. Unlike the previous rate case where EPE used the RATEBASE allocator, non-firm revenue is allocated to rate classes using the D2PROD allocator in this case. The reason this change makes sense is because non-firm revenues from interruptible customers are used in order to reduce peak demand. As previously discussed, the D2PROD allocator is used to allocate peaking-generation units.

Fuel revenues are adjusted to match the reconcilable fuel and purchased power expenses of each rate class, net of off-system sales. The reconcilable fuel and purchased power expenses and off-system sales fuel costs are allocated to each rate class with the E1FUEL allocator.

Other Operating Revenues are allocated to each rate class with various allocators depending on the function specified. For example, Miscellaneous Service Revenues are allocated with the distribution or customer-related allocators and Forfeited discounts are allocated similar to uncollectible expense.

EPE's revenues (including other operating revenues) are discussed in the Direct Testimony of EPE witness Carrasco. These revenues (non-firm, fuel-related, and other operating revenues) are credited against the Total Cost of Service to arrive at the firm Base Rate Revenue Requirement of each rate class.

Q. HOW IS THE CLASS COST-OF-SERVICE STUDY PRESENTED IN THE FILING?

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

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

A. The summarized result of the CCOS study are presented in Exhibit AH-4. In addition, Table AH-2 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) and do not represent the proposed distribution of revenues for rate design purposes. The proposed allocation of revenue requirements and rate design is discussed and presented in the testimony of EPE witness Carrasco.

Table AH-2

Rate	Description	Firm Base Revenue Deficiency @ Equalized Rate of Return*	Percent Increase Required
01	Residential Service	$52,607,044	19.22%
02	Small General Service	(3,181,502)	-9.55%
07	Outdoor Recreational Lighting	153,617	33.18%
08	Government Street Lighting	(967,831)	-23.92%
09	Traffic Signals	3,416	3.59%
11TOU	Municipal Pumping TOU	95,157	0.94%
15	Electrolytic Refining Service	407,243	22.25%
WH	Water Heating Service	335,205	70.63%
22	Irrigation Service	135,518	32.01%
24	General Service	(10,767,792)	-8.61%
25	Large Power Service	1,321,031	3.67%
26	Petroleum Refinery Service	1,976,474	18.03%
28	Area Lighting Service	(289,540)	-9.87%
30	Electric Furnace Rate	314,558	26.39%
31	Military Reservation Service	1,766,040	13.57%
34	Cotton Gin Service	45,212	34.00%
41	City and County Service	(2,136,072)	-11.17%
Total*		$41,817,778	7.85%

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

Q. HAVE YOU SEEN ANY SIGNIFICANT CHANGES IN COSTS ALLOCATED TO RATE CLASSES COMPARED TO PRIOR RATE CASES?

A. Yes. The CCOS study resulted in some significant reallocation of costs between rate classes that were unlike EPE's CCOS studies from previous rate cases. The shift in allocation between rate classes is driven by the allocation factors used in this case. As discussed by EPE witness Novela in his direct testimony, the allocation factors for the test year were impacted by the COVID-19 pandemic. Capping adjustments to account for the abnormalities witnessed in 2020 are addressed in the direct testimonies of EPE witnesses Carrasco and Schichtl.

VI. Demand, Energy, and Customer Components Study

Q. PLEASE DESCRIBE THE DEMAND, ENERGY, AND CUSTOMER COMPONENTS STUDY.

A. The Demand, Energy, and Customer Components Study ("DEC Study") is the final step in the process after the jurisdictional and class cost-of-service studies. The DEC Study allocates costs by rate class to each of the DEC components. These results are essential in developing rates and are provided to EPE witness Carrasco for developing proposed rates.

Q. HOW DO THE FUNCTIONALIZED COSTS IDENTIFIED IN PREVIOUS STEPS RELATE TO THE COSTS PRESENTED IN THE DEC STUDY?

A. The functionalized costs of Production, Transmission, Distribution, and Customer are classified into Demand, Energy, and Customer components in the DEC Study as shown in Table AH-3.

Table AH-3

Cost Functions	Cost Classifications
Production	Demand Related Energy Related
Transmission	Demand Related
Distribution	Demand Related Customer Related
Customer	Customer Related

Q. WHAT ARE THE SPECIFIC COMPONENTS PRESENTED IN THE DEC STUDY THAT MAKE UP THE DEMAND, ENERGY, AND CUSTOMER CLASSIFICATIONS?

A. The components are shown in Table AH-4 below.

Table AH-4

Demand	Energy	Customer
Demand - Production	Energy - Other	Customer - Other
Demand - Transmission	Energy - Fuel	Customer - Deposits
Demand - Distribution		Customer - 369 Services
- Dem Dist - Load Dispatching		Customer - 370 Meters
- Dem Dist - Poles Towers Fixtures - Primary		Customer - 371 Install on Customer Premise
- Dem Dist - Poles Towers Fixtures - Secondary		Customer - 373 Street Lighting
- Dem Dist - Overhead Lines - Primary		Customer - 902 Meter Reading
- Dem Dist - Overhead Lines - Secondary		Customer - 903 Customer Rec & Collections
- Dem Dist - Underground Lines - Primary		
- Dem Dist - Underground Lines - Secondary		
- Dem Dist - Line Transformers - Primary		
- Dem Dist - Line Transformers - Secondary		

Q. HOW IS PRODUCTION PLANT-IN-SERVICE CLASSIFIED?

A. Production plant is classified as demand related. Therefore, all production plant accounts fall under the Demand Production component.

Q. HOW IS TRANSMISSION PLANT-IN-SERVICE CLASSIFIED?

A. Transmission plant is classified as demand related, and all transmission plant accounts fall under the Demand Transmission component.

Q. HOW IS DISTRIBUTION PLANT-IN-SERVICE CLASSIFIED?

A. Distribution investments serve customer demands as well as providing a basic investment uniformly common to all customers. For this reason, Distribution plant will have both a Demand component and a Customer component as seen on Table AH-3.

Distribution Plant Account No. 360 - Land and Land Rights, Account No. 361 - Structures and Improvements, and Account No. 362 - Station Equipment are allocated to the Distribution-Load Dispatching component of Demand. Distribution Plant Account

No. 364 - Poles is assigned to the Distribution-Poles, Towers, and Fixtures ("PTF") component of Demand. Account No. 365 - Overhead Conductors is assigned to the Distribution-Overhead component of Demand. Account No. 366 - Underground Conductors and Account No. 367 - Underground Conduits are assigned to the Distribution-Underground component of Demand. All of these are separated based on the distribution voltage level served, either primary or secondary. Account No. 368 - Line Transformers is also separated based on the distribution voltage level served, either primary or secondary. It is assigned to the Distribution-Transformer component of Demand.

Account No. 369 - Services is classified as a Customer-related cost and falls under the Customer - 369 Services component under Customer. Account No. 370 - Meters is classified as a Customer-related cost and it falls under the Customer No. 370 - Meters component under Customer.

Q. HOW ARE GENERAL PLANT-IN-SERVICE COSTS ALLOCATED TO DEC COMPONENTS?

A. Similar to how general plant costs in the CCOS study are allocated on the LABOR allocation factor (which functionalizes the costs based on O&M labor), general plant costs in the DEC Study are spread among the DEC components the same way.

Q. HOW IS WORKING CAPITAL ALLOCATED IN THE DEC STUDY?

A. Consistent with the CCOS study, working cash is allocated using an O&M allocator excluding uncollectible expense. Fuel inventory is allocated with the E2ENERGY allocator. Prepayments and Materials and Supplies are allocated with different allocators based on the functional account descriptions.

Q. IS THERE A SCHEDULE THAT SHOWS HOW ALL RATE-BASE AMOUNTS ARE ASSIGNED TO DEMAND, ENERGY, AND CUSTOMER?

A. Yes. Schedule P-5 itemizes all the rate base costs and presents them by the Demand, Energy, and Customer classifications, along with the allocator that was applied for the assignment.