STATE OF TEXAS

BEFORE THE PUBLIC UTILITY COMMISSION

In the Matter of the Application of El	**)**	
Paso Electric Company to Change	**)**	**Docket No. 44941**
Rates	**)**	
__________________________________	**)**	

DIRECT TESTIMONY OF

PAUL CHERNICK

ON BEHALF OF

THE ENERGY FREEDOM COALITION OF AMERICA

Resource Insight, Inc.

DECEMBER 11, 2015

TABLE OF CONTENTS

TABLE OF EXHIBITS

I. Identification and Qualifications

Q: Please state your name, occupation and business address.

A: I am Paul L. Chernick. I am the president of Resource Insight, Incorporated, located at 5 Water Street, Arlington, Massachusetts.

Q: Summarize your professional education and experience.

A: In June 1974, I received a Bachelor of Science degree from the Massachusetts Institute of Technology from the Civil Engineering Department. In February 1978 I received a Master of Science degree in Technology and Policy from the Massachusetts Institute of Technology.

I was a utility analyst for the Massachusetts Attorney General for more than three years, and was involved in numerous aspects of utility rate design, costing, load forecasting, and the evaluation of power supply options. Since 1981, I have worked as a consultant in utility regulation and planning. From 1981 to 1986 worked as a research associate at Analysis and Inference. In 1986, I founded and became president of PLC, Incorporated, which was renamed Resource Insight, Incorporated in 1990. In these capacities, I have advised a variety of clients on utility matters.

My work has considered, among other things, the cost-effectiveness of prospective new generation plants and transmission lines, retrospective review of generation-planning decisions, ratemaking for plants under construction, ratemaking for excess and/or uneconomical investments entering service, conservation program design, cost recovery for utility efficiency programs, the valuation of environmental externalities from energy production and use, allocation of costs of service between rate classes and jurisdictions, design of retail and wholesale rates, and performance-based ratemaking and cost recovery in restructured gas and electric industries. My professional qualifications are further described in Exhibit PLC-1.

Q: Have you testified previously in utility proceedings?

A: Yes. I have testified as an expert nearly three hundred times on utility issues before various regulatory, legislative, and judicial bodies, including utility regulators in thirty-three states, six Canadian provinces, and two U.S. Federal agencies. A large number of those cases involved power supply planning; evaluation of potential resources, including purchased-power agreements (PPAs); restructuring of electric markets; and power procurement for restructured utilities. My previous testimony before the Public Utility Commission of Texas is listed in Exhibit PLC-2.

II. Introduction

Q: On whose behalf are you testifying in this rate case proceeding?

A: I am testifying on the behalf of the Energy Freedom Coalition of America.

Q: What is the purpose of your testimony?

A: I review several aspects of the rate-design proposals by El Paso Electric (EPE) in this proceeding, along with related cost-allocation issues, and assess how these proposals affect residential customers with distributed generation (DG), including solar photovoltaic panels, behind their meters. My testimony focuses on the following EPE proposals:

- Split the partial requirements customers, or residential distributed-generation customers, off from the current standard residential Rate No. 01 (available as a flat two-part rate or a time-of-use alternative), and require these customers to take service on the new Rate No. 03, a three-part rate with a demand charge and TOU option, available to distributed generation customers only.

- Allocate primary distribution costs to DG customers, not on the basis of contribution to the residential maximum class demand (MCD), but based on their load on a different day and at a later hour when the loads of the distributed-generation customers are higher.
- Allocate secondary distribution costs to DG customers on the basis of the sum of their customer-specific annual peaks (which EPE calls non-coincident peak, or NCP).
- Recover all of the distribution costs allocated to DG customers through monthly demand charges, rather than the current method of collecting distribution costs through energy charges. The demand charges will be computed based on a DG customer's 30-minute maximum load over the course of the month, regardless of whether the maximum demand is coincident with any relevant peak.

Q: Please describe EPE's proposals for setting rates for residential customers with distributed generation.

A. El Paso Electric proposes a "Partial Requirements Service rate" that will apply to "new and existing residential customers with renewable generation installed behind their meter." (Schichtl Direct, p. 30.) As described by EPE witness James Schichtl, EPE proposes to charge Partial Requirements residential customers "a monthly customer charge, a flat demand charge based on metered monthly demand, and tiered seasonal energy charges similar to the energy charge structure proposed for Residential customers." Schichtl Direct, p. 33. El Paso Electric proposes that the average distributed-generation rate be increased by twice as much as residential Rate 01, 23.56% compared to 11.78%.

Q: What do you conclude from your review of EPE's proposal?

A: I conclude the following:

- EPE's proposal to treat residential DG customers as a separate rate class 3, rather than as part of the Rate No. 1 residential class, should be rejected. In general, a utility should be indifferent about what type of technology a customer has chosen to use in their home. this is especially true where the customer's efforts provide benefits to the system, reducing costs for all ratepayers.
- The residential class is diverse, and the load characteristics of DG customers fall within that diversity.
- The EPE cost-of-service study (COSS) overstates the cost to serve DG customers in the following ways:
    - EPE's proposed allocation of primary distribution ignores the high diversity of distributed-generation customer loads within the total residential class.
    - Customer NCPs are largely irrelevant to cost causation, especially for distributed-generation customers scattered among full-service residential customers.
    - Little or none of EPE's distribution costs are caused by the monthly customer maximum loads; energy charges, especially TOU energy charges, would better reflect the loads driving distribution costs.
    - Similarly, little or none of EPE's generation and transmission costs are caused by the monthly customer maximum loads.

This inflated estimate of the cost of serving DG customers in no way supports the treatment DG customers as a rate class separate from the residential rate class.

- Even if EPE were to demonstrate a need for increased collection of DG distribution-related costs, demand charges are confusing to customers and difficult to manage.

- EPE overstates the fixed costs associated with DG service and as such overstates the increase in the fixed charge.
- Last, the excess energy delivered from solar customers to EPE's system over the course of any given month is more valuable than the price that EPE proposes to pay. EPE should fairly compensate DG customers for the benefits that they provide to all EPE ratepayers.

Q: What are your recommendations?

A: My primary recommendation is that the Commission reject EPE's proposal to create a DG-only tariff. DG customers are unexceptional residential customers, and should continue to take service on the current residential Rate No. 1. I further recommend that the Commission should take the following steps with respect to EPE's COSS allocation and rate design:

- Allocate primary distribution costs to the residential class using a single residential MCD, rather than the sum of two MCDs at different times in different months.
- Allocate secondary distribution costs within the residential class in proportion to energy, until EPE develops data on the subclass contributions to loads at the times that transformers and secondary lines are heavily loaded.
- Reject EPE's proposal to extend to DG customers a three-part rate design, including demand charges. As noted above, demand charges are inefficient, ineffective, confusing to customers and unjustified.
- Reject EPE's proposed fixed charge increase, as it overstates the fixed costs associated with DG service, namely the cost of the DG meter.

- Increase the payment rate for net monthly deliveries by DG customers to the distribution system to the approximately 8.4¢/kWh price of the 3 MW Montana community solar facility.

III. Overview of EPE's Proposal

Q: Please describe EPE's residential renewable distributed generation proposals.

A. EPE requests that the Commission approve a "Partial Requirements Service rate" that will apply to "new and existing residential customers with renewable generation installed behind their meter." Schichtl Direct, p. 30. As described by EPE witness Mr. Schichtl, EPE proposes to charge Partial Requirements residential customers "a monthly customer charge, a flat demand charge based on metered monthly demand, and tiered seasonal energy charges similar to the energy charge structure proposed for Residential customers." Schichtl Direct, p. 33.

Q: Describe the effects that EPE's proposal will have on residential customers with installed renewable distributed generation.

A. EPE's proposal would place residential customers with renewable distributed generation installed behind the meter such as rooftop solar panels in Rate No. 03 – Partial Requirements. Placement in this class would increase these customers' rates by 23.56% compared to 11.78% for other residential customers if its rate Application is approved. Schichtl Direct, p. 7. The projected bill impact to Partial Requirements customers is shown on Attachment JS-5 to Mr. Schichtl's Direct Testimony and demonstrates an impact of a bill increase up to 200% or $600 for residential customers with installed renewable distributed generation.

Q: Should EPE's proposal to establish a Partial Requirements class be adopted by the Commission?

A. No. EPE has not demonstrated any justification for imposing a greater rate increase on residential customers with renewable distributed generation.

Q: Why not?

A: EPE's proposed creation of a separate rate class for residential renewable distributed generation customers is based on a single distinguishing criterion – their interconnection of renewable distributed generation. This distinction is not sufficient to justify separating these customers from other residential customers given the significant diversity of residential power usage characteristics of EPE's residential customers. Further, the small number of residential customers with renewable distributed generation in EPE's service territory does not justify removal of those customers into a separate rate class. In fact, EPE's proposal results in residential renewable distributed generation customers being assigned proportionately higher generation, transmission, and distribution costs than can be justified by EPE's cost analysis, which is severely limited with respect to what costs of service are actually incurred for residential renewable distributed generation customers. Most importantly, EPE's proposal does not recognize or give economic credit for the benefits provided by residential customers who install renewable distributed generation, including production capacity benefits, environmental benefits, peak load reduction, and the public policy benefits that the Texas Legislature and PUC have recognized in establishing policies to promote renewable distributed generation. EPE's proposal would actually have the effect of discouraging residential customers from installing solar panels and other forms of renewable distributed generation, which would be contrary to sound public policy.

IV. Load Characteristics of Residential Customers with and without DG

Q: What are the load characteristics of the customers in EPE's residential rate class?

A: El Paso Electric's residential rate class (Rate 01) includes electric service for single-family residences, individually-metered apartments, and other non-commercial uses located on the same property, where those are served through an extension from the main residence.

Q: Do customers in EPE's residential rate class have a narrow range of load characteristics?

A: No. EPE divides its residential customers into five strata of monthly energy use, which it describes as follows (Exhibit GN-7 at 2):

- Stratum 1: 0–300 kWh
- Stratum 2: 301–500 kWh
- Stratum 3: 501–800 kWh
- Stratum 4: 801–1,400 kWh
- Stratum 5: 1,401–13,500 kWh

The residential load sample (OPUC 6-004) shows broader and overlapping strata ranges:

- Stratum 1: up to 327 kWh
- Stratum 2: 258–547 kWh
- Stratum 3: 221–859 kWh
- Stratum 4: 554–2,956 kWh
- Stratum 5: 1,192–7,901 kWh

For the residential load-research sample, per-customer load ranges from

- zero to 28.6 kW at the four summer monthly peaks,
- 0.04 kW to 13.5 kW at the winter peak,
- zero to 45 kW at the time of the residential class peak,
- 0.4 to 18.6 kW at the customer's non-coincident summer peak, and
- 0.4 to 37.9 kW at the customer's non-coincident winter peak.

Residential customer load factors also vary widely:

- 10% to 28,000% at the summer system peak,
- 21% to 7,000% at the winter peak,
- 7% to 700% at the time of the residential class peak, and

- 29% up to 100% at the customer's non-coincident summer peak.[1]

Q: What factual justification does EPE provide for its Partial Requirements class proposals?

A: Mr. Schichtl testifies that residential customers with distributed generation installed behind the meter "display a different usage profile than full requirements customers." Schichtl Direct at 31. Mr. Schichtl further states that "the different usage profile of partial requirements customers from other residential customers results in different costs being imposed on EPE's system" and "the residential rate does not accurately reflect the costs partial requirements customers impose, or do not impose, on EPE's system." *Id.* at 32-33.

Q: How do the residential customers with distributed generation compare to the other residential customers in the load-research sample?

A: According to EPE, the average customer with distributed generation uses 1,115 kWh monthly, falling within Stratum 4 (Exhibit GN-7 at 2). Because these customers generate some of their own electricity, EPE supplies them an average of 770 kWh monthly (Exhibit GN-7 at 4).

The distributed-generation customers in the load-research sample actually show ranges of average energy delivery per customer from 212 to 2,080 kWh per month, distributing them across Strata 1 through 5. Their peak loads range from:

- zero to 8.7 kW at the four summer monthly peaks,
- zero to 5.8 kW at the winter peak,
- zero to 7.9 kW at the time of the residential class peak,

[1] El Paso Electric's data contain some reporting errors, such as customer NCPs that are lower than the customer's reported contribution to the class diversified demand, which is impossible. I capped the MCD load factor at 100% for this analysis

- 3.1 to 13.2 kW at the customer's non-coincident summer peak (with one value at 36.6 kW, which seems to be a data error), and
- 2.8 to 11.2 kW at the customer's non-coincident winter peak (again, with one suspect outlier).[2]

These loads are not atypical for residential customers without distributed generation.

The load factors for the residential customer sample with distributed generation also fall within the range for other residential customers:

- 16% to 6,400% at the summer system peak,
- 23% to 6,500% at the winter peak,
- 7% to 6,400% at the time of the residential class peak, and
- 3% up to 35% at the customer's non-coincident summer peak.

The high end of the load factor coincident with residential class peak is higher for the distributed-generation sample than the non-DG sample, but only 6% of the DG sample exceeds the residential sample range. The low end of the non-coincident load factor is lower for distributed-generation than non-DG customers, but 69% of the customers with distributed generation have NCP load factors within the sampled residential range.

Q: Do the load characteristics of residential customers with installed renewable distributed generation justify their separation into a "Partial Requirements" rate class?

A: No. Residential customers with DG are well within the range of load-characteristic diversity in EPE's residential rate class. EPE's attempt to move residential

[2] El Paso Electric's NCP data appear to have many errors, and any computations based on them should be taken with a large grain of salt. Fortunately, customer NCPs do not actually drive much in the way of costs.

customers with DG into a separate class cannot be justified the energy use, peak demands, or load factors of those customers.

Q: Does EPE specify in what manner the usage profiles of customers with distributed generation differ from those of other residential customers that would justify a separate rate class?

A: No. Mr. Schichtl testifies that residential customers with distributed generation show a "predictable decrease in energy delivered by EPE…as well as lower demand at the time of the system peak." Schichtl Direct at 32. But then Mr. Schichtl asserts that "peak demand for partial requirements customers is not markedly different than that for similar size full requirements customers, because their peak occurs even later than system peak when DG production is significantly reduced." *Id.* This assertion is repeated by Mr. Novela. Exhibit GN-7 at 2-4. In making this assertion, El Paso Electric appears to be focusing on the customers' non-coincident peaks, which have little or no effect on cost causation, as I discuss elsewhere.[3]

By any reasonable measure, the residential customers with distributed generation are paying their fair share of the residential costs, and there is no reason to shift them to another class.

Q: Is it appropriate for a utility to require customers to take service under either of the Rate No. 03 options?

A: No. EPE's proposal for a separate DG rate class is unjustified given the diversity of the residential class. In addition, it is unreasonable for a utility to reach behind the meter to select certain customers for less favorable rate treatment, based on their use of a particular technology in their home. El Paso Electric's proposal will require all DG customers to take service under a tariff would tend to increase their bills,

[3] Even EPE proposes to allocate only secondary lines and line transformers on NCP.

based on the manner in which they have chosen to reduce their usage of electricity. EPE has not proposed to do anything similar for customers who purchase energy-efficient appliances, use gas instead of electricity for heating, or have equipment with high energy use and unusual load profiles, such as swimming pools and electric pottery kilns.

V. Load Shapes of Distributed Generation and DG Customers

Q: Recognizing that solar photovoltaic installations dominate the current and expected residential distributed-generation load on EPE's system, please describe the pattern of solar generation over time.

A: Table 1 compares the pattern of EPE's monthly energy loads for 2006 through 2014, along with EPE's estimate of monthly solar output, which I derived as the difference between household and delivered load for the distributed-generation customers in EPE's response to OPUC 1-012.[4] As the table shows, the monthly pattern of solar output closely matches EPE's energy requirements.

Table 1: Monthly EPE Energy Loads and Solar Output

	El Paso Electric Energy Load as % Annual										**Solar**
Month	2006	2007	2008	2009	2010	2011	2012	2013	2014	Average	
Jan	7%	8%	8%	7%	7%	7%	7%	8%	7%	7.6%	5.3%
Feb	7%	7%	7%	7%	7%	7%	7%	7%	6%	6.7%	5.4%
March	7%	7%	7%	7%	7%	7%	7%	7%	7%	7.2%	6.9%
April	8%	7%	7%	7%	7%	7%	8%	7%	7%	7.4%	7.6%
May	9%	8%	9%	9%	8%	8%	9%	9%	9%	8.6%	10.3%
June	10%	9%	10%	9%	10%	10%	10%	10%	11%	10.0%	14.3%
July	10%	10%	10%	11%	10%	11%	10%	10%	11%	10.4%	13.2%
August	10%	11%	10%	11%	11%	11%	11%	11%	10%	10.5%	10.4%
Sept	8%	9%	9%	9%	10%	9%	9%	9%	9%	9.0%	8.3%
Oct	8%	8%	8%	8%	8%	8%	8%	8%	8%	7.9%	7.2%
Nov	7%	7%	7%	7%	7%	7%	7%	7%	7%	7.1%	5.7%
Dec	8%	8%	7%	8%	7%	8%	7%	8%	8%	7.7%	5.3%

[4] Data has been normalized using the average annual monthly load or output.

The monthly pattern of solar output closely matches EPE's energy requirements. Figure 1 compares the average daily load and solar output, as a percentage of the annual average. Solar provides a more than proportionate share of its output in the high-load months of June to August, and less in the low-load months of October to February. Adding solar to EPE's system would tend to flatten the net energy requirements over the year.

Figure 1: Distribution of Daily Load and Solar Output

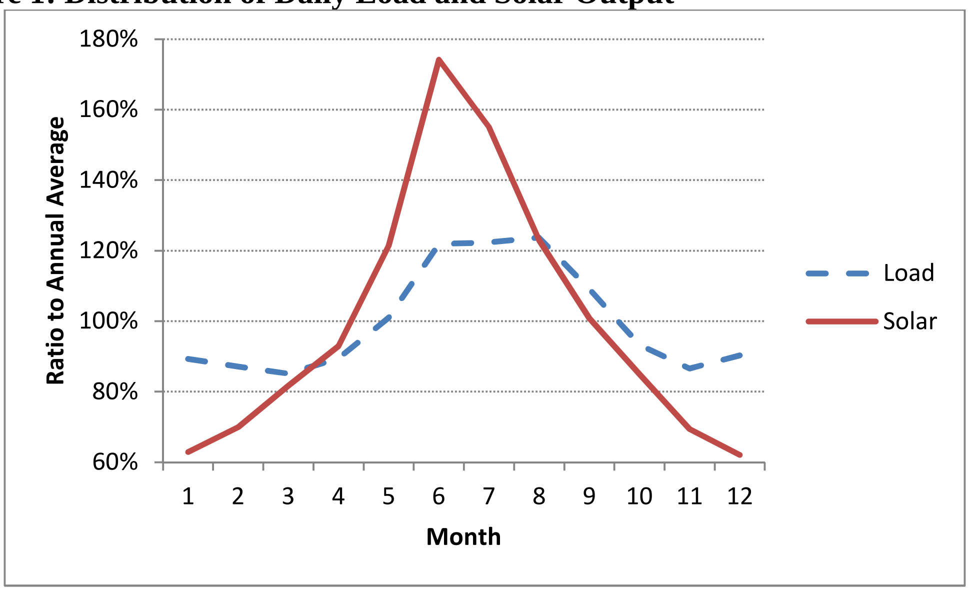

Table 2 shows EPE's summer peak hours in 2010–2014 and the ratio of photovoltaic output in those hours to annual average. None of the twenty highest loads in any year occurred outside the June–August period, and the average solar output on a top-twenty hour was 367% of average annual output. Since the residential load factor is about 60% (OPUC 1-012), the residential load at peak is about 167% of the average residential load; solar provided much more system load relief per kWh than residential load imposes, suggesting that the reduction in customer generation and transmission bills per kWh of solar generation should be about twice the comparable residential bill.

Table 2: Top 20 Hours Annual, 2010-14

Number of Peak	Solar as % Annual Average

	Hours Hour Ending					Hour Ending				
Month	**14**	**15**	**16**	**17**	**18**	**14**	**15**	**16**	**17**	**18**
June	7	14	16	8	1	524%	478%	402%	278%	129%
July	2	5	4	1	0	443%	400%	352%	244%	111%
Aug	9	15	16	2	0	366%	330%	273%	199%	92%

Q: Does EPE offer any evidence on the level of solar generation at the system peak hours?

A: Yes, but it is contains multiple errors. El Paso Electric asserts that “a typical solar DG system in the EI Paso area is producing at peak between 11:00 am and 1:00 pm in every month. Systems peak at noon in three of EPE's four summer months.” (IR Eco 1-39b) This is an interesting answer, for two reasons. First, it is factually incorrect. The EPE system tends to peak in the hours ending at 2 PM, 3 PM, and 4 PM, not noon, as summarized in Table 2. Second, it suggests that EPE believes that solar only contributes to meeting load at the hour of peak solar output. While solar output is highest in the period from 11 AM to 1 PM, it is still higher in the system peak hours than on average over the year.

El Paso Electric gets closer to reality in a later response, but still confuses the facts:

> EPE's system peak typically occurs between 3 pm and 6 pm during summer months (June through September). While customer-sited solar DG facilities are producing energy in these hours, they are typically operating at 25% to 40% of their peak capacity in those hours, based on sample PVWatts data for a 4 kW system in EI Paso. DG system output declines significantly between 5 pm and 6 pm. (Sunrun 1-7)

In this case, EPE misstates the time of its peak loads. The monthly peak loads have occurred between 1 PM and 4 PM (hours 14 to 16), and of the twenty highest hours in each of the last five years (a total of 100 hours), only 12 were after 4 PM and only one after 5 PM. As shown in Table 2, solar output in the actual peak hours is generally much higher than average. The average over the 100 high-load hours is over 50%, and the average in the monthly summer peaks was 48%.

Interestingly, Mr. Novela's Exhibit GN-7 (Figure 7) shows the summer peak occurring in the hour ending 1600 (4 PM), a much more representative time than the period Mr. Schichtl claims.[5]

Similar confusion is apparent in Mr. Schichtl's testimony, in which he conflates system peak with customer non-coincident peaks:

> Because EPE's system typically peaks later in the afternoon, solar generation systems are producing below their peak capacity when demand on EPE's system is at its peak. These factors contribute to a reduced allocation of production costs to the Partial Requirements class than would otherwise be the case. However, data also indicates that the peak demand for partial requirements customers is not markedly different than that for similar size full requirements customers, because their peak occurs even later than system peak when DG production is significantly reduced. (Schichtl direct at 32)

This passage starts with a discussion of EPE's system peaks, and then uses the term "peak demand" to refer to the NCPs of the distributed generation customers.[6] Mr. Schichtl does recognize that solar generation reduces generation costs, but he ignores the load reductions on transmission and distribution, and seems to suggest that photovoltaics do not contribute to reducing loads on distribution equipment.

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[5] Mr. Novela also presents data on the effect of distributed generation on the winter system peak; since EPE does not treat any costs as being driven by the winter peak, this aside is not relevant to the cost of serving customers with distributed generation. Exhibit GN-7 also compares the entire household load of the distributed-generation customers to average and stratum 4 non-distributed-generation customers, although EPE does not serve all the household load of the distributed-generation customers.

[6] In the process, Mr. Schichtl raises the irrelevant point that solar panels are usually producing less than their full capacity. This point would be relevant if someone were arguing for crediting solar generation as if it produced energy at 100% capacity factor, but distributed generation customers reduce their energy bill only in proportion to solar output.

Q: Has EPE offered any information about the contribution of solar to reducing peak loads on transformers, feeders, and distribution substations?

A: No. It is not clear that EPE knows when that equipment peaks.

Q: Did solar output mitigate loads on the distribution system serving residential customers at the time of the Rate 01 residential MCD in 2014?

A: Yes. That residential MCD occurred in the hour ending 5 PM on July 5, 2014. In that hour, EPE estimates that the average distributed-generation customer supplied 35% of its load at the residential diversified peak hour. (OPUC 1-012).[7] The load of EPE's distributed-generation customers was also 35% lower at the overall residential peak than at EPE's estimated coincident peak of the distributed-generation class (June 30 at 7 PM), when the distributed-generation systems were providing less than 5% of the DG-customer load. Using the later 7 PM hour overstates the contribution of the distributed-generation to primary lines and substations by over 50%.

Q: Do you have any estimate of the effect of solar output on peak transformer loads?

A: Yes. At the four summer CP hours (when some 86% of the non-DG residential customers hit their NCP), the distributed-generation research sample is drawing only 28% to 35% of its combined NCP. El Paso Electric's estimate of solar output in those hours for the average residential distributed-generation customer is about 1.26 kW (OPUC 1-012, Attachment 1).

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[7] El Paso Electric sometimes uses the term "Maximum Diversified Demand," or MDD, rather than MCD.

VI. Embedded Costs of Service for DG and other Residential Customers

A. Generation

Q: How does EPE allocate generation plant costs?

A: El Paso Electric uses the average-and-excess demand (AED) allocator, which is mathematically and practically indistinguishable from a pure demand allocator for most purposes. While the AED purports to allocate some portion of fixed costs on energy (which is the same as an average-demand allocator), the operation of the "excess" portion of the formula brings the total allocation back to nearly the same percentages as a simple demand allocator.[8]

Q: What measure of demand does EPE use in its generation allocator?

A: El Paso Electric uses the average of the peak hour for each of the months from June to September. These are not the four highest hours in the test year, and they represent a small portion of the hours that contribute to the need for capacity, but they are a rough representation of the sorts of loads that contribute to reliability-related capacity needs. Given the large differences in EPE's loads between summer and winter, it is likely that these four months are reasonably representative of the bulk of the hours that contribute to EPE's reliability requirements.[9]

B. Transmission

Q: How does EPE allocate transmission costs?

A: El Paso Electric's position is summed up by its witness Manuel Carrasco:

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[8] El Paso Electric does not treat the portion of costs allocated on the average component of the AED allocator as energy-related in the COSS.

[9] Of the 100 highest hours in 2013, only eight were outside this period, and they were all in May.

> Because transmission is primarily built to meet the peak demand of EPE's service territory, and is not affected by energy needs, transmission costs are allocated on the 4CP method… (Carrasco Direct at 18)

While this approach ignores the justifications for some transmission (e.g., importing baseload energy from remote coal and nuclear facilities to economically meet EPE’s energy requirements), it roughly reflects the most important driver behind EPE’s transmission costs, high summer coincident loads.

C. Distribution

Q: What is EPE’s approach to allocating distribution plant?

A: El Paso Electric subfunctionalizes distribution plant into two components, which it allocates differently:

- Substations and primary lines
- Secondary lines and line transformers

The first category, the primary system used by all distribution customers, is about 67% of the claimed costs that EPE allocates to residential customers (Schedule P-6).

In its list of distribution costs in Schedule P-6, EPE included a category of “demand distribution load dispatching,” even though the COSS lists zero expenses under Account 581, distribution load dispatching. I am not aware of anything that can be considered dispatch of the secondary distribution system. I thus treated this category as primary-related.[10]

The second category, the secondary system, is dominated by the line transformers, which constitute 78% of the costs (Schedule P-6).

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[10] Indeed, EPE’s unbundled COSS for distribution load dispatching indicates that this category includes all the substation costs (Workbook EPTXDLD.xlsm in EFCA 1-043). The substation category appears to actually consist of poles. EPE’s cost-of-service workpapers (e.g., in Schedule P-6) may contain other inaccuracies.

Q: How does EPE allocate substations and primary lines?

A: El Paso Electric allocates this equipment on the classes' MCDs, which would normally occur in the summer.[11]

Q: Is this a sensible approach to allocations of primary distribution?

A: It is a common approximation. The use of MCDs to allocate primary distribution implicitly assumes that each rate class has its own separate set of feeders and substations, and that the capacity of that equipment is driven by the class's MCD. Some utilities have at least some feeders and substations whose load is dominated by one class.

Unfortunately, most feeders (and even more so, substations) serve more than one class. Even if the peak loads on a particular feeder are mostly driven by residential, for example, that feeder will include streetlighting, traffic signals, and probably some commercial and other loads as well. Streetlights and signals do not have their own feeders and contribute to primary equipment costs only to the extent that they have load coincident with the other classes on the feeder.

The data in EFCA 1-008 indicate that over half the commercial customers with distributed generation are on feeders with residential DG customers, and 24% of residential distributed-generation customers are on feeders with commercial distributed-generation customers.[12]

Q: What are the implications of this mixing of rate classes on feeders and substations?

[11] While load in the peak hour for any particular piece of equipment is important, so are loads in other high-load hours around the peak, since they contribute to the heating that reduces the load-carrying capacity of the equipment in the peak hour. Even off-peak energy use on hot days will contribute to overloading and degradation, by keeping the equipment from cooling off overnight.

[12] The percentage of residential customers sharing a feeder with commercial customers is almost certainly higher than this, since most commercial customers do not have distributed generation.

A: The use of the class MCDs for this purpose may be the best available option for broad customer classes, such as residential, commercial and industrial, for a utility that has limited data on the timing of peak loads on its distribution equipment.[13] Even at that level, the results should be taken with a large grain of salt. For smaller rate classes scattered among the larger rate classes, the class MCD is inappropriate for allocating primary distribution, and will generally overstate the costs caused by those smaller classes.

Q: What is the significance of this observation for setting rates for customers with distributed generation?

A: Since the DG customers are mixed in with similar customers without DG, allocating primary distribution costs on the MCD of a group of DG customers overstates the share of primary distribution costs attributed to DG customers.

Q: How does EPE allocate transformers and secondary lines?

A: EPE allocates those costs on the sum of customers' undiversified maximum demand (which it calls non-coincident peak, or NCP), regardless of the time of those peaks.

Q: Is allocation of secondary distribution on this non-diversified demand appropriate?

A: No. Use of the NCP allocator assumes that EPE builds its secondary distribution system to meet the sum of the historical non-coincident loads of each customer who uses that equipment. This description of the distribution planning process is not correct. Distribution planners do not know the historical non-coincident load of each customer, and would not use those data for sizing distribution if they were

[13] El Paso Electric indicates that it does not have comprehensive data on the timing of feeder peaks (IR EFCA 1-8(f) and (g)); it is not clear from that response whether EPE has any such data.

available. Prudent distribution investment is driven by the coincident loads expected for the equipment.

Typically, many residential customers share a transformer, and the loads of those customers tend to be highly diverse. In IR OPUC 5-10, EPE provides its planning estimates of the diversity of peak loads among similar residential customers sharing a transformer. These data are reproduced as Figure 2 and are consistent with the diversity in the COSS.

Figure 2: EPE Estimate of Residential Diversity

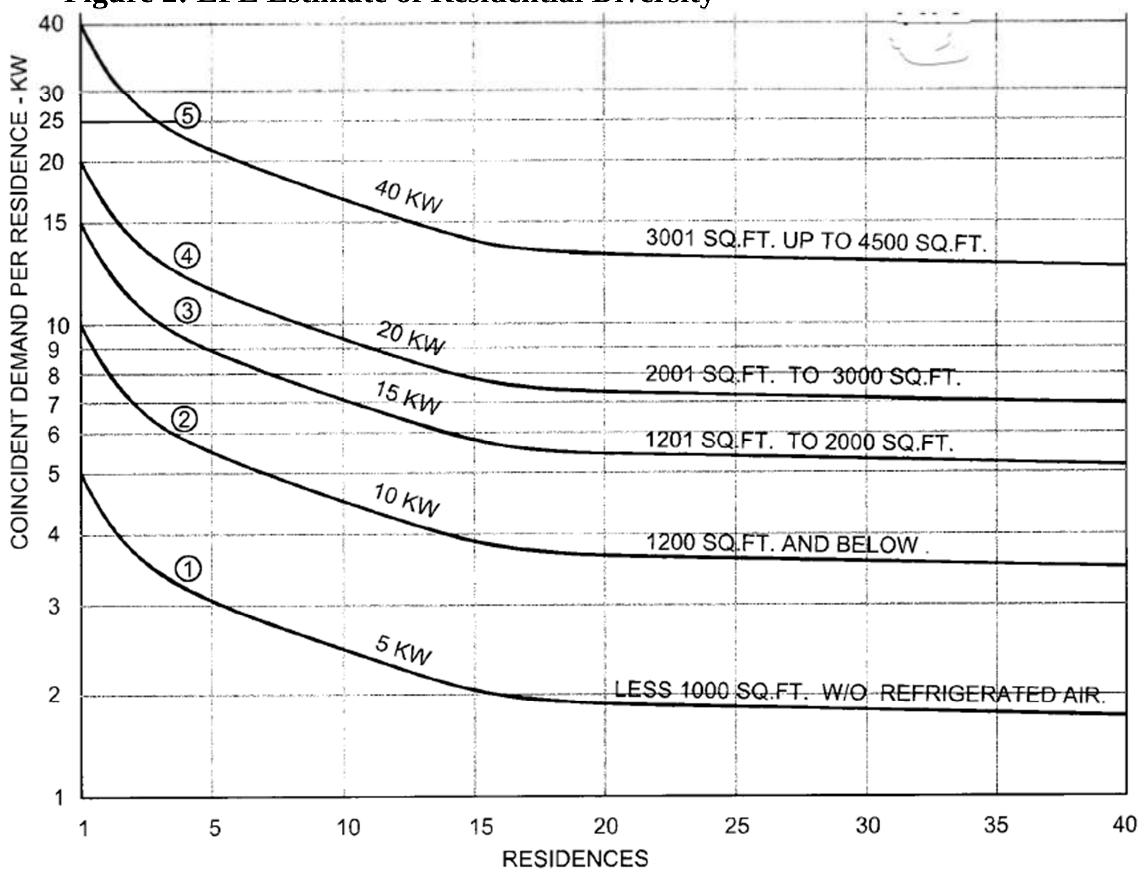

Table 3 applies the diversities from Figure 2 to the customers-per-transformer data that EPE provided in IR EFCA 1-013 for transformers with distributed-generation customers. On average, the contribution of residential customers to the transformer peak is about half the customer NCPs.

Table 3: Diversity of Customers on EPE Transformer Sample

Customers per Transformer	Diversity	Customers Number	%	Weighted Diversity
1	100%	39	1%	0.8%
2	80%	62	1%	1.1%
3	67%	57	1%	0.8%
4	63%	184	4%	2.5%
5	60%	205	4%	2.6%
6	57%	354	8%	4.3%
7	53%	252	5%	2.9%
8	50%	392	8%	4.2%
9	50%	252	5%	2.7%
10	47%	440	9%	4.4%
11	43%	231	5%	2.1%
12	43%	828	18%	7.6%
13	43%	273	6%	2.5%
14	40%	294	6%	2.5%
15	37%	45	1%	0.4%
16	37%	128	3%	1.0%
17	37%	102	2%	0.8%
18	37%	126	3%	1.0%
19	37%	57	1%	0.4%
20	37%	180	4%	1.4%
21	37%	42	1%	0.3%
22	37%	44	1%	0.3%
26	37%	52	1%	0.4%
27	37%	27	1%	0.2%
total		4,666		47.4%

Q: Is there similar diversity on the secondary lines?

A: Yes, although few customers share each span of secondary line, so there is less diversity than for line transformers.

Q: What are the implications of the diversity of loads on residential line transformers?

A: In EFCA 1-013, EPE provides the number of distributed-generation customers and non-distributed-generation customers on each of 567 transformers, serving 742 distributed-generation customers and 3,924 non- generation customers. The average residential DG customer shares its transformer with 6.8 other customers, 5.6 of which do not have generation. Thus, 72% (5.6 ÷ 7.8) of the customers on the typical transformer serving DG do not have generation, and the peak loads on the transformer will normally be driven by the loads of customers without DG. Thus, the contribution of the distributed-generation customers to transformer costs will usually be driven by their contribution to the maximum demand of the non-generation customers whose transformers they share.

Q: How should these insights be applied to the design of rates for distributed-generation customers?

A: As long as EPE allocates secondary distribution costs in proportion to customer NCP, those costs should be divided between distributed-generation and non-generation customers in proportion to energy, or loads in the hours in which transformers are highly stressed. Since EPE does not appear have any data on the times of transformer loadings, total energy is the only readily-available allocator of secondary costs within the residential class.

D. Conclusion on Cost Allocation

Q: What do you conclude from EPE's COSS allocation methodologies?

A: EPE's proposed allocation methodologies, especially for distribution-related costs significantly overstate the costs to serve DG customers. As such, EPE has not adequately demonstrated that 1) the costs associated with serving DG customers is unique and/or burdensome enough from the residential class to merit its own mandatory tariff; and 2) its proposal to include a demand-charge in both Rate No. 03 to recover capacity-related distribution costs is cost-based or even necessary.

Q: How should EPE change the COSS to more appropriately allocate costs to the DG customers?

A: EPE should simply leave DG customers with residential customers and continue to allow them to take service from Rate No. 01. While this approach would overstate some costs of service per kWh for DG customers, since every kWh of sales to a DG customer is associated with a smaller amount of coincident peak and class MCD, DG customers are residential customers and should continue to be treated as such.

Q: Are there any other cost-allocation issues that should be developed further in future proceedings?

A: Yes. I would include in that category:

- The distribution of peaks and high-load hours on feeders and substations, so that the costs of those facilities can be allocated on the loads that drive the need for capacity, rather than the arbitrary class MCD allocators.
- The distribution of peaks and high-load hours on line transformers (probably using simulations based on the load-research sample), to recognize the diversity of customer loads on transformers, particularly for DG customers.[14]

The effect of load shape on energy costs, including both variable costs and the higher fixed costs incurred for lower fuel costs (e.g., for Palo Verde and wind plants).

VII. EPE's Proposed Rate Design is Unjustified, Inefficient and Confusing to Customers

A. EPE's Proposed Rate Design

Q: What is EPE's approach to rate design?

[14] This improvement in the allocation will likely reduce the allocation of transformer costs to the entire residential class.

A: As described in Mr. Schichtl's Direct (at 17–19), EPE seems to apply two basic principles: base the rate design on the COSS, and charge capacity costs through fixed charges wherever possible.

Q: What are the flaws in EPE's approach to rate design?

A: El Paso Electric's approach to rate design has three basic flaws:

- The embedded cost study, if properly performed, should serve as the principle guide to cost allocation, but it should have limited application in rate design. Rate design gives customers signals about the costs of consumption and the benefit of conservation, and thus should be driven primarily by marginal costs and incentive effects, not embedded costs.
- El Paso Electric conflates two meanings of the term "fixed."
- Fixed charges should generally recover only costs that increase roughly linearly with the number of customers (in the case of customer charges) or that vary with the customer's connected load or non-coincident maximum demand (in the case of monthly maximum demand). All other costs should be recovered through charges that reflect the volume of service that the customer takes, as total energy, coincident peak, or other charges for usage in high-load hours.

Q: What is the difference between cost allocation and rate design?

A: The purpose of cost allocation is the equitable sharing of historic embedded costs among rate classes. The purpose of rate design is to communicate to customers the effect of their loads on utility costs and encourage efficient levels and timing of usage.

Q: Why should marginal costs be the basis for rate design?

A: Marginal costs indicate the value of load reductions and the cost of load increases. Rates based on marginal cost provide a cost-effective signal to the customer making decisions about usage and investment in conservation, fuel switching and solar installation. This year's loads and this year's investments by customers will affect EPE's decision to build more capacity (generation, transmission or distribution) for future years. As I discuss in Section VI, the loading of some equipment this year may result in failures and replacement costs this year.

Q: Is it appropriate to recover all fixed costs through fixed charges?

A: No. In part, EPE's argument for charging plant costs through a monthly demand charge is based on the conflation of two meanings of "fixed costs." One meaning of fixed with reference to costs is fixed over load, and not avoidable by reducing load. Another meaning of fixed is fixed over the year; the cost does not vary in the short run. It is true that EPE's plant costs in the test year are largely determined by the cumulative investment and construction commitments in the past. Most plant investments require some years of lead time for permitting and procurement. However, even though EPE's non-fuel generation and transmission costs are overwhelmingly fixed over the year, none of them are fixed over load, since generation and transmission is added only for load-related reliability and energy savings.

Q: Why is rate design important?

A: Rate design gives customers incentives to reduce, increase, or shift load. Poor rate design will encourage wasteful usage and expensive efforts to switch loads from low-cost to high-cost periods.

Q: What is the residential rate design proposed by EPE in this proceeding?

A: As discussed earlier in my testimony, EPE is proposing to require that residential DG customers take service under a Rate No. 03, a DG-only three-part rate consisting of fixed, energy, and demand charges, rather than continue to serve these customers on the current two-part non-demand residential rate. In addition to requiring DG customers to take service on a DG-only rate with mandatory demand charges EPE is also proposing a more drastic increase to the monthly fixed customer charge for DG customers than for residential customers.

Q: Will EPE's proposed DG-only Rate No. 03 provide appropriate pricing signals?

No. The shifting of distribution cost recovery onto a monthly demand charge based on the customer's own 1-hour maximum load, regardless of time or coincidence with system demand, is confusing to residential customers and will not provide accurate price signals or appropriate incentives to conserve. In addition, as discussed earlier in my testimony, EPE's cost-allocation approach overstates the customer costs and could be used to argue for an inappropriately high customer charge in the future.

B. Customer Charges

Q: What is the effect of a customer charge on customer behavior?

A: The customer charge itself does not provide a useful price signal, since the customer cannot avoid it. Sometimes a large customer charge can cause perverse responses, such as discouraging a customer from switching from residential to distributed-generation rate.

Customer charges definitely have a downside. The greater the portion of the bill recovered through fixed charges, the lower the energy charges, the less the customer saves from energy conservation, the lower the incentive to conserve.

Q: What customer charge does EPE propose?

A: Under EPE's proposal, the monthly fixed customer charge for residential customers on Rate No. 01 would increase from $5 to $10, while the monthly charge for residential DG customers for Rate No. 03 would increase from $5 to $15.

Q: What cost justification does EPE offer for the higher customer charge?

A: According to the COSS, the unit customer cost for a partial requirements customer is $29.46, or about double the $15.48 cost of a non-DG customer (Schichtl direct at 23 and 34).[15] The $14 difference is due to two cost components: the higher cost of a bi-directional meter and the associated meter reading expense

Q: Is the COSS a reasonable basis for the Rate 3 customer charge?

A: No. It appears that both of these customer cost components are overstated in the COSS.

Q: In what way does the COSS overstate the Rate 3 meter cost?

A: As derived in the COSS, the cost of a meter for the DG customer is 3.17 times that of regular residential customers. This ratio is inconsistent with the replacement cost information provided in Schedule P-11. According to schedule P-11, the replacement cost of a bi-directional meter (including installation costs) is only 2.2 times the cost of a residential meter ($223 per meter versus $100.09 per meter).

Q: What is EPE's estimate of the meter reading component of customer charge?

A: EPE estimates that the meter reading expense associated with the bi-directional meter is 3.17 times that of the meter reading expense associated with the conventional residential meter.

Q: Did EPE base the allocation of meter-reading expense on an actual cost analysis?

A: It does not appear so. This allocation simply assumes that meter reading expense is proportional to the cost of meter.

Q: Is this estimate likely to overstate Rate 03 meter reading costs?

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[15] Interestingly, Schedule P-06 shows a customer cost for distributed-generation customers of $21.72, using more reasonable meter costs. Mr. Schichtl (Direct at 34) cites the cost of service study, not Schedule P-06.

A: Yes, for the following reasons:

- It is unlikely that a meter designed to be read electronically would require so much more of the company's resources. Since it is automated, it probably requires the same amount of time to read as a conventional meter.
- Since meter-reading is largely automated, the incremental cost per customer (which should be the basis of rate design) is probably much less than the average cost.

C. Demand Charges

Q: What demand charges does EPE propose for its Rate No. 03?

A: EPE proposes to introduce a demand charge in the new partial-requirements rate. Under the standard service rate, customers would pay $3.89 per month. Customers who choose the alternative time-of-use rate, would pay the same $3.89 per month in the winter months, a much higher charge of $11.75 per kW in the summer months.[16]

Q: What is EPE's basis for the $3.89 demand charge?

A: EPE states that it is "designed to recover the cost of distribution capacity and services" (Sunrun 1-22). As shown on page 10 of Schedule P-6, the value of $3.89 is taken directly from the unit distribution cost calculation performed in the COSS.

Q: Is recovering generation and transmission capacity costs in demand charges consistent with EPE positions on cost causation?

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[16] The magnitude of the proposed summer demand charge appears to result from a couple of errors in EPE's computation. In WP Q-7a, EPE divides the cost it intends to collect through the summer generation demand charge (in $/kW of coincident peak) by the four months, resulting in a price that (given EPE's stated intent) in $/kW of coincident peak over four months. But EPE then applies that to the much higher kW of billing load over six months. Correcting these errors would reduce the summer rate to about $5.70/kW.

No. First, EPE acknowledges that generation and transmission costs are avoidable in the long run and are driven by contribution to coincident peak rather than by NCP. [17] Second, EPE appears to recognize that demand charges are not an appropriate mechanism for reflecting costs driven by contribution to coincident peak.[18] Finally, EPE takes the position that the energy credit attributable to the PR class is "correctly reflected" in the energy charge.[19]

Q: What is EPE's view of the incentives created by demand charges?

A: Mr. Schichtl claims that demand charges "can incentivize systems which target peak demand reduction as opposed to simply offsetting energy. Residential DG systems can be configured to reduce the customer's household peak demand, which lowers billed demand" (Sunrun 1-46).

Q: If EPE sets demand charges based on its COSS, will the rate provide accurate price signals?

A: No, for the following reasons:

- Contrary to Mr. Schichtl's position, demand charges do not "target peak demand reduction," since they apply to customer maximum demands, not to the times of system peaks or equipment maximum loads.
- Embedded costs do not provide efficient pricing signals. Rate design should be based on marginal, not embedded, cost considerations. If energy charges do

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17 Sunrun 1-16.

18 EPE does not bill customers based on their coincident peak demand. Distribution costs, which are a function of customer non-coincident, are recovered through the proposed demand charge because these costs are not avoided when residential customers install generation. (IR Sunrun 1-1b)

19 The generation credit described by EPE attributable to the Partial Requirements class is applied as an overall reduction to the revenue requirement for the rate class. Because all generation capacity costs are reflected in the energy charges in the Partial Requirements rate, the generation credit is correctly reflected in the energy charge. (Sunrun 1-15)

not cover marginal costs, customers may make inefficient consumption decisions.[20]

- Some 67% of EPE's embedded distribution costs are allocated on non-coincident peak, not individual customer maximum demand (that is, billing demand). Allocation of generation and transmission is based on system coincident peaks.
- Demand charges do not provide appropriate incentives to conserve, even during high load hours.
- Not only are demand charges ineffective in shifting loads off high-cost hours, they may cause some customers to shift loads in ways that increase costs. For a customer who experiences its maximum summer demands at noon or 9 pm, a demand charge encourages the shifting of load into the afternoon peaks on the generation, transmission and distribution systems.
- Demand charges are very difficult for customers to understand, let alone mitigate.

Q: Please explain why demand charges do not provide the appropriate incentives.

A: Demand charges are a particularly ineffective means for giving price signals, for the following reasons:

- The demand-charge portion of the electric bill is determined by the customer's individual maximum demand. Capacity costs are driven by coincident loads at the times of the peak loads, not by the non-coincident maximum demands of

[20] For example, in Winnepeg, Manitoba, in 2007, the MTS Centre for sports events converted from all-gas heating to a system that uses electricity for most of its heating but switches to gas only to avoid demand charges at the time of the building's maximum loads ("MTS Centre Switches to Green Heating," Wiebe, L, *Winnipeg Free Press,* Oct. 30, 2007). The low rates for electric energy encourage the MTS Centre to use electricity rather than gas (for which it pays prices much closer to marginal cost), even on the peak hours for the generation, transmission, and local distribution systems.

individual customers. The customer's individual peak hour is not likely to coincide with the peak hours of the other customers sharing a piece of equipment, especially since the peaks on the secondary system, line transformer, primary tap, feeder, substations, sub-transmission lines, and transmission lines occur at varying times.[21] In fact, EPE's cost-of-service study (COSS) acknowledges that all transmission capacity is driven by fully diversified system peak, and most distribution demand by class diversified load, not by billing demand.

- Demand charges provide little or no incentive to control or shift load from those times that are off the customers' peak hours but that are very much on the generation and T&D peak hours. Customers can avoid demand charges merely by redistributing load within the peak period. Some of those customers will be shifting loads from their own peak to the peak hour on the local distribution system, on the transmission peak, or on the peak load hour of EPE. This will cause customers to increase their contribution to maximum or critical loads on the local distribution system, the transmission system, or the regional generation system.
- Demand charges are difficult to avoid; even a single failure to control load results in the same demand charge as if the same demand had been reached in every day or every hour.
- Rather than promoting conservation at high-cost times, or shifting of load from system peak periods, demand charges encourage customers to waste resources on the arbitrary tasks of flattening their personal maximum loads, even if those occur at low-cost times. For instance, in order to respond to

[21] This diversity is demonstrated for substations in RCM/TREE/MH I-7(p)); substations peak at different times, on different days, in different months, and in different seasons.

demand charges effectively, customers will need to install equipment to monitor loads, interrupt discretionary load, and schedule deferrable loads. Moreover, lower energy charges will encourage increased electric use, some of which will likely occur in the peak period.

Q: Please summarize your consolusions regarding EPE's proposal for mandatory residential DG demand charges.

A: EPE has not demonstrated that demand charges are cost-based or justified. Demand charges are confusing, do not sent effective price signales and are not cost-based. The Comision should reject EPE's propsoal to impose mandatory demand charges on any residential customer, espcially DG customers.

VIII. DG Customers Should be Fairly Compensated for Benefits Provided to the EPE Ratepayers

A. Avoided Capital Costs

Q: What components of EPE's costs can be avoided by DV, particularly solar PV?

A: DG can avoid generation, transmission and distribution costs.

Q. Please discuss the potential for DG to contribute to avoided generation costs in EPE's territory.

A: I identify at least two opportunities where DG can significantly contribute future avoided generation costs. First EPE in this rate case, EPE is requesting recovery of over half a billion in new generation investments that it has added to its portfolio since its last rate case in 2009, in order to meet a growing peak load..[22] EPE plans

[22] Buraczyk, p. 14.

to add combustion turbines and combined-cycle units in 2016, 2017, 2022, 2024, and 2025, supplemented with short-term purchases in 2021 and 2023, to meet load growth and replace the retiring capacity at Four Corners and EPE local gas resources (Rio Grande 7 and Newman 1–4. Additional resources will be required in 2026 to replace Copper and in 2028 to replace Rio Grande 8. Additional adoption of DG will help, and arguably could have helped, delay or avoid investments in new expensive capacity and as such will reduce costs to ratepayers.

Second, lower energy demand on the utility system will contribute to meeting a mass-based Clean Power Plan target, by allowing EPE to meet its energy requirements while burning less fuel. If Texas opts for a compliance plan based on emission rates, renewable energy, and DG specifically, can be included in the compliance formula.

Q: Please discuss the potential for DG to contribute to avoided transmission costs in EPE's territory.

A: EPE has invested in several transmission plant additions that are clearly load related. From 2009 through the test year end March 31, 2015, EPE completed transmission projects totaling about $99 million (Doyle direct at 13-14). From EPE's summary descriptions of these projects, it appears that almost half of these expenditures, or $44 million, were load-related (Doyle direct at 13–25 including Table RCD-3, IRs EFCA 2-53, 55, and 60). These projects include new lines and conductor upgrades to meet increased capacity needs.[23] An additional 25% of the major transmission project expenditures, or about $25 million, were associated with generation capacity additions. These investments are also load-related, but may be

[23] I excluded as non-growth-related expenditures that were replacements-in-kind of deteriorated or failed equipment and relocation of facilities.

more appropriately reflected as a part of avoidable generation costs. DG will help to reduce load and in turn, reduce the costs to ratepayers of new transmission investments.

Q: Please discuss the potential for DG to contribute to avoided distribution costs in EPE's territory.

A: Decreases in peak loads in high-load hours on the equipment and in energy loads around the peaks can avoid future distribution costs in the following ways, among others:

- Reducing existing load frees up existing distribution capacity for other customers and other loads and delays the need for additional capacity to serve load growth.
- In some cases, distribution equipment is already operating at or above design capacity and reducing existing load can avoid expenditures that would otherwise be required to catch up with past load growth.
- As older equipment wears out, current and expected load determines the sizing of replacement equipment.
- Existing distribution equipment wears out faster if it is more heavily loaded. The capacities of transformers and underground power lines are limited by the build-up of heat created by electric energy losses in the equipment. Every time a transformer approaches or exceeds its rated capacity (a common occurrence), its internal insulation deteriorates and it loses a portion of its useful life. Long hours of high loads result in heat building up in lines (especially underground lines) and transformers, increasing the damage of peak loadings.
- The capacity of overhead lines is often limited by the sagging caused by thermal expansion of the conductors, which also occurs more readily with

summer peak conditions of high air temperatures, light winds and strong sunlight. Overheating and sagging also reduce the operating life of the conductors.

EPE has invested in several distribution capital additions that are clearly load related. From 2009 through the test year end March 31, 2015, EPE completed about $253 million of distribution capital additions (Doyle direct at 25). Based on the summary descriptions of these projects, I estimate that at least a third of these expenditures, or over $90 million, were load-related (Doyle direct at 24-28 including Tables RCD-4 and -5, IRs EFCA 2-62, 63, and 66). These projects include additions of new distribution lines and transformers in areas with existing lines to meet loads of new customers or customer additions, increase in capacity of equipment to meet loads of new customers, new substations and feeders to address load growth, upgrade of transformers in existing substations. In addition, there are another $82.5 million of expenditures that EPE acknowledges were in part driven by load growth. Solar generation occurs at times of high load on distribution equipment. Reductions in loads on the distribution system will avoid future expenditures by making capacity available to serve load growth and by reducing overloads and premature aging of existing equipment.

Q: Does EPE acknowledge that these costs are avoidable?

A: Yes, however somewhat reluctantly. In response to a question about whether DG avoids capacity costs on EPE’s distribution, transmission and generation systems, Mr. Schichtl responds that DG has no near-term avoided cost value. In the long term, he recognizes that reductions in customer demand and in turn, system coincident peak, delay the need for additional system generating capacity. He concludes that because DG has less impact on the customer’s non-coincident demand, the long term impact on distribution capacity is less significant than the impact on generation capacity. (Sunrun 1-16).

Q: Is Mr. Schichtl's characterization correct?

A: Not entirely. First, DG has the immediate benefit of reducing generation line losses, and thereby reducing the need to procure additional generation to account for these losses. Second, lower loads reduce the probability of load-related failure of T&D equipment, even in the first year.

Third, Mr. Schichtl's assertion that reductions to the system coincident peak "may have the effect, other things equal, of delaying the need for additional system generating capacity" is a gross understatement, since EPE's generating capacity need is driven entirely by summer system loads. For planning purposes, EPE adds capacity to meet a requirement of the highest hourly load plus a reserve margin, while for the COSS EPE assumes that the peak load in each of four summer months drives capacity needs.

Fourth, Mr. Schichtl ignores avoided transmission investments, which EPE acknowledges are driven by peak load.

Fifth, Mr. Schichtl asserts that the customer's non-coincident demand drives all distribution investments. Even EPE acknowledges that investment in distribution substations and primary lines are driven by diversified load, which it approximates as class MCD. As I explain in Section VI.C, even investments in transformers and secondary lines are driven by diversified loads of the customers on each piece of equipment.

B. EPE's Proposed Value of DG

Q: How much capacity credit does EPE impute to solar facilities?

A: In Exhibit MC-3, EPE applies a “capacity attribution factor” of 70%, based on solar contribution to EPE’s four summer monthly coincident peaks, and treats 70% of each jurisdiction’s dedicated solar installations as a reduction in the jurisdiction’s load. Since EPE uses a 15% planning reserve margin, each kW of installed solar capacity is credited with 70% × 1.15 = 0.805 kW of conventional generation.[24] Since the 70% capacity credit is much higher than the average energy output of photovoltaics (about 42%, from ECO 1-39), each kWh of solar output is associated with about 1.67 kW of capacity value, just about what is required to support a kWh of retail load (at the residential 4CP load factor of about 60%, from OPUC 1-012).

Q: How did EPE value the excess solar energy sold back to the grid?

A: Mr. Schichtl mentions two different ways in which solar customers will be credited for their excess production. On one hand, Mr. Schichtl states that EPE used the cost of the 3 MW Montana community solar project, about 8.394¢/kWh, as a proxy for the value of the excess solar. [25]

Elsewhere in his testimony, Mr. Schichtl states that the solar customers will be paid “EPE's avoided cost of energy.” (Schichtl direct at 33)

Q: Is EPE proposing to credit the solar distributed-generation customers for excess power at the Montana solar cost or the avoided energy cost?

A: Neither. For generators of size 100 kW or less, El Paso Electric is proposing to pay only the lesser of a short-run avoided fuel cost and the monthly average fuel cost (Schedule Q-8.8, Schedule No. 48). The avoided fuel cost would be computed as the average of peak and off-peak values, even though the vast majority of solar

[24] In its May 15, 2015, Loads and Resources table (Staff 12-003), EPE treats its solar entitlements as resources, rather than load reductions.

[25] Schichtl direct at 36, ECO 1-50.

energy is delivered to the system in peak hours and very little in the off-peak hours.[26]

Q: Do energy loads affect the fixed costs of generation?

A: Yes. Higher energy requirements justify the construction or purchase of resources with higher fixed costs and lower fuel costs, including Palo Verde, combined-cycle plants, or even the high-efficiency LMS-100 combustion turbines.

Q: What price does EPE propose to pay distributed-generation customers for their net production?

A: According to the testimony of Mr. Schichtl (p. 33), the distributed-generation customers will be paid for any net production at EPE's avoided cost of energy pursuant to Rate No. 48. More accurately, Tariff Schedule No. 48 specifies that these customers will be paid the *lesser* of two prices: (1) the average energy cost in the billing month, which is an embedded cost, not an avoided cost, or (2) an average avoided energy cost estimated from the Company's annual avoided cost filing:

> the monthly energy payment rate shall be the lesser of the Company's cost of fuel and purchased power per kilowatt-hour (kWh) for the billing month in which the energy was received or, the Company's avoided energy cost as determined by averaging the Daily Peak and Daily Off-Peak values for one (1) megawatt (MW) from the Estimated Avoided Energy Cost for the current year as filed in the Company's most recent annual filing pursuant to PUCT §25.242 (e)(2)(A).

Q: Will this proposed price adequately compensate distributed-generation customers?

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[26] In Schedule No. 48, the rate for power purchased from non-firm distributed generators, the off-peak period includes only the hours from 9 PM to 8 AM (when there is little solar generation) and weekends and holidays (when residential customers tend to be at home). In any case, the Rate No. 48 avoided cost is unlikely to affect payments to residential distributed-generation customers, since their payment rate will be capped at the average fuel cost.

A: No. They can expect to receive no more than the average energy cost, which is at present only about \$0.02/kWh. This value is less than a quarter of Mr. Schichtl's estimate of the value of solar power delivered to the system.

Q: What do you conclude with regard to the credit that EPE should provide to DG customers?

A: EPE should increase the payment rate for net monthly deliveries by DG customers to the distribution system. A reasonable proxy for this payment would be the 8.4¢/kWh price of the 3 MW Montana community solar facility.

Q: Does this conclude your testimony?

A: Yes.