BEFORE THE STATE CORPORATION COMMISSION
OF THE STATE OF KANSAS

In the Matter of the General Investigation to	)	
Examine Issues Surrounding Rate Design	)	Docket No. 16-GIME-403-GIE
for Distributed Generation Customers.	)	

INITIAL COMMENTS OF WESTAR ENERGY, INC. AND KANSAS GAS AND ELECTRIC COMPANY REGARDING COST-BASED RATES FOR CUSTOMERS WITH DISTRIBUTED GENERATION

COME NOW Westar Energy, Inc. and Kansas Gas and Electric Company (collectively referred to as "Westar") and file their Initial Comments in the above-captioned docket. In support of its comments, Westar states:

I. Introduction

1. As the Commission indicates in its Order opening this docket, this docket was opened as a result of the settlement reached by Westar and other parties in Westar's last general rate case, Docket No. 15-WSEE-115-RTS (115 Docket). Order Opening General Investigation, Docket No. 16-GIME-403-GIE, at ¶ 2 (July 12, 2016) (Order Opening Docket). In the 115 Docket, the parties reached agreement – that was approved by the Commission – that

> the issue of whether a separate Residential Standard Distributed Generation Tariff is necessary, and, if so, ***how to structure the Residential Standard Distributed Generation Tariff in order to properly recover just and reasonable costs from customers with distributed generation*** should be deferred to a generic docket. Westar and Staff will work together to develop a procedural schedule for that generic docket in order to ensure timely resolution of the issues to be addressed.

Stipulation and Agreement (S&A), Revised Paragraph 39, Docket No. 15-WSEE-115-RTS (emphasis added).

2. In its Order opening this docket the Commission found:

> that when establishing an appropriate rate structure for DG customers the Commission must set rates that are just and

> reasonable. When determining rate structure the Commission has the discretion to consider the utility's quantifiable costs of providing service to a customer class, such as DG customers. Likewise, the Commission recognizes that quantifiable benefits of DG may decrease the utility's cost of providing service to DG customers . . . The Commission desires a thorough and thoughtful discussion of the appropriate rate structure for DG including the quantifiable costs and quantifiable benefits of DG. The Commission shares Westar' s concern regarding how benefits are to be quantified and allocated and will permit parties an opportunity to provide evidence showing that costs and benefits can be quantified and allocated in a manner which will result in just and reasonable rates for DG customers.

Order Opening Docket, at ¶¶ 8 and 10 (July 12, 2016).

3. In these Initial Comments, Westar will (1) discuss why customers with distributed generation (DG) should be charged a different, cost-based rate, (2) explain why the Commission should allow utilities to implement a three-part rate with a demand charge for private DG customers, (3) demonstrate that private DG customers do not, as a generic matter, provide verifiable, quantifiable system benefits other than displacing other energy when they export energy into the system, and (4) discuss how the implementation of a three-part rate for private DG customers can help foster the development of solar as an energy resource over the long-term. Westar is providing the Affidavits of Ahmad Faruqui, Ashley Brown, and Jeffrey Martin, attached hereto, in support of these Initial Comments.

II. The rate charged for service provided to private DG customers must be adjusted to be cost-based and non-discriminatory and to eliminate subsidies.

4. DG customers are partial requirements customers with different, and less predictable, load characteristics than non-DG residential customers and, thus, the rate designs for these two types of customers should be different. The current two-part rate structure is both unduly discriminatory and inequitable when applied to private DG customers because it does not recover

the costs private DG customers impose on the system and shifts costs to customers without distributed generation.

5. While the concept of DG is a relatively new one, the underlying associated logic is likely already familiar to the Commission and others informed on utility rate setting matters; that is, for a class of customers who continue to rely on the availability and capability of the utility system for their electric service except for a somewhat unspecified part of their energy supply. The familiar regulatory term for such customers is "partial requirements customers." Pairing the familiar notions of that construct to the more novel sounding "distributed generation" is helpful to bridging gaps in understanding. Accordingly, in these comments, Westar uses the terms somewhat interchangeably and as a means of comparison.

A. DG customers are partial requirements customers with different load characteristics than non-DG residential customers and should be charged based on a different rate structure.

6. Residential customers who self-provide a portion of their electric needs with distributed energy resources are partial requirements customers.[1] Brown Affidavit, at pp. 56-57. Residential customers with their own generation sources (whether it is solar or some other form of generation or energy storage) rely on the full capabilities of the electric utility system to meet all of their electricity needs not met by their self-generation. Faruqui Affidavit, at pp. 3-5. That occurs when private DG customers' own generation is not capable or is not available to meet all their requirements. When their generation is available, these customers have the ability to supply some of their electricity requirements from their own power source. However, regulated utilities

[1] Solar customers are a "unique type of partial requirements customer." Brown Affidavit, at p. 57. They don't "simply procure part of their power supply from suppliers other than the utility." *Id*. If that were the case, the relationship "would be defined by a contract that laid out the obligations of each party in discrete and clear terms. Rather, they are partial requirements customers for some of their energy supply, but rely entirely upon the utility for infrastructure and delivery services, for meeting all of their capacity requirements, and for backing up their energy supply when their solar units are not producing energy." *Id*.

are statutorily required to provide firm service to partial requirements customers for all their requirements when the customers are not able to use or fully rely upon their own generators for whatever reason (e.g.., the wind is not blowing, the sun is not shining, their demand exceeds their capacity to produce energy, or the generator is down for maintenance or repair). *Id*. As a result, the utility must have installed generating capacity, transmission capacity, and distribution capacity held ready for use of the partial requirements customers to serve the entire load of all private DG customers at any given time. The utility must also have customer service support systems in place to support service, billing, and all administrative capabilities for partial requirements customers. *Id*.

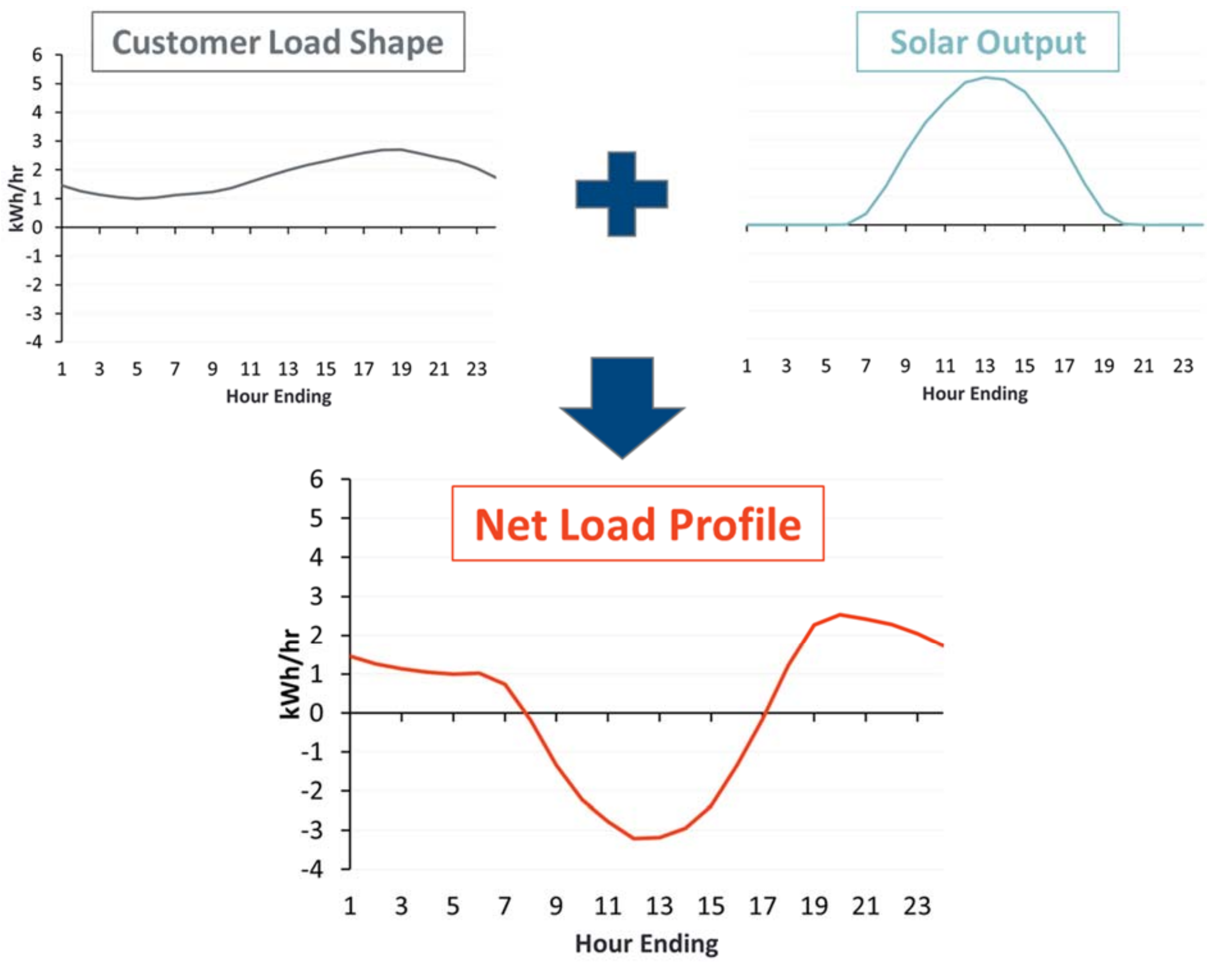
7. As Dr. Faruqui explains, "while a customer reduces his/her total energy needs by installing rooftop PV system, the customer still requires nearly the same amount of power grid infrastructure." Faruqui Affidavit, at p. 3. Even if a DG customer's net annual energy consumption were zero, "he/she still has significant demand during those system peak hours that drive the need for investments in infrastructure that are necessary to maintain a sufficient level of reliability." *Id*.

8. In fact, the existence of partial requirements customers and non-dispatchable DG resources on the system can actually increase the utility's costs to serve customers by complicating system planning, managing load flow, and system dispatch and by imposing additional administrative, transactional, accounting, and billing burdens on customer service operations. Faruqui Affidavit, at pp. 3 and 9-10; Brown Affidavit, at pp. 50-51, 55. As Mr. Brown explains, "unlike all of other energy resources whose siting is part of a carefully planned integrated process, in which the connecting infrastructure is often dealt with concurrently, or is capable of anticipation, distributed generation is completely outside of the utility's planning process." Brown Affidavit,

at p. 55. As a result, the utility has to "constantly play 'catch up,' a process which can be time consuming, costly, and lead to operation problems in the interim." *Id*.

9. Figure 2 from page 4 of Dr. Faruqui's Affidavit, reproduced below, illustrates a typical summer peak day for a partial requirements customer on Westar's system meeting some of his or her energy needs from solar panels.

Figure 2: Residential Customer Load Profile, Average Summer Day



Notes: Solar data based on Wichita, KS. Load data based on Westar's 2013 residential load research sample. Based on illustrative assumption that the solar PV installation exactly offsets the customer's annual electricity consumption.

10. During early morning hours of darkness, the DG customer is relying 100% on the grid for the energy the customer needs. As dawn breaks – assuming the sun is out and depending

on the directional focus of the solar panel, the DG customer is relying partially on increasing solar production and partially on grid power. During peak solar hours, again assuming the sun is out, the DG customer may be meeting all of his or her production from solar power, and may often be relying on the grid to sell excess production back onto the grid. During late afternoon and early evening – when the utility's peak occurs, solar production is insufficient to provide the customer's full energy needs and again he or she relies on both the DG and supplemental power from the grid to meet energy needs, only to be followed later in the day as dusk approaches with waning solar production and increasing demand off the grid. The solar customer is always relying on the grid in some manner – to import, export, or serve as back-up. *See* Faruqui Affidavit, at p. 4; Brown Affidavit, at p. 26.

11. Private DG does not significantly offset a utility's capacity costs because "solar production is often not coincident with system-wide peak demand" and because "solar production is intermittent, unpredictably so, and not dispatchable by the grid operator (i.e., the grid operator cannot call upon it to produce to meet peak demand or stop producing when there are system constraints or costs requiring it." Brown Affidavit, at p. 26. Westar is legally required to meet all of the electricity demand of customers in its service territory and is required to meet the SPP capacity reserve requirements. As a result, the existence of private DG "does nothing to avoid the need to incur the costs of meeting all demand . . ." *Id.*

12. There is substantial legal precedent supporting the concept that partial requirements customers should be charged a different rate than full requirements customers. The Federal Energy Regulatory Commission (FERC) has well-established precedent that addresses the question of rate design for partial requirements customers for both electric utilities and natural gas pipelines. *See*

Elimination of Variable Costs from Certain Natural Gas Pipeline Minimum Commodity Bill Provisions, 49 Fed. Reg. 22778-01, at 22780 (June 1, 1984).

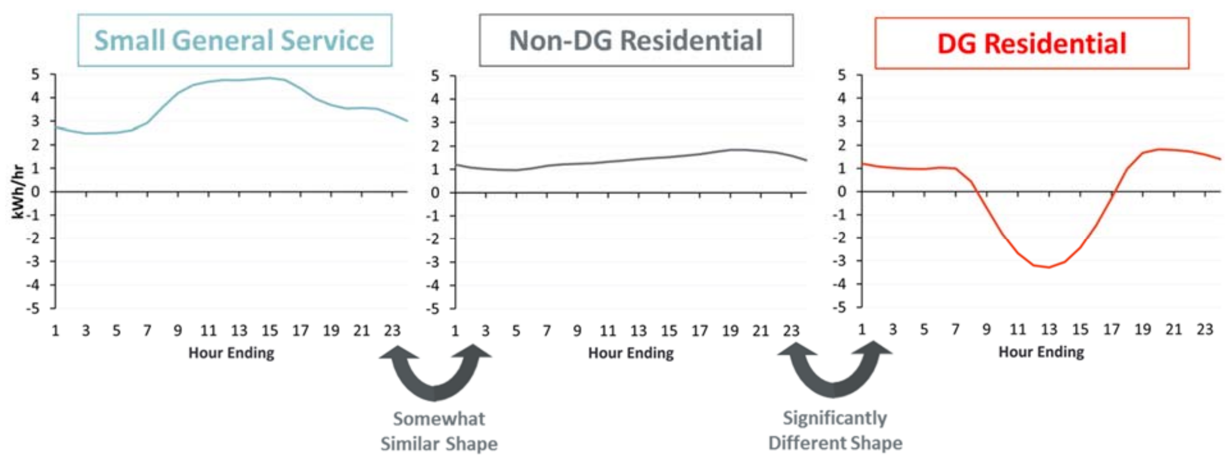
13. FERC has consistently recognized – for both pipelines and electric utilities – that utilizing a different rate and/or rate structure for a partial requirements class of customers is appropriate because of the differences in the way that the partial requirements customers utilize the system (e.g. load factor). *See, e.g., Panhandle Eastern Pipe Line Company*, 38 FERC ¶ 63002, Docket No. RP85-194-000 (Jan. 8, 1097) (upholding fixed cost minimum bill requirements for partial requirements customers because they "protect full requirements customers from bearing a disproportionate share of fixed costs resulting from swings off the system by partial requirements customers" and "merely assures that partial requirements customers will make at least a minimal contribution to the recovery of fixed costs on the system"); *Minnesota Power & Light Company*, 21 FERC ¶ 61233, Docket No. ER80-5-000 (90% demand ratchet for partial requirements customers was appropriate because "partial requirements customers have the opportunity to utilize alternative sources of capacity to control their load on MP&L's system. So, the ratchet is appropriate to compensate the utility for capacity it must hold ready for the use of its partial requirements customers in the event they choose to take it"); *The Connecticut Power and Light Co.*, 14 F.E.R.C. ¶ 61, Docket No. ER78-517 (Feb. 19, 1981) (finding that 100% demand ratchet was appropriate for partial requirements customers).

14. FERC has explained that the application of a full requirements rate to electric utility's partial requirements customers was not cost-justified and unacceptable because "it is obvious that the load characteristics of a partial requirements service may be quite different from the characteristics of full requirements service, and, as discussed above, the costs of a partial requirements peaking service would involve costs which differ from those of a partial requirements

base-load service." *Re Boston Edison Company; Intervenors: Municipal Light Board of Reading, Towns of Norwood, Concord, and Wellesley*, 23 P.U.R. 4th 416 (Dec. 9, 1977).

15. As Figure 6 from page 11 of Dr. Faruqui's Affidavit, reproduced below, demonstrates the load characteristics and factors impacting rates and rate design are materially different for a partial requirements residential customer with rooftop solar production than for a full requirements residential customer. FERC precedent would suggest that because of these differences, the rate design for these two types of residential customers should also be different.

Figure 6: Average Daily Load Profiles



Notes: DG net load calculated using NREL SAM data. Load profiles are annual averages.

B. The current two-part rate structure is unduly discriminatory and inequitable when applied to private DG customers because it does not fully recover the costs private DG customers impose on the system and shifts costs to customers without distributed generation.

16. Because of the differences in the load profiles of private DG customers and non-DG customers, Westar's current two-part rate for residential customers – which includes a large portion of Westar's fixed costs in the variable charge – is not cost-based for private DG customers and results in subsidization of private DG customers by traditional residential customers who have not installed generation at their homes.

17. According to Westar's last class cost of service study, filed in the 115 Docket by Westar witness Overcast, approximately 73% of Westar's generation, distribution and customer service costs to serve residential customers are fixed in that they do not vary with the amount of usage on the system but are related to demand for power (in the case of generation, transmission and distribution) and the number of customers (in the case of customer service). And, though the class cost of service study did not look at transmission costs because they are generally recovered through Westar's FERC-approved transmission formula and its retail Transmission Delivery Charge, Dr. Overcast did testify that virtually all the costs of transmission are fixed. *See* Overcast Direct, 115 Docket, at p. 5.

18. In the case of generation, fixed costs include the capital costs of constructing power plants. The only costs that vary with energy generation and consumption are fuel, some environmental compliance costs related to reactive agents in various emission control systems and a small amount of variable maintenance. Faruqui Affidavit, at p. 5. As with generation, the fixed costs of transmission and distribution are the costs related to constructing the facilities. The vast majority of Westar's costs of distribution and transmission are also fixed. *Id*.

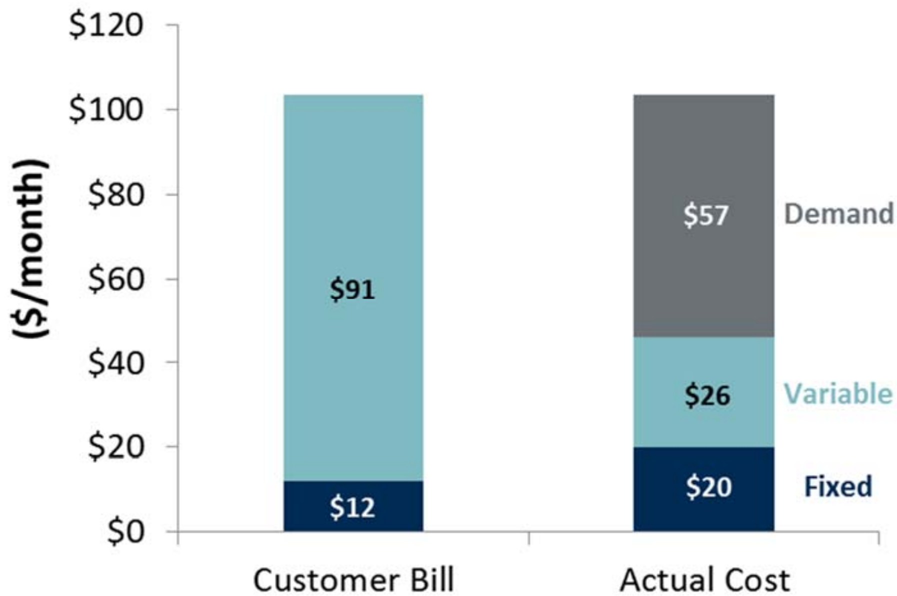
19. Many of the costs of providing customer service are fixed in that they do not vary with usage. Examples of such fixed costs that are included in the category of "customer service" costs are meters, the costs associated with meter reading (whether wages for meter readers or the installed costs of automated systems), the costs incurred by the utility to bill its customers, costs for customer service representatives, and costs related to distribution poles, service drops and related equipment. *Id*.

20. Westar's current residential rate design is a two-part rate with a $14.50/month fixed charge and "a variable charge that is, on average, around 12 cents/kWh over the course of a year."

Faruqui Affidavit, at p. 5. "In contrast, Westar's truly variable costs – fuel and variable O&M – account for only a modest fraction of the variable rate." *Id*. The remainder of Westar's costs are largely either "(1) customer costs, such as metering and billing, that are fixed on a dollars-per-customer basis, or (2) investments in generation, transmission, and distribution capacity which are sunk costs that are driven mostly by a combination of fixed and demand-related measures." *Id*.

21. As a result, there is a misalignment between the nature of Westar's costs and the rates being charged to residential customers, including residential customers with private DG. *Id*. at pp. 5-6. Figure 3 from page 6 of Dr. Faruqui's Affidavit, reproduced below, represents the misalignment. In a month when a customer's generation equals or exceeds his/her consumption, "he/she pays only the monthly customer charge, which is currently $14.50 (it was $12 in the year of the data behind Figure 3). Westar, however, incurs a cost of approximately $77 to serve that customer in that month, saving only on fuel and variable O&M costs, as well as potentially on line losses." *Id*.

Figure 3: Misalignment between Charges and Costs in Typical Residential Bill



Notes: Based on 2015 Westar revenue data. Westar's customer charge was $12/month at the time, but has since increased to $14.50/month. Revenue estimates exclude a small amount of revenue from the demand charge (0.4% of total residential revenue) in the Peak Management rate, which is not open to new enrollment.

22. Recovery of fixed costs through variable charges is not an ideal rate design for any customer; however, the negative effects of such a rate structure are amplified when considered in the context of private DG customers. Consider customers who install rooftop solar panels that completely offset their energy consumption over the course of the month. Because the sun does not shine 24 hours a day, this can only happen if the solar panels produce more than is consumed at the residence in some hours to offset those hours where energy production is reduced due to cloud cover or darkness. Faruqui Affidavit, at pp. 3-4.

23. Under an extreme example that includes a rate design with no fixed charge component, customers whose generation produces more than the customers consume in a given month will pay nothing for delivery service on their electricity bills. At the same time, however, they will still benefit from using Westar's generation, transmission, distribution, and customer

service facilities when the sun is not shining and the solar panels are generating no electricity and during cloudy periods when energy production is reduced and for the functionality the grid provides to allow the panels to produce. Faruqui Affidavit, at pp. 3-4; Brown Affidavit, at p. 24. In this circumstance, Westar essentially acts as a free backup battery for these customers – storing the customers' generation during periods of surplus generation and delivering it back to the customers when their consumption exceeds the output of their solar installations. Brown Affidavit, at p. 24.

24. Advocates of DG acknowledge – as they must – that DG production will at times exceed the DG customer’s consumption. They suggest that this excess is “banked” or “stored” on the utility system. Of course, nothing could be further from the truth. The electric industry is the ultimate just-in-time manufacturing business with the product being produced simultaneously with its consumption. Currently there is no economically feasible way to store electricity on large-scale systems.

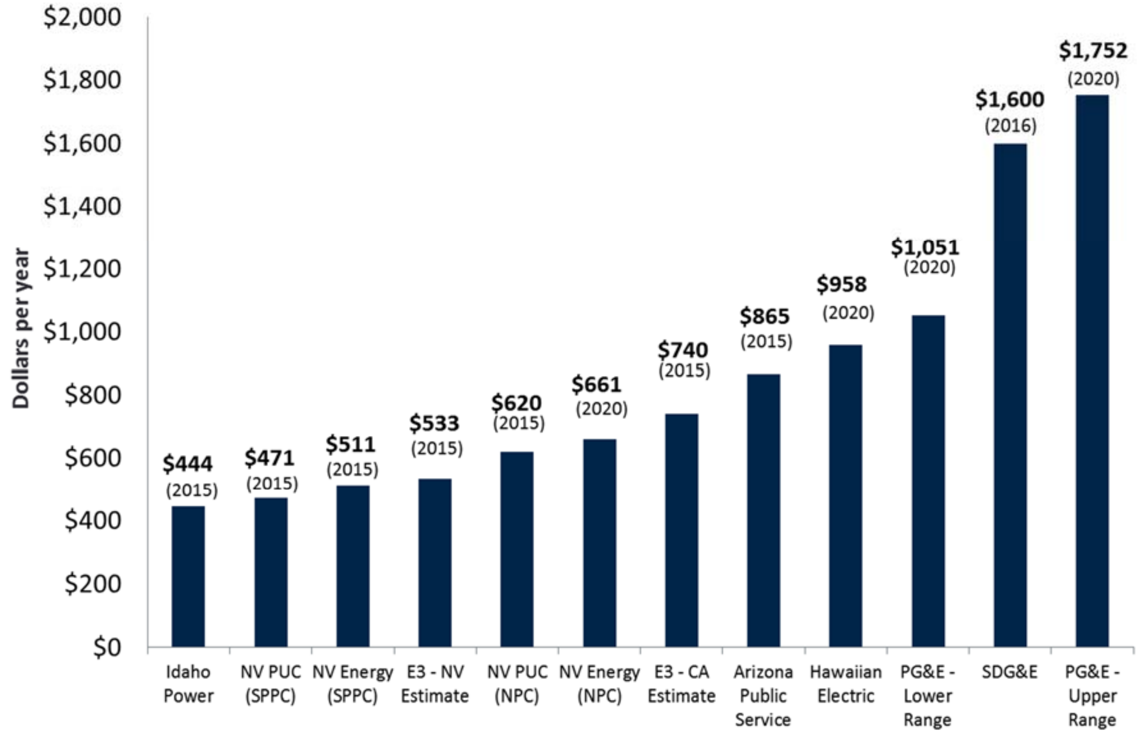
25. When private DG customers produce energy that is temporarily excess to their needs, the energy is not “stored” or “banked.” To the contrary, in that event, the serving utility must back off its own resources to compensate for the excess generation. At other times, when DG resources are not available due to darkness of night, cloud cover, maintenance or repair, or when on site production is inadequate to meet a solar customer’s demand, the utility must pick up the difference between DG generation and consumption by private DG customers with its own generation. These activities impose real costs on the serving utility that need to be charged to DG customers so non-DG customers do not subsidize them. Faruqui Affidavit, at pp. 9-10; Brown Affidavit, at pp. 19-20. This is completely consistent with a bedrock principle of regulation and price signaling, namely that the cost causer should pay. Faruqui Affidavit, at p. 14. Additionally,

the utility must have transmission, distribution, and customer service available to serve the DG customer when and as needed. Those services impose real costs on the utility. Those costs are not avoided by the utility when private DG customers' facilities generate and will be borne by other customers under the current rate design. Faruqui Affidavit, at pp. 3-5.

26. Under the standard rate, private DG customers avoid paying their fair share of fixed and demand costs when they substitute their generation for the utility's. Faruqui Affidavit, at pp. 5-7. The shortfall in cost recovery falls on non-DG customers. This creates an inequitable situation in which a hidden tax is placed on all non-DG customers to recover the fixed and demand costs of generation, transmission, distribution and customer service that are not being recovered from private DG customers when they rely upon such facilities as backup. Faruqui Affidavit, at pp. 7-9.

27. Figure 4 from page 8 of Dr. Faruqui's Affidavit, reproduced below, reflects the amount of the subsidy provided from non-DG customers to private DG customers in various states.

Figure 4: Rooftop PV Cost-Shift Estimates ($ per PV customer per year)



Notes: Year indicates date of cost-shift estimate, which is sometimes a forecast. In some cases, reported estimates were converted to annual dollars per NEM customer for comparison purposes. The PG&E ranges are calculated using assumptions from the California Public Utilities Commission's Public Modeling Tool. PPC and NPC refer to Sierra Pacific Power Company and Nevada Power Company service territories respectively.

28. Because installation of DG requires the investment of a significant amount of money (or the ability to finance such sums), DG is likely to be installed by higher income customers. Rates that require non-DG customers to subsidize private DG customers have the effect of taking money from lower income customers and giving it to higher income customers. Faruqui Affidavit, at pp. 8-9; Brown Affidavit, pp. 28-29.

29. To the extent that there is a policy goal of subsidizing investments in technologies like rooftop solar panels, this should be done explicitly by government, not by imposing a hidden tax on customers who do not have DG. However, the cost of solar panels has declined markedly in recent years, so the argument that solar is an infant industry in need of a boost is no longer

relevant. In fact, there is growing recognition that net metering artificially elevates the price of solar DG and prevents it from being more affordable and more attractive to customers on a non-subsidized basis. There is evidence that suggests that such subsidies are actually detrimental to the long-term viability of solar energy. Brown Affidavit, at pp. 32-34 (net metering does not "incentivize productivity or reliability. To the contrary, it harms the long-term reliability and competitiveness of the technology as a mainstream resource").

III. The Commission should allow utilities to implement a three-part rate with a demand charge component for private DG customers.

A. A three-part rate would be a just and reasonable, cost-based rate structure for private DG customers.

30. Use of a three-part rate for private DG customers addresses the issues discussed above that currently exist with respect to the two-part rate and private DG customers. Faruqui Affidavit, at p. 12; Brown Affidavit, at pp. 41-43. As Dr. Faruqui explains:

> By aligning the structure of the rate with the costs that it is intended to reflect, the unintentional shift in cost recovery from DG to non-DG customers will be ameliorated. With this new rate design, DG customers will be fairly compensated for the value of their output to the power grid and the subsidy from non-DG customers will be reduced or eliminated. A more cost-reflective rate will also encourage the adoption of emerging energy technologies and changes in energy consumption behavior that will lead to more efficient use of power grid infrastructure and resources.

Faruqui Affidavit, at p. 12.

31. A three-part rate consists of a fixed monthly service charge, a demand charge, and a volumetric charge. Faruqui Affidavit, at p. 12. Dr. Faruqui explains the components of the three-part rate:

> The <u>fixed charge</u> should be designed to cover the fixed costs such as metering, billing, and customer care. Sometimes it also covers the cost of the line drop and the associated transformer.

> The demand charge should be designed to cover demand-driven costs, such as distribution, transmission, and generation capacity. It is typically applied to the individual customer's maximum demand, either during a defined on-peak period, or regardless of time of occurrence, or based on a combination of the two. While the concept of demand is instantaneous, in implementation demand is usually measured over 15-minute, 30-minute or 60-minute intervals.
>
> The energy charge covers the cost of the fuels that are used to generate electricity, some variable environmental compliance costs, and power grid operations and maintenance (O&M). The demand charge and the energy charge might vary with the time of use of electricity and have different seasonal and/or peak/off-peak charges. Such three-part rates align the rate design with costs, a fundamental tenet of rate design.

Id. (emphasis added).

32. There is widespread and long-standing support in the industry and in the economics literature for the proposition that a three-part rate design is optimal design for electricity, satisfying the principles of economic efficiency and cost causation, reducing inequities in existing rates, and providing customers with an opportunity to reduce their bills through smarter energy management. Faruqui Affidavit, at pp. 12-13.

33. The three-part rate is the standard rate design for medium and large commercial and industrial customers in Kansas and other states, meaning that there is well-established precedent for designing such rates, enrolling customers, handling calls and doing all the other activities that attend to their offering. Faruqui Affidavit, at p. 18. The use of three-part rates for residential customers is also common across the country. There are currently at least 30 utilities offering three-part rates to residential customers in 17 states. Most of these rates have been offered for decades, including Westar's own residential peak demand rate. Faruqui Affidavit, at p. 18.

34. Moving fixed costs out of the volumetric charge and recovering them through a fixed charge (i.e., dollars per month) and a demand charge (i.e., dollars per kilowatt of maximum

demand per month) would restore fairness in rate design for private DG customers. Faruqui Affidavit, at p. 16; Brown Affidavit, at p. 42.

35. Collecting demand-related costs through a demand charge, fixed costs through a fixed charge, and variable costs through a time-varying variable charge, satisfies the ratemaking objectives of economic efficiency and cost causation.[2] Faruqui Affidavit, at p. 16; Brown Affidavit, at pp. 42-43. By better reflecting costs, a three-part rate will address the inequities that exist in the current rate designs, particularly as they relate to the under-recovery of fixed costs from private DG customers. *Id*.

36. The recovery of capacity costs through a demand charge is a particularly attractive feature of the rate. By recovering capacity costs through a demand charge rather than a fixed charge, a three-part rate avoids the challenge of automatically increasing bills for small customers, a common argument against high fixed charges. And unlike a fixed charge, the demand charge provides customers with a strong incentive and the ability to lower their bills by reducing their kW demands on the utility, which is beneficial to all customers by offsetting the need for the utility to build additional generation. Faruqui Affidavit, at pp. 20, 23-24.

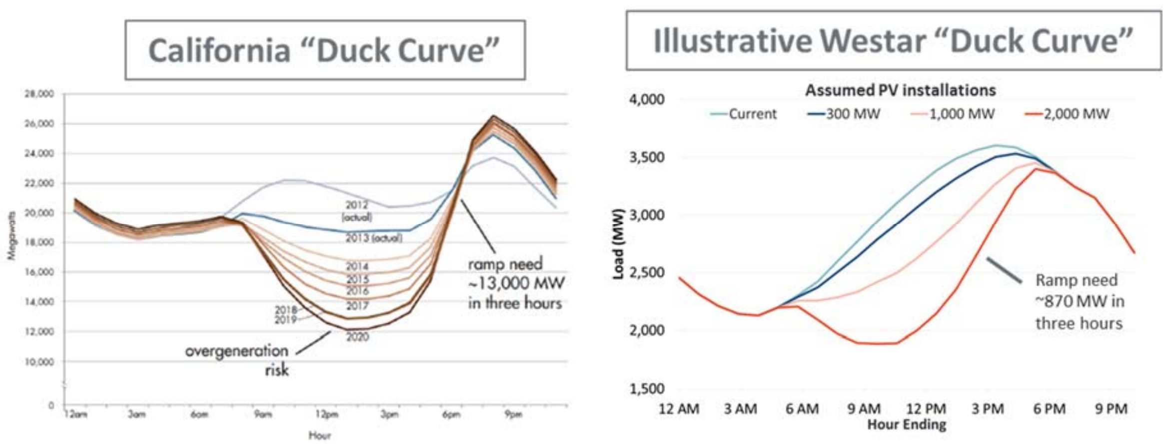
37. In addition to improving cost allocation among classes, the addition of a demand charge for partial requirements customers would incentivize distributed generation producers to engage in conduct beneficial to the overall cost of grid. The traditional non-time differentiated, demand insensitive, two-part rate design for traditional residential (non-DG) customers does not incent private DG customers to avoid sharply increasing demands on the utility and the grid (i.e., ramping up demand, particularly at peak)) when distributed generation production declines or

[2] It is important to note that while a demand charge may be a new line item on residential customers' bills, it is not a new cost imposed on customers. They have been paying for demand all along; the demand charge simply breaks out demand costs and makes them visible and manageable. Brown Affidavit, at p. 42.

ceases nor does it capture the associated costs from those who cause them. Brown Affidavit, at p. 42. However, by tying pricing to peak usage, the three-part rate creates the possibility for rewarding solar DG providers who are "most successful at providing on-peak, reliable energy to the grid, whether through installing their panels so they face west rather than south, installing batteries to operate in conjunction with their generation or adjusting their own consumption patterns to reduce their demands during on-peak periods and maximize the value of the energy they export to the grid." Brown Affidavit, at p. 42.

38. The impact of private DG customers on generation costs is demonstrated by the so-called "duck curve," a graph initially developed in California. The "duck curve" reflects the dispatchable generation the utility must provide to meet the demand of customers with their own generation when that distributed generation is not available. Figure 5 from page 10 of Dr. Faruqui's Affidavit, reproduced below, contains an illustration of the "duck curve" phenomenon using Kansas system load and solar profile data and illustrates the change in system load shape that would occur at various levels of PV installation (it is not intended to be a forecast of PV adoption in Kansas). It also shows the California "duck curve" for comparison purposes.

Figure 5: The California and Westar "Duck Curves"



39. This figure illustrates how quickly utilities must ramp up system generation to replace the lack of distributed generation, which declines as the overall peak demand increases. This happens because demand for electricity generally peaks later in the day than the peak output of the distributed generation. Faruqui Affidavit, at pp. 10-11.

40. With a properly designed demand charge, the rate for partial requirements service can incentivize the DG customer to both smooth this curve and moderate peak demand on the system – something not achievable with two-part rates. Brown Affidavit, at pp. 30-31, 42.

B. The Commission should allow utilities to implement a three-part rate for private DG customers through a compliance filing at the conclusion of this docket.

41. The Commission should issue an order in this docket giving utilities the option to implement a three-part rate for private DG customers through company-specific compliance filings at the conclusion of this docket. The three-part rate should include "a modest fixed charge, a flat year-round volumetric charge, and a seasonally differentiated demand charge." Faruqui Affidavit, at p. 15. Demand will be based on the "customer's maximum demand at any point in the billing cycle." *Id*. The three-part rate will be designed to be revenue neutral to the residential class as a whole.[3] *Id*.

42. Dr. Faruqui has developed an illustration of what the three-part rate would look like for Westar. It is shown in Table 2 from page 16 of Dr. Faruqui's Affidavit, which is reproduced below.

[3] If permitted to implement the three-part rate through a compliance filing in this docket, Westar would defer the additional amount recovered from DG customers as a regulatory liability and return it to the non-DG residential customers during its next general rate case.

Table 2: Westar's Current and Proposed DG Rates

Existing Rate		
Customer Charge	$	14.50
1st 900 kWh	$	0.075360
All Additional kWh (Winter)	$	0.061600
All Additional kWh (Summer)	$	0.083127
Proposed Three-Part Rate		
Customer Charge	$	14.50
Energy / kWh	$	0.042266
Demand / kW (Winter)	$	3.00
Demand / kW (Summer)	$	10.00
Riders (per kWh) - Applied to All Rates		
RECA	$	0.020114
TDC	$	0.016997
ECRR	$	-
PTS	$	0.000895
EER	$	0.000199

Note: ECRR is accounted for in the energy charge of the proposed rates. Net excess generation is assumed to be credited at 2.2 cents/kWh based on review of historical Westar data. The energy charge in the proposed three-part rate has been adjusted using the load research sample provided by Westar to maintain revenue neutrality.

43. Dr. Faruqui analyzed the potential impact of the implementation of a three-part rate on private DG customers. He concluded that the majority of DG customers would experience a bill increase of less than $40 per month. The median bill increase is "in the range of $20 to $30 per month." Faruqui Affidavit, at p. 22. He also explained that use of a three-part rate would allow customers to respond to the "new price signals by modifying their electricity consumption behavior" and that this would "mitigate a portion of the bill increases" for private DG customers. *Id*. at p. 23.

IV. The Commission should not consider unquantifiable costs and benefits when setting rates for private DG customers.

44. The Commission's Order Opening Docket, at paragraphs 8-10, indicates that it agrees with Westar that consideration of any non-quantifiable external benefits of distributed generation in this docket is inappropriate. Thus, the Commission stated:

> When determining rate structure the Commission has the discretion to consider the utility's quantifiable costs of providing service to a customer class, such as DG customers. Likewise, **the Commission recognizes that quantifiable benefits of DG may decrease the utility's cost of providing service to DG customers**.

Order Opening Docket, at ¶ 8 (emphasis added). From this language, it appears that any discussion of costs or benefits caused or provided by private DG customers will be limited to costs/benefits that "may decrease the utility's **cost of providing service**." This language precludes discussion or consideration of any alleged external, non-quantifiable benefits attributable to DG.

45. Westar continues to believe that consideration of **any** benefits of distributed generation – or the "value of solar" – in this docket is inappropriate for several reasons.

A. The Kansas legislature has already established the rate utilities pay customers with DG for energy produced in excess of the customer's own consumption.

46. As the Commission found in its Order Opening Docket, the Kansas Net Metering and Easy Connection Act and the Parallel Generation Act clearly address the rate an electric utility is to pay a customer with his or her own generation for energy produced in excess of the customer's own consumption (NEG or net excess generation). Order Opening Docket, at ¶ 9.

B. Consideration of the benefits of DG when setting rates for electric service improperly combines two issues.

47. The suggestion that the benefits of distributed generation production should be considered in setting just and reasonable rates for electric service improperly combines two separate issues – (1) the determination of the regulated price for energy the utility purchases from

customers with their own generation and (2) the regulated rate that the utility is allowed to charge customers for electric service.[4] To achieve the goal of transmitting appropriate price and cost signals to customers and energy producers in the most transparent way possible, regulated rates for electric service provided by utilities must be determined and charged separately from the regulated price a utility pays when purchasing energy.

C. Consideration of the unquantifiable benefits of DG when setting rates is inconsistent with cost-based ratemaking and Commission precedent.

48. Consideration of the benefits provided by a generation source such as wind energy, private rooftop solar or any other customer-owned generation is entirely inconsistent with the principle of cost-based ratemaking and with Commission precedent.

49. Historically, utility rates have either been determined by a competitive market – where one exists – or determined by a regulator based on the costs incurred by the utility. In jurisdictions where the regulators establish cost-based rates, the requirement that electric utilities' rates be cost-based is considered to be a substitute for competition. In either scenario – market-based or cost-based rates – there is no consideration of the "value" of external benefits provided by the technology being used to serve customers.[5]

50. As Mr. Brown explained in a co-authored article in The Electricity Journal:

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[4] These separate determinations have been combined through the use of net metering. However, this combination inappropriately obscures price signals and is based on the unfounded assumption that the appropriate price for distributed generation **energy** is always equal to the regulated commodity rate the utility charges for **electric service** – which implies the inclusion of the cost of transmission, distribution and customer service.

[5] Were the Commission to go down this path, it would not be a large leap to then introduce the social value of what one customer might use electricity for compared to another. Certainly, one could argue that electricity used in furtherance of public health, safety, or education has greater ultimate public good than electricity used, say, to power arcade video games or for a distillery to make liquor and spirts for consumption. The Commission does not have the legislative authority to set rates arbitrarily to encourage the former and discourage the latter and must set rates for different classes of customers based on the costs the utility incurs to serve them.

> [o]ptimally, prices for electricity are determined by a competitive market or, absent competitive conditions, should be derived from cost-based regulation. In both cases the prices are subject to an external discipline that should result in efficient resource decisions devoid of arbitrary or "official" biases. Subjective consideration of the "value" of particular technologies and where they may rank the merit order of "social desirability," effectively removes the discipline that is more likely to produce efficient results . . . . It is preferable to derive prices from the values established by either costs or market, not ephemeral and subjective considerations.

Valuation of Distributed Solar: A Qualitative View, The Electricity Journal, Ashley Brown and Jillian Bunyan (Dec. 2014) (attached hereto). Electric rates in Kansas are and have always been cost-based.

51. Introducing a new element into establishing rates – the consideration of the subjective, often theoretical, external and/or non-energy benefits of only one form of generation (solar generation owned by customers) – is inconsistent with well-established precedent and could result in unjust and unreasonable rates for all retail customers in Kansas. It is well established that "[t]he touchstone of public utility law is the rule that one class of customers shall not be burdened with costs created by another class." *Jones v. Kansas Gas and Electric Co.*, 222 Kan. 390, syl. ¶ 10 (1977). Similarly, rates should not be set in a way that discriminates in favor of some suppliers to the detriment of others. Using supposed benefits to reduce the rate to selective customers, or adjust prices paid to only a "preferred" supplier and not all suppliers, would fly in the face of this well-established doctrine. As Mr. Brown explained, "analyzing the 'value' of solar in isolation produces an essentially meaningless number, in the absence of similar 'value' analysis for all other competing resources. VOS studies are technology-specific (almost always limited to private rooftop solar) and almost always ignore market conditions and how the calculated value of rooftop solar compares with the value of competing resources to meet the same objectives." Brown Affidavit, at pp. 45-46.

52. Dr. Faruqui confirmed this conclusion:

> If a price has been assigned to a certain externality, in other words, if it has been internalized, and that prices is part of the utility's cost structure, then it is economically efficient to reflect the price of that externality in rates for all customers. However, it would violate the core principles of ratemaking if only certain customers or technologies were charged or compensated for their impact on those externalities.
>
> For instance, investments in rooftop solar PV that are artificially subsidized through the current rate structure could potentially instead be made in lower cost utility-scale solar or energy efficiency, while achieving many of the same benefits. All technologies and customers should be on a level playing field when developing residential rate design.

Faruqui Affidavit, at p. 25.

53. When Westar acquires or constructs a new generating facility, the Commission determines what the cost of that facility is and sets rates based on the cost that Westar incurred to build the facility to serve its customers. The Commission does not consider any external or theoretical system benefits the new generation provides, even though all such investments – including the new gas plant Westar built in Emporia several years ago, the major projects recently completed at Wolf Creek, construction of wind generation in Kansas, and Westar's new community solar projects – create external benefits such as jobs, enhanced economic development, property taxes, new public revenues, environmental benefits and public infrastructure improvements, for example.

54. When Westar acquired its 1,700 MW of wind generation over the last several years, the Commission did not even consider allowing Westar to calculate the value of installing wind generation on the system and recover more than the installed cost of the generation from customers, despite the fact that wind generation reduces NO_x and SO_2 emissions and is carbon-free. In fact, when Westar first added wind generation to its fleet, Westar asked the Commission to approve an

adder to its return on equity of 1% for its wind investment, as is authorized by K.S.A. 66-117(e) when a utility invests in projects or systems that can be "reasonably expected to produce energy from a renewable resource other than nuclear for the use of its customers." The Commission rejected the request stating that "the circumstances in this docket justify relieving ratepayers of the cost of an additional return in light of the close analysis involved in determining prudence and weighing Westar's PPA and ownership proposal." Final Order, *In the Matter of the Petition of Westar Energy, Inc. and Kansas Gas and Electric Company (collectively "Westar") for Determination of the Ratemaking Principles and Treatment that Will Apply to the Recovery in Rates of the Cost to be Incurred by Westar for Certain Electric Generation Facilities and Power Purchase Agreements under K.S.A. 2003 Supp. 66-1239*, Docket No. 08-WSEE-309-PRE, pp. 39-40 (Dec. 27, 2007).

55. As Westar installs community solar generation throughout its service territory, assuming the Commission follows its precedents, the Commission likely will not allow Westar to recover more than the installed cost of the generation from customers. This is the case even though if rooftop solar actually provides some external benefits, community solar would provide those same benefits, albeit at lower cost.[6] Valuing distributed generation at a premium based on supposed benefits would be inappropriate and unduly discriminatory. Such an approach would distort price signals related to generation sources even providing a benefit to distributed solar generation as compared to solar projects owned by Westar and used to supply its customers. Selectively compensating rooftop solar for value streams that are provided by other resources is not a fair and equitable approach to rate design. Faruqui Affidavit, at p. 25.

[6] In fact, given that the utility can choose the site for community solar, but cannot for other private solar units, the community solar facilities are actually more likely to provide system benefits than or randomly selected sites for private DG.

D. The benefits claimed to come from DG do not meet the Commission's standard for inclusion in the ratemaking process.

56. The Commission also found that it will only look at "the quantifiable costs and quantifiable benefits of DG" to determine the "appropriate rate structure for DG." Order Opening Docket, at ¶ 10. The Commission explained that it "shares Westar' s concern regarding how benefits are to be quantified and allocated and will permit parties an opportunity to provide evidence showing that costs and benefits can be quantified and allocated in a manner which will result in just and reasonable rates for DG customers." *Id*. However, studies of the benefits of DG or the "value of solar" are "highly subjective and readily manipulated, because there is no established methodology for assessing the value of solar, and furthermore, given the complexity of the analyses needed to assess all the various 'VOS' claims, no analysis can effectively avoid the need to make multiple subjective judgments." Brown Affidavit, at p. 43. In other words, the benefits claimed to come from DG (the "value of solar") do not meet the Commission's standard for inclusion in the ratemaking process.

57. Staff identified a list of possible benefits that could come from DG in its motion to open this general investigation docket (see pages 5-6 of Staff's Report and Recommendation in support of Motion to Open Docket). As Westar witnesses Brown and Martin discuss in their affidavits, none of these alleged benefits are adequately quantifiable to be considered in rates, there is no evidence that all DG, regardless of location, provides the alleged benefits, and it is equally likely that DG imposes additional costs on utilities' systems as opposed to providing benefits.

58. For example, solar generation does not reduce utilities' peak generation requirements. As has been discussed, solar generation production declines as the sun descends toward the horizon at the same time demand for electricity is peaking. The coincidence of these two events (shown graphically in the "duck curve" shown above) is to dramatically increase the

rate at which the utility must ramp its units to meet peak. And, because solar generation approaches zero at the time of the peak, solar generation does virtually nothing to reduce peak demand. Brown Affidavit, at pp. 47-48. However, to the extent private DG customers self-generate at peak, as was discussed above, use of a three-part rate that includes a demand charge will properly compensate such customers for their contribution to peak demand reduction.

59. Some DG advocates argue that DG enhances overall reliability because of their proximity to load. However, DG does nothing to enhance generation reliability or availability. As was discussed above, utilities operating in Kansas (and generally throughout the U.S.) must manufacture their product at the precise moment it is consumed without the use of storage, reliability must be ensured on a real-time basis. However, because DG resources are not dispatchable with availability that depends on the whims of the weather, DG resources cannot be counted on as reliable sources of energy. It is far more likely that the utility will provide backup to the DG generator than the other way around. Brown Affidavit, at p. 47; Faruqui Affidavit, at p. 3.

60. Additionally, solar generation will not be available to the DG customer or to the grid in the event the portion of the grid serving the private DG customer is down. Solar panels produce direct current (DC) electricity; the grid provides alternating current (AC) electricity. For solar DG to operate in tandem, the generated DC energy must be converted to AC energy and synced to the grid. A power inverter performs that conversion and syncing based on the signal it receives from the grid. As explained by Mr. Brown in his co-authored article in The Electricity Journal:

> During a system outage [affecting service to the DG customer from the grid,] the power inverter is automatically switched off to prevent the backflow of live energy onto the system. **That is a universal protocol to prevent line workers and the public from**

> **encountering live voltage they do not anticipate.** Thus, if a solar DG unit is functioning properly, when the grid is down, the solar DG customer's inverter will also go down, making it impossible to export energy. If the solar DG unit is not functioning properly, then the unit may be exporting, but will do so at considerable risk to public safety and to workers trying to restore service. The result is that the solar panel provides virtually no reliability to anyone other than perhaps to the solar host.

Valuation of Distributed Solar, id. at 38.

61. There is also no basis for any assertion that DG reduces transmission costs. As demonstrated by the "duck curve," it is apparent that DG does not reduce peak demand. Because the vast majority of transmission costs are incurred to meet system peak, the existence of DG, which has no impact on peak demand, would be irrelevant to transmission cost incurrence. Brown Affidavit, at p. 47; Martin Affidavit, at p. 8.

62. It is also likely that proliferation of DG will increase not decrease distribution costs. That is because introduction of additional generation sources within the distribution system could change voltage flows in ways that will require more controls, adjustments and maintenance. Additionally, private DG customers will increase transaction costs for utilities including the costs associated with executing interconnection agreements and billing customers for the more complicated transaction that includes tracking both consumption and generation behind customers' meters. Brown Affidavit, at pp. 54-55. DG imposes costs and burdens on the grid by "adding transaction costs and, in many cases, by compelling substantial changes in local networks to reflect the fact that the flow of energy is being changed from one directional to bidirectional. Significant geographic concentration of solar PV may cause the utility to have to make very substantial capital investments to upgrade the grid to accommodate the new flows put on the system. *Id*.

V. A three-part rate design will enable the development of solar as an energy resource over the long-term.

63. A three-part rate will level the playing field for solar and other technology and eliminate cross-subsidies from non-DG to private DG customers. It will reconcile "the interests of solar customers with a set of incentives that drive the efficiency and development of solar technology and that establish a fair and level playing field for solar and other technologies." Brown Affidavit, at p. 57.

64. Currently, the two-part rate structure causes inefficient behavior with respect to installation of private PV systems and the development of new technologies and has prevented the pass-through of reduced costs from PV installers to private DG customers.

65. The current two-part rate structure combined with net metering encourages inefficient installation of PV systems. DG customers with rooftop solar will

> generally receive the most savings by installing south facing panels. This orientation maximizes total kWh produced to take advantage of the retail rate credit, but produces less energy at peak demand hours late in the day (as opposed to panels installed facing west). Thus, a customer who works outside the home and uses air conditioning in the evening during the hot summer months might well offset many (if not all) of his or her kWh of usage through robust rooftop generation. However, such a customer might impose a significant peak demand load on the grid when he or she arrives home at 6 or 7 pm, when solar production is at or near zero, by turning on air conditioning and other electric appliances. In fact, the savings from solar electricity might even encourage such a user to use more peak electricity than he or she otherwise would—keeping the house a little cooler, or otherwise being freer with his or her energy use.

Brown Affidavit, at p. 24. A three-part rate that reflects the cost to the grid of the customer's period of highest demand would encourage customers to install the panels to capture the most sun during peak hours, which would often mean aligning the panels to face the west, "generating less total energy, but capturing the late afternoon power of the setting sun." Brown Affidavit, at p. 30.

66. The current rate structure also discourages the adoption of batteries or other forms of storage in conjunction with private rooftop solar. This is because under the two-part rate structure combined with net metering, the utility "operates essentially as a giant free virtual battery available for use by DG solar customers. Any excess energy DG solar customers produce is credited at the full retail rate, and such customers can import an equivalent amount of energy back from the grid at any time at no charge." Brown Affidavit, at p. 30. This arrangement with the utility is "netted out at the end of the billing cycle without regard to the real time economics of the market. The end result is not reflective of either actual costs or market realities." Brown Affidavit, at pp. 30-31.

67. What this means is that private DG customers, who "would seem to be a natural customer base for energy efficiency and/or capacity savings devices or storage batteries available on the market to better align their energy and capacity demand with system costs," have, under the current rate structure, "no incentives to invest in such products, therefore delaying the development of the integrated solar/battery home systems that may be a logical next step for distributed generation." Brown Affidavit, at p. 31.

68. However, a three-part rate with a demand charge would make it in the interest of private DG customers to "invest in technology that will improve the reliability of their energy supply and better serve the energy and capacity needs of the system." Brown Affidavit, at p. 31. This is illustrated by the fact that commercial customers – who are already subject to demand charges – have adopted solar in conjunction with peak shifting and peak shaving technologies. *Id*. at p. 32. These types of technologies, including battery storage and other demand management technology, are marketed by solar companies to commercial customers. *Id*. A three-part rate will "provide proper price signals to customers to promote economic efficiency and equity, to facilitate

the integration of distributed energy resources with the grid, and to stimulate the cost-effective deployment of other innovative technologies such as customer-situated battery storage." Faruqui Affidavit, at p. 26.

69. The current rate structure also seems to be enabling rooftop solar suppliers to withhold the declining cost of solar panels – "which have been quite dramatic in recent years" – from private DG customers. Instead, the benefits of declining panel costs are being retained by solar vendors. Brown Affidavit, at p. 32. The current rate structure combined with net metering shields rooftop solar suppliers from "both robust competition and from cost-based regulation" and removes a "key incentive for rooftop solar installation companies to pass on declining costs to customers." *Id*. at p. 33.

70. The three-part rate incentivizes the use of technology to increase the cost-effectiveness of private rooftop solar – exactly what net metering does not do. Brown Affidavit, at p. 58. It also enables private DG customers to respond to the new rate through "demand flexibility" and continue to save money with rooftop PV systems. However, the savings to private DG customers will reflect real savings to the utility and therefore to other non-DG customers as well. Brown Affidavit, at p. 58. "This is a 'win-win,' no longer a cross-subsidy." *Id*. at 58. The three-part rate structure proposed by Westar will help foster the development of private solar on a more long-term, sustainable basis, eliminating socially regressive cross-subsidies and recognizing private solar resources for the actual value they provide to the system and to other customers.

VI. Conclusion

71. Westar requests that the Commission (1) find that private DG customers should be charged a cost-based rate different from the current two-part rate utilized now because the current rate structure coupled with net metering is not cost-based, creates inequitable subsidies, and

actually deters development of solar as a long-term, sustainable resource, (2) find that a three-part rate with a demand charge is an appropriate, reasonable, and cost-based rate for private DG customers, (3) find that the alleged benefits associated with DG are not quantifiable and do not provide a sufficient basis to retain the status quo rate structure and resulting cross-subsidy for private DG customers, and (4) authorize utilities to implement a three-part rate for private DG customers through a compliance filing at the conclusion of this docket.

Respectfully submitted,

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ATTORNEYS FOR
WESTAR ENERGY, INC.
KANSAS GAS AND ELECTRIC COMPANY

VERIFICATION

STATE OF KANSAS)
) ss.
COUNTY OF DOUGLAS)

Cathryn J. Dinges, being duly sworn upon her oath deposes and says that she is one of the attorneys for Westar Energy, Inc. and Kansas Gas and Electric Company; that she is familiar with the foregoing **Initial Comments**; that the statements therein are true and correct to the best of her knowledge and belief.

Cathryn Dinges
Cathryn J. Dinges

SUBSCRIBED AND SWORN to before me this 17th day of March, 2017.

Donna G. Quinn
Notary Public

My Appointment Expires: 8/28/2020

Donna G. Quinn
NOTARY PUBLIC—STATE OF KANSAS
MY APPT EXP: 8/28/2020

CERTIFICATE OF SERVICE

I hereby certify that on this 17th day of March, 2017, the foregoing **Initial Comments** were electronically served on all parties of record.

Cathryn Dinges
Cathryn J. Dinges

Affidavit of Dr. Ahmad Faruqui in Kansas Generic Docket on Distributed Generation Rate Design

PREPARED ON BEHALF OF

Westar Energy

March 17, 2016

THE Brattle GROUP

Table of Contents

I. Introduction and Summary

Introduction

I am a Principal with The Brattle Group. I have 40 years of academic, consulting and research experience as an energy economist. During my career, I have advised approximately 135 clients in the energy industry, including utilities, regulatory commissions, government agencies, transmission system operators, private energy companies, equipment manufacturers, and IT companies. In addition to the U.S., my clients have been located in Australia, Canada, Chile, Egypt, Hong Kong, Jamaica, Philippines, Saudi Arabia, South Africa, and Vietnam. I have advised them on a wide range of issues including rate design, load forecasting, demand response, energy efficiency, distributed energy resources, cost-benefit analysis of emerging technologies, integration of retail and wholesale markets, and integrated resource planning. I have testified or appeared before several state, provincial and federal regulatory commissions and legislative bodies. I have been an invited speaker at major energy conferences in Africa, Asia, Australia, Europe, North America and South America. Finally, I have authored, co-authored or co-edited more than 150 articles, books, editorials, papers and reports on various facets of energy economics.

I previously filed testimony on behalf of Westar Energy before the Kansas Corporation Commission (KCC) in Docket No. 15-WSEE-115-RTS regarding a proposal to modify the residential rate design. More details regarding my professional background and experience are set forth in my Statement of Qualifications, included in Appendix A.

Purpose

The purpose of my affidavit is to comment on Westar's proposed rate for residential customers with distributed generation (DG), specifically those with rooftop solar photovoltaic (PV) systems.[1] I begin by discussing the problems with Westar's current rate for DG customers. I then describe how introducing a three-part rate such as the one being proposed by Westar for these customers will address these problems. I conclude with a discussion of several important issues that arise when considering a three-part rate.

Summary

DG customers rely heavily on the power grid. When the sun is not shining or the wind is not blowing, they are drawing power from the grid, like other consumers. And when the sun is shining or the wind is blowing, they may export electricity to the grid if their power generation

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1 Throughout my affidavit, I refer to customers with rooftop PV systems as DG customers.

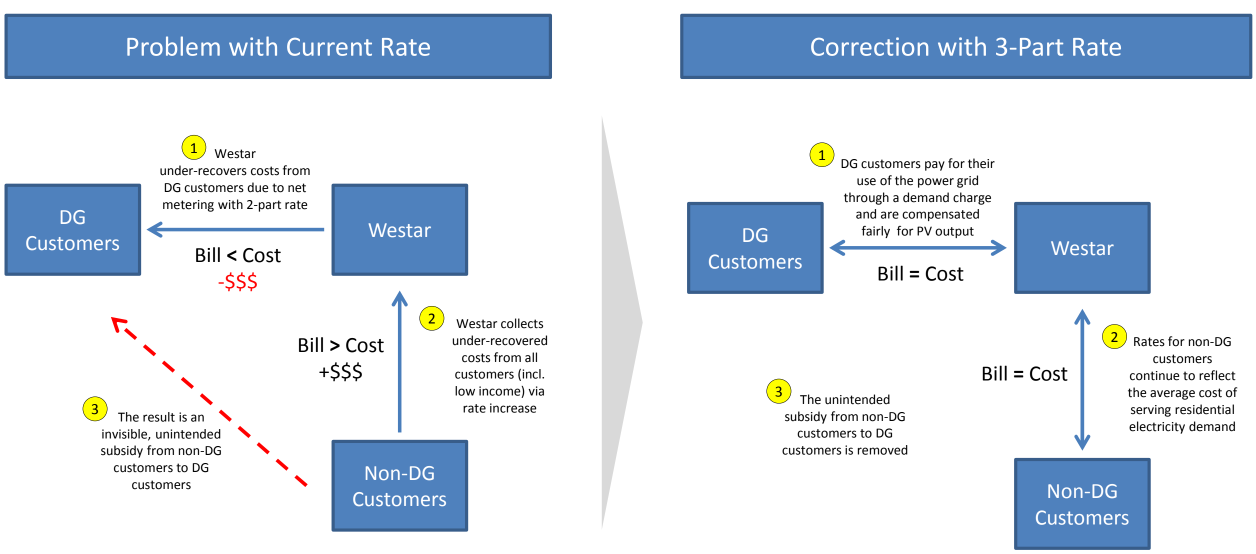
exceeds their power consumption at that time. However, while Westar and the Commission have already defined DG customers under a separate tariff, the rate that Westar currently offers to DG customers is identical to the rate for non-DG residential customers and over-compensates them for the power they sell to the grid. The over-compensation occurs because the residential rate includes not only the variable costs of electricity, which the DG customers are selling to Westar, but also costs associated with the transmission and distribution grid, as well as generation capacity costs and fixed costs of customer service, none of which DG customers are selling to Westar. Further, it does not reflect additional costs that DG customers may impose on the system.

This over-compensation to DG customers means that rates for non-DG customers will be higher than they should be. The result is an invisible and unintended cross-subsidy from non-DG customers (including a disproportionately large share of lower income customers) to DG customers.

This cost-shift can be ameliorated through the introduction of a rate design for DG customers that includes three parts: a fixed charge, a demand charge, and a volumetric charge. This three-part design better aligns the structure of the rate with the underlying structure of costs. It ensures that DG customers will pay their fair share of electricity costs while still being compensated an appropriate amount for the electricity they generate from their solar panels. Since residential DG customers have very different load characteristics than non-DG customers, it is appropriate to consider them a separate class of customers with their own unique rate.

The problem with Westar's current rate, and a description of how this problem can be addressed through the introduction of a three-part rate for DG customers, is provided in Figure 1.

Figure 1: How a Three-Part Rate Corrects the Problem in Westar's Existing Rate



In this affidavit, I elaborate on a number of important points about Westar's proposed three-part rate for residential DG customers. These include:

- The three-part rate that Westar has proposed is consistent with well-established principles for sound rate design, including economic efficiency, equity, revenue adequacy and stability, bill stability, and customer satisfaction.
- Support for three-part rates is found throughout the industry-accepted literature on rate design.
- Three-part rates are a proven concept and have been offered to commercial and industrial customers across the U.S. for decades, as well as to Westar's residential customers (on a limited basis).
- Empirical evidence and reason suggest that customers can understand the concept of demand and will respond to three-part rates by modifying their electricity consumption patterns in economically beneficial ways.
- Demand charges also promote the adoption of beneficial energy technologies like smart thermostats and batteries.
- It is important to compensate DG on a level playing field with other energy resources, and three-part rates promote this equal treatment of resources.

II. The Problems with Westar's Current Rate for DG Customers

DG customers rely heavily on the power grid

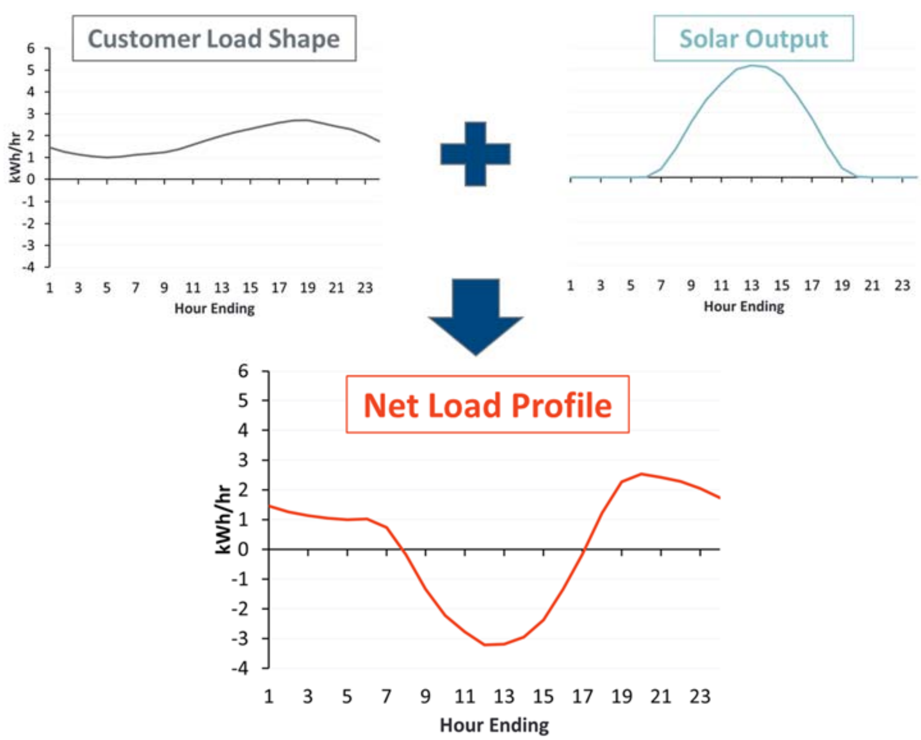
In a discussion of the appropriate rates for DG customers, it is necessary to first understand the way in which DG customers interact with the power grid. There is a common misperception that, by virtue of generating their own electricity, DG customers rely on the power grid significantly less than non-DG customers. In fact, while a customer reduces his/her total energy needs by installing a rooftop PV system, the customer still requires nearly the same amount of power grid infrastructure.

To illustrate, consider a customer who installs a rooftop PV system that is sized to generate the exact same amount of electricity that he or she consumes over the course of the year. That customer is still consuming a significant amount of electricity during hours when the sun is not shining. And when the sun is shining, that illustrative customer will be exporting power to the grid. As a result, he/she still has significant demand during those system peak hours that drive the need for investments in infrastructure that are necessary to maintain a sufficient level of reliability.

The customer has also introduced a new challenge to operators of the power grid – the export of electricity during daytime hours. If PV adoption is geographically clustered, this could lead to new capacity constraints on the distribution system, where transformers are not equipped to handle large amounts of excess generation.

Figure 2 summarizes the impact of DG on the load shape of the Westar residential class average customer during an average summer day. The average customer load profile is derived from Westar's load research sample and the solar PV output profile is from the National Renewable Energy Laboratory's (NREL's) System Advisory Model (SAM) database and is specific to Westar's service territory.[2] While the customer generates as much electricity as he/she consumes over the course of the year, he/she still has demand during system peak hours, and therefore requires generation and transmission capacity. Further, the customer's own maximum demand, a measure which is often considered when determining distribution costs, is reduced by only around five percent. In this example, the customer exports approximately 7,200 kWh to the grid over the course of the year during hours when the customer was not able to consume all of the generated electricity on-site. The customer's maximum net export level reaches 6.2 kW, relative to a maximum demand of only 3.6 kW.

Figure 2: Residential Customer Load Profile, Average Summer Day



Notes: Solar data based on Wichita, KS. Load data based on Westar's 2013 residential load research sample. Based on illustrative assumption that the solar PV installation exactly offsets the customer's annual electricity consumption.

It is worth noting that the solar profile shown in Figure 2 is averaged over many days and based on typical weather data. On any given individual day, and with more temporal granularity in the chart, the profile would show spikes and dips. These fluctuations would need to be addressed

[2] More information about NREL's SAM can be found here: https://sam.nrel.gov

to some degree through the procurement of balancing services from flexible sources of generation or demand response.

Westar's current rate design under-recovers costs from DG customers

The core problem with Westar's current rate design is that the structure of the rate does not align well with the nature of the utility's underlying costs. As a result of this misalignment, DG customers do not pay for their full use of the power system.

As a result of Westar's 2015 rate review, Westar and the Commission have taken an important first step in modernizing residential rate design. Westar now has separate tariffs for residential non-DG customers and residential DG customers. However, these tariffs are currently identical in design. The current rate design is a two-part rate with a $14.50/month fixed charge and a variable charge that is, on average, around 12 cents/kWh over the course of the year.[3] In contrast, Westar's truly variable costs – fuel and variable O&M - account for only a modest fraction of the variable rate. The remainder of the costs are largely either (1) customer costs, such as metering and billing, that are fixed on a dollars-per-customer basis, or (2) investments in generation, transmission, and distribution capacity which are sunk costs that are driven mostly by a combination of fixed and demand-related measures. This misalignment between Westar's costs and rates is illustrated in Figure 3, which shows the charges and costs behind the monthly bill of an average residential customer.[4]

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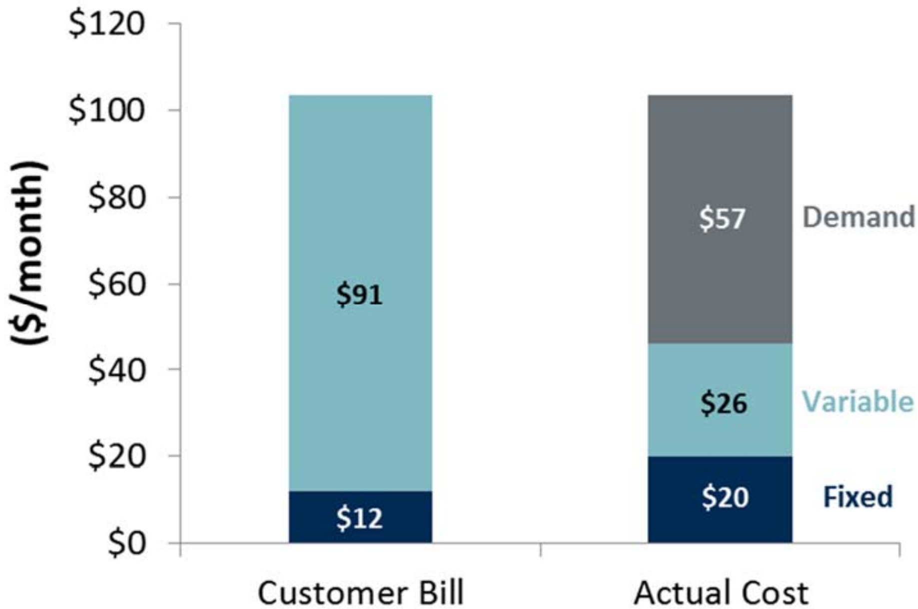
[3] The design is an inclining block rate in the summer and a declining block rate in the winter. It also includes flat charges for riders such as the energy efficiency rider (EER), and transmission delivery charge (TDC). I have presented the average flat rate, as determined by dividing total revenue from all variable charges by the associated billing determinant, which are residential kWh sales.

[4] To calculate the customer bill, I relied on Westar's 2015 residential revenue collection data and divided by the total number of residential customers served. To calculate the actual costs incurred by Westar, I used the breakdown of costs between demand, energy, and customer components from Westar's 2015 class cost of service study along with the consumption profiles in Westar's load research sample. Figures may not sum due to rounding.

Figure 3: Misalignment between Charges and Costs in Typical Residential Bill



Notes: Based on 2015 Westar revenue data. Westar's customer charge was $12/month at the time, but has since increased to $14.50/month. Revenue estimates exclude a small amount of revenue from the demand charge (0.4% of total residential revenue) in the Peak Management rate, which is not open to new enrollment.

As a result of this misalignment, DG customers underpay for their use of the power grid. Consider the previously discussed example of the customer who installed a PV system. In a month when that customer's generation equals or exceeds his/her consumption, he/she pays only the monthly customer charge, which is currently $14.50 (it was $12 in the year of the data behind Figure 3). Westar, however, incurs a cost of approximately $77 to serve that customer in that month, saving only on fuel and variable O&M costs, as well as potentially on line losses.[5] The affidavit of Ashley Brown discusses the potential benefits of rooftop PV in more detail.[6]

In the long run, the customer's reduction in peak demand might help Westar save on investments in new generation, transmission, and distribution capacity. But since there is low coincidence between the output of the rooftop PV system and the timing of the system peak, the cost savings are likely to be modest. Assuming that the customer's reduction in demand during system peak hours would reduce his/her contribution to generation, transmission, and

5 $77 is the sum of the fixed and demand-related costs. The cost of energy to serve the customer during hours when the sun is not shining could be considered an additional cost to be added to this total.

6 Ashley C. Brown Affidavit in Kansas Generic Docket on Distributed Generation Rate Design, March 17th 2017.

distribution capacity costs by that same percentage (an assumption which likely overstates the possible cost savings)[7], the customer's peak demand reduction would translate into avoided capacity costs of around $19.50 /month.[8] **This still leaves a deficit of $43/month in costs that are not recovered from the customer through the monthly bill.**[9] Further, as I discuss later in my affidavit, the customer's use of rooftop PV could impose additional costs on the system.

The under-recovery of costs from DG customers means other customer bills will increase

Under the current regime in which DG and non-DG residential customers pay the same rates, the shortfall in revenue associated with DG customers means that residential rates will need to be increased in order to fully recover the costs of the power grid. As a result, non-DG customers will pay for both their use of the power grid as well as that of the DG customers' use of the power grid, to the extent the DG customers are not contributing to their fair share of the grid costs because of the nature of the current two-part rate design that applies to all residential customers today.

The extent of this unintended cross-subsidy will depend on a number of factors, such as the number of customers adopting PV, the average size of PV installation, and the rate structure and level. A survey of studies in other jurisdictions designed to quantify the magnitude of this cost shift found that it could amount to between approximately $400 and $1,800 per DG customer per year.[10] This is summarized in Figure 4, with supporting details in Appendix B. While the magnitude of the subsidy in Westar's service territory may differ from these estimates due to differences in customer and cost characteristics across utilities, there is little doubt that such a subsidy exists under the current rate structure.

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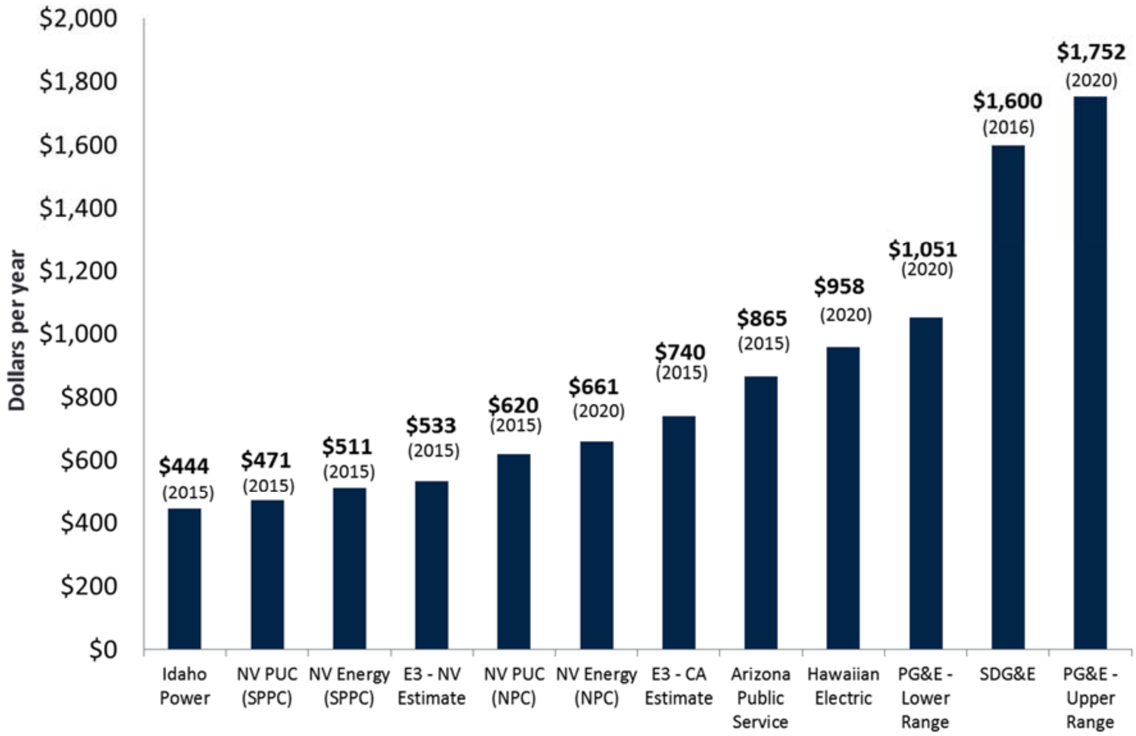
7 This assumption likely overstates cost savings for a number of reasons. For instance, investments in generation and transmission are increasingly being driven by factors other than peak demand (e.g., renewables integration) so a reduction in peak demand does not translate into a one-for-one reduction in capacity. Also, at significant levels of adoption the peak will simply shift to later hours of the day, limiting the amount of peak reduction that can be achieved through PV generation.

8 Avoided G&T costs are calculated by multiplying solar PV's capacity value (34%) by the demand portion of the costs an average residential customer contributes to Westar's system ($57). To determine the capacity value, I calculated the average kW reduction in load during the top 100 load hours resulting from the installation of a kW of solar.

9 The deficit of $43 is equal to the total bill amount of $103 minus avoided variable costs ($26), avoided capacity costs ($19.50), and the revenue collected through the customer charge ($14.50 under the current rate design).

10 For further discussion of the cost shift studies, see Barbara Alexander, Ashley Brown, and Ahmad Faruqui, "Rethinking Rationale for Net Metering," *Public Utilities Fortnightly*, October 2016.

Figure 4: Rooftop PV Cost-Shift Estimates ($ per PV customer per year)



Notes: Year indicates date of cost-shift estimate, which is sometimes a forecast. In some cases, reported estimates were converted to annual dollars per NEM customer for comparison purposes. The PG&E ranges are calculated using assumptions from the California Public Utilities Commission's Public Modeling Tool. PPC and NPC refer to Sierra Pacific Power Company and Nevada Power Company service territories respectively.

A troubling aspect of this problem from a policy standpoint is the observation that low income customers will be hit disproportionately hard by this unintended cross-subsidy. That is because low income customers are less likely to have DG than other customers. A customer needs to have either accumulated enough savings to pay for the investment in the PV system up-front, or he/she needs to have a credit history that is good enough to qualify for a solar leasing program. Low income customers are typically at a disadvantage in both regards.

Research supports the observation that low income customers bear a disproportionate share of the cost shift burden. Publicly available studies by E3[11] (for the California Public Utilities Commission), Dr. Severin Borenstein[12] (a professor at UC Berkeley), and Solar Pulse[13] (a solar

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11 E3, "Introduction to the California Net Energy Metering Ratepayer Impacts Evaluation," Report prepared for the California Public Utilities Commission, October 2013.

12 Severin Borenstein, "Private Net Benefits of Residential Solar PV: The Role of Electricity Tariffs, Tax Incentives and Rebates," Haas Energy Institute Working Paper, July 2015.

market research firm which pairs customers with rooftop PV installers) have all shown empirically that lower income customers have been less likely to install rooftop PV than higher income customers. Table 1 summarizes the conclusions of each study.

Table 1: The Relationship between Household Income and Rooftop PV Adoption

Study	Key Findings
E3 / CPUC (2013)	Using data for 115,000 DG customers in California, the study found that **the median income of DG customers was 34% ($23k/year) higher than that of all utility customers**. The study relied on U.S. Census income data at the Census tract level and utility customer data.
Borenstein / UC Berkeley (2015)	Using Census tract-level income data and utility data to estimate individual household incomes, the study examines the income distribution of solar adopters and how that has changed over time. The study finds that "**the skew to wealthy households adopting solar is still significant**, but has lessened since 2011."
Solar Pulse (2016)	Using household-level data for 11,000 households, the study found that "expensive homes and wealthy homeowners are much more likely to have solar panels." While the study suggests that the income gap is narrowing, it finds that **the average household income of a DG customer was $117k, compared to an average annual income of $87k** for the average household in the sample.

Inefficient adoption of PV could also impose new costs on the system

In addition to the issue of under-recovery of fixed costs, it is also possible that significant adoption of PV will impose new costs on the power system. There are at least two ways in which this could happen. The first, as I described earlier, is the possibility that clustered adoption of PVs will lead to increased distribution capacity costs, as the grid is upgraded to handle large amounts of output from distributed PV systems.

The second category of new costs is what I refer to as grid reliability costs. This includes an increase in flexibility in the power system that will be needed to respond to the intermittent and non-dispatchable nature of solar PV. For instance, a commonly cited concern in California, which has aggressive renewable adoption goals, is the amount of "ramping" capacity that will be

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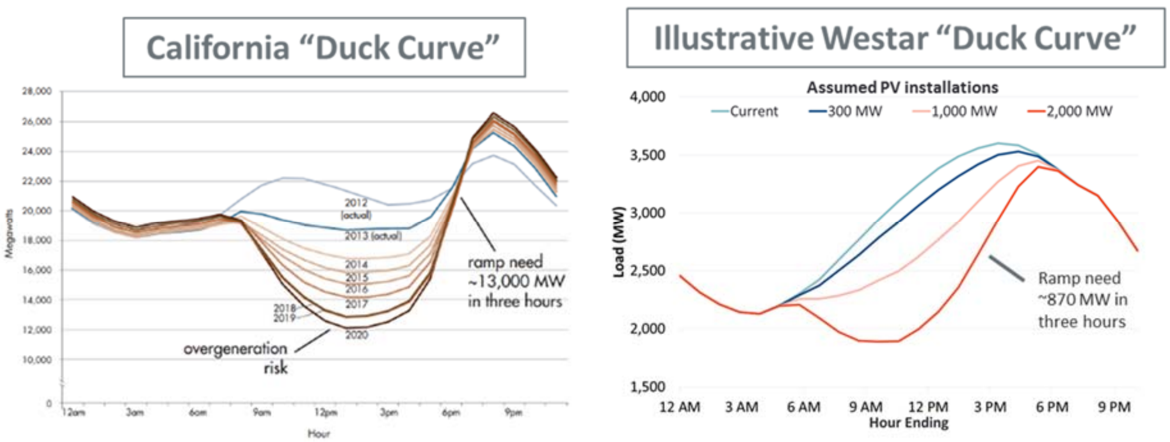
Continued from previous page

[13] Solar Pulse Staff, "Is Going Solar Just for Wealthy People?" July 2016, accessed online October 2016.

needed to meet electricity demand as the sun sets in the evening. This coincides with residential customers returning home in the evening, turning on their appliances and ramping up their air-conditioners. The net system peak demand simply shifts to later in the evening and the power system has to be equipped to handle an increase in net demand of hundreds or thousands of megawatts over the course of one hour.

An illustration of the "duck curve" phenomenon is provided in Figure 5 using Kansas system load and solar profile data.[14] The chart illustrates the change in system load shape that would occur at various levels of PV installation. It is not intended to be a forecast of PV adoption in Westar's service territory. For comparison purposes, it is shown next to the California curve, which is similar in shape. Note that the "duck curve" could be driven by investments in all types of solar, including both distributed and utility-scale resources.

Figure 5: The California and Westar "Duck Curves"



It should be noted that these costs are likely to emerge only at significant levels of PV market penetration, when the impact on the grid is large enough to significantly alter planning and operation activities. A study would need to be performed to determine exactly what that threshold level of market penetration is.

Residential DG customers have very different characteristics than non-DG customers

Residential DG customers are distinctly different than non-DG customers. As I discussed above, DG customers export electricity to the grid at times and import electricity at other times. As a result, their net load profile looks very different from that of non-DG customers and their cost profiles are similarly different. These differences are significant enough to warrant the creation

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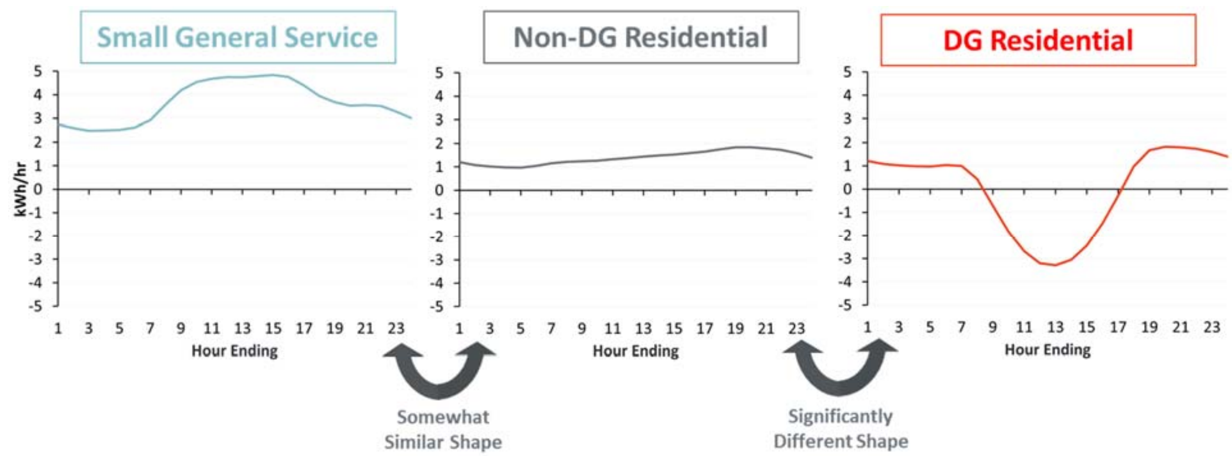
14 The chart shows the impact of various solar PV installation levels on the 2013 Westar average system load shape across all summer days. It is simply intended to illustrate the integration challenges associated with growing levels of non-dispatchable generation. It is not a forecast.

of a separate customer class with a different rate structure for those customers who elect to serve a portion of their own energy needs.[15]

Consider, for instance, the difference between residential and Small General Service (SGS) customers. While many of the small SGS customers are connected to the distribution system at the same level as residential customers and can have demand that is of a similar magnitude, differences in their electricity consumption patterns are enough to warrant a different rate class. These differences pale in comparison to the difference between residential DG and non-DG customers. A comparison of load profiles for these three customer groups is shown in Figure 6.

Figure 6: Average Daily Load Profiles



Notes: DG net load calculated using NREL SAM data. Load profiles are annual averages.

If differences in the load shape between SGS and Residential customers warrant the creation of different rate classes, differences between residential DG and non-DG customers should similarly warrant the creation of a new class of DG customers. There are many parallels to this concept at utilities in other jurisdictions, where separate rates are created for customers with electric space heating or electric vehicles, for example.

15 Note that this would not apply to some cases, such as a buy-all/sell-all arrangement. Under that arrangement, the customer pays the full cost of his/her load under the existing rate which is designed to recover those costs, and is separately compensated for the value of his/her DG output.

III. The Benefits of Three-Part Rates

The introduction of three-part rates will help to address these problems

To address the deficiencies of Westar's current two-part rate, I support the institution of a three-part rate design. A three-part rate consists of a fixed monthly service charge, a demand charge, and a volumetric charge.

The fixed charge should be designed to cover the fixed costs such as metering, billing, and customer care. Sometimes it also covers the cost of the line drop and the associated transformer.

The demand charge should be designed to cover demand-driven costs, such as distribution, transmission, and generation capacity. It is typically applied to the individual customer's maximum demand, either during a defined on-peak period, or regardless of time of occurrence, or based on a combination of the two. While the concept of demand is instantaneous, in implementation demand is usually measured over 15-minute, 30-minute or 60-minute intervals.

The energy charge covers the cost of the fuels that are used to generate electricity, some variable environmental compliance costs, and power grid operations and maintenance (O&M). The demand charge and the energy charge might vary with the time of use of electricity and have different seasonal and/or peak/off-peak charges. Such three-part rates align the rate design with costs, a fundamental tenet of rate design.

By aligning the structure of the rate with the costs that it is intended to reflect, the unintentional shift in cost recovery from DG to non-DG customers will be ameliorated. With this new rate design, DG customers will be fairly compensated for the value of their output to the power grid and the subsidy from non-DG customers will be reduced or eliminated. A more cost-reflective rate will also encourage the adoption of emerging energy technologies and changes in energy consumption behavior that will lead to more efficient use of power grid infrastructure and resources.

Support for three-part rates is found throughout the literature on rate design

The principles that guide rate design and support the deployment of three-part rates have evolved over time. Many authorities have contributed to their development, beginning with the legendary British rate engineer John Hopkinson in the late 1800s.[16] Hopkinson introduced demand charges into electricity rates. Not long after, Henry L. Doherty proposed a three-part

[16] John R. Hopkinson, "On the Cost of Electricity Supply," Transactions of the Junior Engineering Society, Vol. 3, No. 1 (1892), pp.1-14.

tariff, consisting of a fixed service charge, a demand charge and an energy charge.[17] The demand charge was based on the maximum level of demand which occurred during the billing period. Some versions of the three-part tariff also feature seasonal or time-of-use (TOU) variation corresponding to the variations in the costs of energy supply.[18]

In the decades that followed, a number of British, French and U.S. economists and engineers made further enhancements to the original three-part rate design.[19] In 1961, Professor James C. Bonbright coalesced their thinking in his canon, Principles of Public Utility Rates,[20] which was expanded in its second edition by two co-authors, Albert Danielsen and David Kamerschen, and published in 1988. Some of these ideas were further expanded upon by Professor Alfred Kahn in his treatise, The Economics of Regulation.[21]

There are well-established principles for sound rate design

In the first edition of his text, Bonbright propounded eight principles which were expanded into ten principles in the second edition. These are almost universally cited in rate proceedings throughout the U.S. and are often used as a foundation for designing rates. For ease of exposition, I have grouped these into five core principles:

1. <u>Economic Efficiency.</u> The price of electricity should convey to the customer the cost of producing it, ensuring that resources consumed in the production and delivery of electricity are not wasted. If the price is set equal to the cost of providing a kWh, customers who value the kWh more than the cost of producing it will use the kWh and customers who value the kWh less will not. This will encourage the development and adoption of energy technologies that are capable of providing the most valuable services to the power grid, and thus the greatest benefit to electric customers as a whole.

2. <u>Equity.</u> There should be no unintentional subsidies between customer types. A classic example of the violation of this principle occurs under flat rate pricing structures (*i.e.*,

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17 Henry L. Doherty, Equitable, Uniform and Competitive Rates, Proceedings of the National Electric Light Association (1900), pp.291-321.

18 See, for example, Michael Veall, "Industrial Electricity Demand and the Hopkinson Rate: An Application of the Extreme Value Distribution," Bell Journal of Economics, Vol. 14, Issue No. 2 (1983).

19 The most notable names include Maurice Allais, Marcel Boiteux, Douglas J. Bolton, Ronald Coase, Jules Dupuit, Harold Hotelling, Henrik Houthakker, W. Arthur Lewis, I. M. D. Little, James Meade, Peter Steiner and Ralph Turvey.

20 James C. Bonbright, Albert L. Danielsen, and David R. Kamerschen, Principles of Public Utility Rates, 2d ed. (Arlington, VA: Public Utility Reports, 1988).

21 Alfred Kahn, The Economics of Regulation: Principles and Institutions, rev. ed. (MIT Press, June 1988).

cents/kWh). Since customers have different load profiles, "peaky" customers, who use more electricity when it is most expensive, are subsidized by less "peaky" customers who overpay for cheaper off-peak electricity. Note that equity is not the same as social justice, which is related to inequities in socioeconomic status rather than cost. The pursuit of one is not necessarily the pursuit of the other, and vice versa.

3. <u>Revenue adequacy and stability.</u> Rates should recover the authorized revenues of the utility and should promote revenue stability. Theoretically, all rate designs can be implemented to be revenue neutral within a class, but this would require perfect foresight of the future. Changing technologies and customer behaviors make load forecasting more difficult and increase the risk of the utility either under-recovering or over-recovering costs when rates are not cost reflective.

4. <u>Bill stability.</u> Customer bills should be stable and predictable while striking a balance with the other ratemaking principles. Rates that are not cost reflective will tend to be less stable over time, since both costs and loads are changing over time. For example, if fixed infrastructure costs are spread over a certain number of kWh's in Year 1, and the number of kWh's halves in Year 2, then the price per kWh in Year 2 will double even though there is no change in the underlying infrastructure cost of the utility.

5. <u>Customer satisfaction.</u> Rates should enhance customer satisfaction. Because most residential customers devote relatively little time to reading their electric bills, rates need to be relatively simple so that customers can understand them and perhaps respond to the rates by modifying their energy use patterns. Giving customers meaningful cost-reflective rate choices helps enhance customer satisfaction.

The overriding principle in rate design is that of cost-causation. In other words, the rate structure should reflect the underlying cost structure. The importance of economic efficiency – and specifically on designing rates that reflect costs – is emphasized by Bonbright. In the first edition of his text, Bonbright devotes an entire chapter to cost causation. In the chapter, he states: "One standard of reasonable rates can fairly be said to outrank all others in the importance attached to it by experts and public opinion alike – the standard of cost of service, often qualified by the stipulation that the relevant cost is necessary cost or cost reasonably or prudently incurred."[22] Later, he states "The first support for the cost-price standard is concerned with the consumer-rationing function when performed under the principle of consumer sovereignty."[23] Bonbright also cites another benefit of the cost-price standard, saying that "an individual with a given income who decides to draw upon the producer, and hence on society, for a supply of

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22 James C. Bonbright, *Principles of Public Utility Rates*, (Columbia University Press: 1961) 1st Edition, Chapter IV, p. 67.

23 Op. cit., p. 69.

public utility services should be made to 'account' for this draft by the surrender of a cost-equivalent opportunity to use his cash income for the purchase of other things."[24]

Westar's proposed three-part rate is consistent with these established rate design principles

Westar has proposed to introduce a three-part rate for DG customers to address the previously described issues with the current rate design. While Westar is proposing to develop the specific rate details in a future proceeding, they have established some basic attributes of the proposed rate design. Those attributes include a modest fixed charge, a flat year-round volumetric charge, and a seasonally differentiated demand charge. Demand is based on the customer's maximum demand at any point in the billing cycle. Until there is more detailed data on DG customer energy profiles, the rate would be designed to be revenue neutral for the residential class as a whole, meaning that it would collect the same revenue as the current rate for the average non-DG residential customer.

These rate design characteristics are consistent with the three-part rate that was proposed by Westar in its 2015 General Rate Case. To establish an illustrative rate for the analysis in my affidavit, I have relied on a slightly modified version of that previously proposed three-part rate.[25] A comparison of the current rate and the new three-part rate is provided in Table 2 below.

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24 Op. cit., p. 70.

25 The only changes I made to that rate were to (1) modify the customer charge to be consistent with Westar's current residential customer charge, and (2) to adjust the volumetric charge to continue to maintain revenue neutrality for the class as a whole.

Table 2: Westar's Current and Proposed DG Rates

Existing Rate		
Customer Charge	$	14.50
1st 900 kWh	$	0.075360
All Additional kWh (Winter)	$	0.061600
All Additional kWh (Summer)	$	0.083127
Proposed Three-Part Rate		
Customer Charge	$	14.50
Energy / kWh	$	0.042266
Demand / kW (Winter)	$	3.00
Demand / kW (Summer)	$	10.00
Riders (per kWh) - Applied to All Rates		
RECA	$	0.020114
TDC	$	0.016997
ECRR	$	-
PTS	$	0.000895
EER	$	0.000199

Note: ECRR is accounted for in the energy charge of the proposed rates. Net excess generation is assumed to be credited at 2.2 cents/kWh based on review of historical Westar data. The energy charge in the proposed three-part rate has been adjusted using the load research sample provided by Westar to maintain revenue neutrality.

Westar's proposed three-part rate design is consistent with the five principles of rate design described above.

Regarding economic efficiency, the cost-based price signals in the three-part rates proposed by Westar provide customers with the financial incentive to make investments in technologies or otherwise change their behavior in ways that are most beneficial to the system. Technologies and behaviors that reduce a customer's demand should ultimately lead to a more efficient use of the grid, reduced costs, and lower bills.

The proposed rate is also equitable. Each customer imposes costs on the system, some of which are fixed and the rest of which are demand-driven and energy-driven. Under purely volumetric tariffs, customers with high demand but low monthly consumption (such as DG customers) would not be paying their fair share of the cost of maintaining, upgrading, and expanding the utility's generation, transmission and distribution system. Instead, lower-demand customers would be covering the deficit and paying more than their fair share. Each of Westar's proposed three-part rates more closely match demand, fixed, and variable costs with demand, fixed, and variable charges and will reduce this inequity so that all customers will pay their fair share of the costs associated with the generation of electricity, its delivery through utility's transmission and distribution system, and customer service.

In terms of customer satisfaction, while the new rate would increase bills for DG customers in the absence of any change in consumption patterns, I believe DG customers are likely to find it more attractive than other meaningful options for addressing the problems in the current rate, such increasing the fixed monthly charge. With a three-part rate, customers have the ability to reduce their bills by managing their electricity demand; it provides them with an option that other rate designs do not.

The proposed three-part rate also satisfies the principle of bill stability. Westar's current rates recover significant amounts of fixed costs through volumetric charges. The result is an overstated volumetric charge. This subjects a disproportionate amount of a customer's bill to month-to-month fluctuations in usage, and as a result, bills are more variable and unpredictable than they would be if the rates were designed more appropriately. In a variable climate like Kansas, this can result in high seasonal bills relative to other times of the year. A common misperception is that demand charges will increase bill volatility. In fact, a recent study with a sample of residential customers in Vermont found that bill volatility would decrease for a majority of customers with the introduction of a demand charge, relative to a two-part rate with a high volumetric charge.[26]

Finally, the proposed rate satisfies the criterion of revenue stability. The rate will not change Westar's revenues. Rather, it more accurately collects revenue from those customers who are imposing costs on the power system. It is worth noting that, while Professor Bonbright says that rates should be stable and predictable, he does not say that rate structures should remain frozen in time. In the U.S., there is an ineluctable movement towards cost-reflective rates brought about by the rollout of advanced metering infrastructure (AMI) and by the increased availability and customer adoption of a wide range of digital end-use technologies such as smart appliances, smart thermostats, home energy management systems, battery storage systems, electric vehicles and rooftop solar panels. Westar's three-part rate proposal is designed to provide stability in this new environment.

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26 Ryan Hledik and Gus Greenstein, "The Distributional Impacts of Demand Charges," *The Electricity Journal*, July 2016, page 37.

IV. Important Considerations with Three-Part Rates

Three-part rates are a proven concept

There is extensive industry experience with three-part rates. They have been offered to commercial and industrial (C&I) customers for decades, and could be considered the norm for these customer classes. In Kansas, demand charges are offered by all major utilities.[27] In fact, all of these utilities offer three-part rates to at least a portion of the C&I customers on a mandatory basis.[28] Five of the utilities offer demand charges on a mandatory basis to even the smallest commercial and industrial customer segment.

Three-part rates are also currently offered by utilities to residential customers, though on a more limited basis. Their availability is increasing in part as technical barriers are removed through the deployment of AMI. There are at least 30 utilities in 17 states that offer a three-part rate to residential customers.[29] Three of these utilities are in Kansas, including Westar's Peak Management rate.[30] Arizona Public Service (APS) has the most highly subscribed residential three-part rate in the US, with nearly 120,000 of its customers enrolled, and APS has proposed to make three-part rates the standard rate for all residential customers. Similar to Westar's proposal, Salt River Project (SRP) recently instituted a mandatory three-part rate for all residential customers who chose to install a new grid-connected distributed generation (DG) photovoltaic system after January 1, 2015.[31,32] Mid-Carolina Electric Cooperative (South Carolina) and Butler Rural Electric Cooperative (Kansas) include demand charges as a mandatory feature of their residential rate offerings to all customers.

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27 For relevance, I excluded small utilities serving less than 10,000 customers. There are 12 utilities in Kansas above this size threshold. The list includes investor-owned utilities, cooperatives, and public utilities. See Appendix C for details.

28 This is also common practice at many utilities throughout the US.

29 The Brattle Group survey was conducted in June 2016. A list of utilities is provided in Appendix D.

30 At its peak enrollment, the rate had 15,600 participants. My understanding is that there were 6,597 customers on the rate as of December 2016, because it has not been open to new enrollment for several years and attrition has occurred as customers have left the service territory. The other Kansas utilities are Midwest Energy and Butler Rural Electric Cooperative.

31 SRP website. http://www.srpnet.com/prices/home/customergenerated.aspx.

32 Peak demand management could be another driver. Although many three-part rates are driven by DG, it is not the only motivation behind the rate. In Maryland and Missouri where utilities' ability to design rates specifically for DG is restricted, the focus is on the demand management benefit.

Customers can understand the concept of demand

Some have opined that three-part rates should not be offered to residential customers since customers will not be able to comprehend the very notion of a demand charge. However, there are good reasons to believe that residential customers can and will understand electricity demand once it is explained to them properly. This is particularly true for DG customers who, by adopting rooftop PV and generating their own electricity, have already demonstrated clear engagement in their energy usage beyond that of the average customer.

DG customers are likely familiar with the concept of demand, because the size of their installation was probably expressed to them in kilowatts of installed capacity, not just kWh of output. Demand rates for rooftop PV customers, therefore, would convey prices in terms and units with which they are likely to be already familiar.

There is a logical disconnect in suggesting that the same DG customers who are capable of understanding the complexity of 20-year rooftop solar leases could not understand the concept of demand charges. Understanding the economics of a rooftop solar lease would involve projecting future utility bill increases or decreases, lease rates, the impact on home resale value, maintenance, lease cancellation penalties, and other factors. Yet customers have made the decision to agree to these terms. Conceptually, it is difficult to understand why DG customers would be able to deal with this complexity but not with the notion of a simple demand charge. The same applies to customers who purchase the PV systems outright.

Just about every customer, including DG customers, would have encountered the concept of electricity demand in daily life. Take the case of the ubiquitous light bulb. When buying or installing a light bulb, the customer had to choose a bulb that would project a certain amount of light. It was then that the customer would have encountered the power of the bulb expressed in watts. The wattage would have been expressed as 40 watts, 60 watts, 75 watts or 100 watts (or their equivalent, if the bulb was a compact fluorescent or LED bulb). The customer would have picked the bulb based on its wattage, with the higher wattage translating into more "power." Given that wattage is exactly how demand is measured, it would be difficult to find a customer who has not encountered the concept of demand.

Further, if the customer had purchased a high-wattage hair dryer and a high-wattage electric iron, and decided to run both at the same time, they may have tripped the circuit breaker, requiring a visit to the garage or basement to reset it. This is not an uncommon experience, and is another way in which customers would have become familiar by experience with the concept of demand or capacity.

Finally, anyone who has bought a pump or a motor for domestic use has encountered the concept of horsepower. That is another measure of demand and is related mathematically to kilowatts.

Customers do not need to know the precise definition of a kilowatt in order to be able to respond to a three-part rate. Successful education would involve conveying simple messages about actions that customers can understand and relate to. For instance, APS's marketing material includes the statement "stagger the use of major appliances (air conditioner, electric water heater, dryer, oven) during on-peak hours. The more you stagger, the more you save on the demand component."[33] Encouraging customers to stagger their use of electricity-intensive appliances would facilitate demand reductions without even using the word "kilowatt."

In addition, there is empirical evidence that customers will respond to demand charges by changing their electricity consumption patterns. This suggests that customers can understand demand charges. I provide further discussion on this point below.

Customers can respond to three-part rates

Three-part rates will incentivize customers to smooth their energy consumption profile – and therefore reduce their electricity bills. There is a widespread misperception that customers do not respond to changing electricity prices. This is contradicted by empirical evidence derived from more than 50 pilots and full-scale rate deployments involving over 200 innovative rate offerings over roughly the past dozen years. The pilots have found that customers can and do respond to new price signals by changing their consumption pattern.[34]

Further, there is evidence that customers respond not just to changes in the rate structure generally, but specifically to demand charges. The following studies arrived at this conclusion after careful empirical analysis:

- Caves, D., Christensen, L., Herriges, J., 1984. "Modeling alternative residential peak-load electricity rate structures." J. Econometrics. Vol 24, Issue 3, 249-268.
- Stokke, A., Doorman, G., Ericson, T., 2009, January. "An Analysis of a Demand Charge Electricity Grid Tariff in the Residential Sector," Discussion Paper 574, Statistics Norway Research Department.
- Taylor, Thomas N., 1982. "Time-of-Day Pricing with a Demand Charge: Three-Year Results for a Summer Peak." Award Papers in Public Utility Economics and Regulation. Institute of Public Utilities, Michigan State University, East Lansing, Michigan.
- Taylor, T., Schwartz, P., 1986, April. "A residential demand charge: evidence from the Duke Power time-of-day pricing experiment." Energy Journal. (2), 135–151.

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33 APS website: https://www.aps.com/en/residential/accountservices/serviceplans/Pages/combined-advantage.aspx.

34 Some of these studies are summarized in Ahmad Faruqui and Sanem Sergici, "Arcturus: International Evidence on Dynamic Pricing," *The Electricity Journal*, (August/September 2013). Similar results were obtained from an earlier generation of 14 pricing pilots that were funded in the late seventies and early eighties by the US Federal Energy Administration (later part of the Department of Energy). See Ahmad Faruqui and Bob Malko, "The Residential Demand for Electricity by Time-of-Use: A Survey of Twelve Experiments with Peak Load Pricing," *Energy*, Vol. 8, No. 10, (1983).

APS has also examined the experience of the customers on its highly subscribed three-part rate and detected a significant level of price response. Specifically, 60 percent of a sample of APS's customers on a three-part rate reduced their demand after switching to the three-part rate, with those who actively manage their demand achieving demand savings of 9 percent to 20 percent or more.[35]

Demand charges can promote adoption of beneficial energy technology

Adoption of enabling technology will further enhance response to demand charges. By providing customers with a price signal that includes a component for demand, a three-part rate would encourage the adoption of technologies that are designed to smooth out a customer's load profile. Behind-the-meter battery storage, for example, could be used to release electricity during hours of high electricity demand and store electricity generated from PV systems during hours of low electricity demand. Load control technologies, such as programmable communicating thermostats, demand limiters, and digital controls built into smart appliances, could also help customers manage their electricity demand. In-home information displays could make customers more aware of their instantaneous demand. Figure 7 provides just a few examples of these technologies.

Figure 7: Examples of Technologies that Facilitate Peak Demand Management

For a PV customer with service under a three-part rate, the use of battery storage or other demand-reducing technologies would reduce the customer's bill. This reduction in the customer's bill is an economic value that forms the basis of the price signal created by three-part rates.

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35 Direct Testimony of Charles A. Miessner, on Behalf of Arizona Public Service Company, In the Matter of Tucson Electric Company, Docket E-01933A-15-0322, June 24, 2016, p. 10.

In the same vein, introducing a demand charge and reducing the volumetric charge for DG customers would decrease the economic attractiveness of energy technologies that cannot provide energy savings during those peak hours when the energy reductions are most valuable to the system. This simply means that the three-part rate structure is encouraging adoption of those technologies that are most beneficial to the power grid and to customers. It is important to take this broader view of energy technologies to avoid overstating the importance of one particular option that may not be the most beneficial.

Westar's proposal will improve fairness in the recovery of costs from DG customers

As I discussed above, the new three-part rate will reduce the unintended subsidy that is being paid by non-DG customers through their rates to DG customers. As a result, bills will likely increase for DG customers under the new rate design and decrease for non-DG customers.

To better understand the potential impact of the three-part rate on DG customers, I simulated the change in bills for a sample of Westar customers whom I assumed had installed rooftop PV. I relied on the same load research sample described earlier and applied the previously discussed NREL solar output profile to all customers in this sample. For simplicity, I assumed that each customer installed a rooftop PV system that supplied 80 percent of his/her annual consumption.[36] My assumption that all customers in the sample install rooftop PV is not intended to imply that all Westar customers have an equal likelihood of installing DG; rather, the assumption is designed to capture the full range of potential impacts on DG customers with varying consumption patterns.

Figure 8 summarizes the resulting change in the average monthly bill for each customer. Percent changes in bills are shown in the left panel and absolute dollar changes in the right panel. In each panel, customers on the left side of the chart experience the smallest bill increase whereas customers on the right side of the chart experience the largest increase. The vast majority of DG customers in the sample would experience a bill increase of less than $40 per month as a result of the introduction of the three-part rate. The median bill increase is in the range of $20 to $30 per month.

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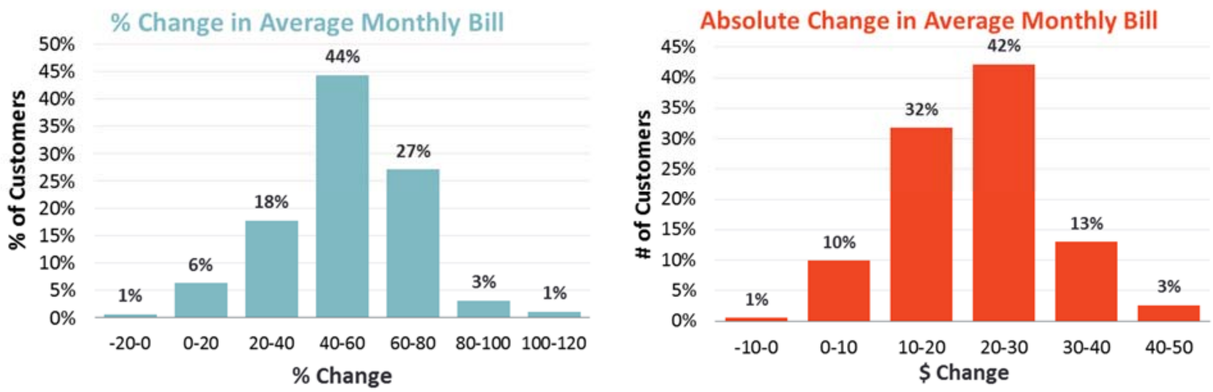
36 This equates to an average installed capacity of 6.6 kW per customer, which is roughly similar in magnitude to the size of installations that Westar has observed in its service territory. This assumption of 80 percent also falls within the general range of estimates that I have seen for residential rooftop solar PV installations in other jurisdictions. See NREL, "Impact of Rate Design Alternatives on Residential Solar Customer Bills: Increased Fixed Charges, Minimum bills and Demand-Based Rates," September 2015. According to the NREL report, the typical rooftop PV installation in the U.S. meets between 61 and 98 percent of the customer's annual energy needs, depending on the state.

Figure 8: Distribution of Bill Changes for DG Customers Due to Introduction of Three-Part Rate

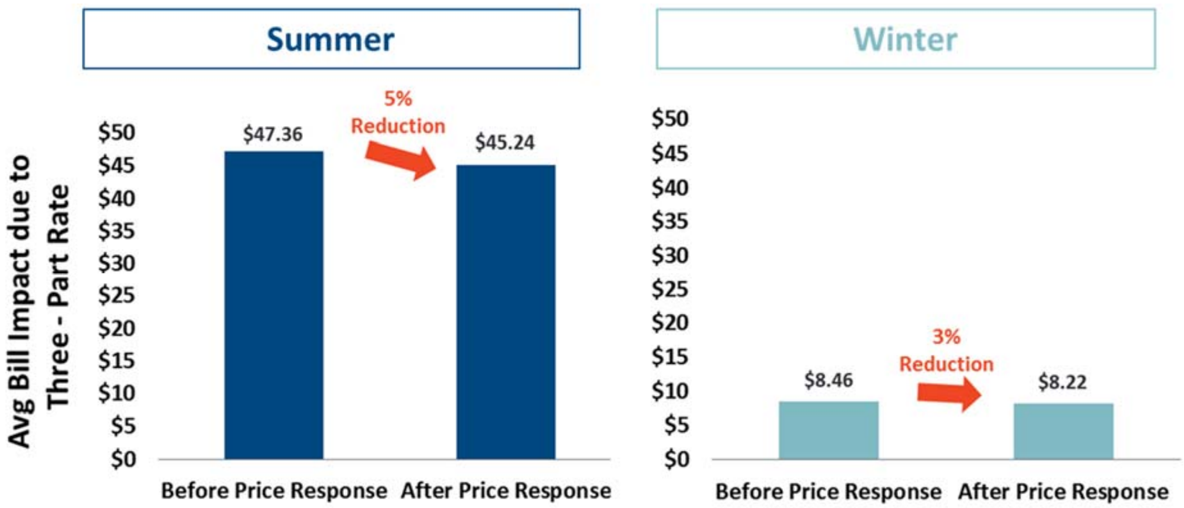


An often overlooked aspect of changes in rate design is the fact that customers will respond to the new price signals by modifying their electricity consumption behavior. These changes will mitigate a portion of the bill increases illustrated in Figure 8. Earlier, I discussed the evidence that customers will respond to demand charges.

Figure 9 shows how customer price response would mitigate the bill increases discussed above. The modeling accounts for the impact of two effects. The first is the "conservation effect," which accounts for the reduction in total consumption that occurs because the customer's cost of electricity increases. This is consistent with the vast literature on price elasticities, which says that when the price of a product goes up, one would buy less of it (*i.e.*, demand curves are downward sloping). The second effect is the "substitution effect." It reflects the shifting of consumption away from higher demand hours to lower-demand hours in order to reduce one's bill (*e.g.*, staggering the use of multiple electricity-intensive appliances like a dishwasher and an oven). Both impacts are commonly observed in customer response to new price signals.[37]

[37] These two effects are commonly incorporated into a system of two demand equations. I have used this modeling framework to estimate peak load reductions in the context of AMI business cases in a variety of jurisdictions including California, Connecticut, Florida, Maryland, and Michigan. I contributed to the development of this two equation system while analyzing California's statewide pricing pilot. See Charles River Associates, "Impact Evaluation of the Statewide Pricing Pilot," March 16, 2005. https://www.smartgrid.gov/files/Impact_Evaluation_California_Statewide_Pricing_Pilot_200501.pdf.

Figure 9: Average DG Customer Bill Change due to Three-Part Rate



Overall, the illustrative analysis suggests that the average monthly bill change for DG customers could decrease by 5% (from $47.36 to $45.24) in the summer and by 3% (from $8.46 to $8.22) in the winter due to price response. The larger reduction in summer bill savings is attributable to a larger response in that season, driven by the higher summer demand charge. This is a positive outcome, because it means that load is being shifted and conserved during the time of year when power system costs are the highest.

Estimates of customer price response are always subject to various forms of uncertainty. To account for this, I have tested a range of estimates of customer price sensitivity. I assumed that DG customers would respond to the new rate with a degree of price responsiveness consistent with observations from recent residential rate design studies in the U.S. My assumptions fall within the range of price elasticities used in a recent study for the KCC.[38] Further detail on the underlying assumptions is provided in Appendix E. In all cases, the bill increase for DG customers lessens after accounting for a realistic level of price response.

It is important to note that my analysis has only accounted for the impact of *behavioral* response to the new rate. If the customers were to adopt enabling technologies that facilitate automated demand reductions, I would expect the impacts to increase and customers to experience significantly larger bill savings. Given emerging interest in "smart home" technologies like

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[38] Christensen Associates Energy Consulting, "Residential Rate Study for the Kansas Corporation Commission," April 11, 2012. http://www.kcc.state.ks.us/electric/residential_rate_study_final_20120411.pdf.

behind-the-meter energy storage or smart thermostats, for example, home automation is likely to play an increasingly important role in managing the bills of DG customers.[39]

It is also important to recognize that the bill increases shown above do not represent an increase in revenues for Westar. The additional revenue collected from DG customers would be offset by bill reductions for non-DG customers. Westar's overall revenues would remain unchanged. Fairness and equity in rate design, however, would improve considerably as a result of this change.

DG should be compensated on a level playing field with other resources

Distributed PV is a clean source of electricity that provides a societal benefit in the form of reduced greenhouse gas emissions. From a policy standpoint, it may be desirable to recognize these environmental benefits of PV and promote its adoption. However, it does not make sense to selectively promote PV adoption through hidden subsidies that are embedded in rates.

If a price has been assigned to a certain externality, essentially internalizing the externality, and that price is part of the utility's cost structure, then it is economically efficient to reflect the price of that externality in rates for all customers. However, it would violate the core principles of ratemaking if only certain customers or technologies were charged or compensated for their impact on those externalities.

For instance, investments in rooftop solar PV that are artificially subsidized through the current rate structure could potentially instead be made in lower cost utility-scale solar or energy efficiency, while achieving many of the same benefits.[40] All technologies and customers should be on a level playing field when developing residential rate design.

V. Conclusion

Westar has put forward a cost-based three-part DG rate proposal that is consistent with the widely-accepted principles of rate design. I support Westar's plan to make this the standard rate for all its residential DG customers. The two-part rate which is presently employed by Westar,

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39 For further discussion, see Mark Dyson et al., "The Economics of Demand Flexibility: How "flexiwatts" create quantifiable value for customers and the grid," Rocky Mountain Institute, August 2015. http://www.rmi.org/electricity_demand_flexibility.

40 A recent Brattle study concluded that customer generation costs per solar MWh are "more than twice as high for residential-scale systems than the equivalent amount of utility-scale PV systems." *See* Bruce Tsuchida *et al.*, Comparative Generation Costs of Utility Scale and Residential-Scale PV in Xcel Energy Colorado's Service Area," prepared for First Solar, July 2015. http://brattle.com/system/publications/pdfs/000/005/188/original/Comparative_Generation_Costs_of_Utility-Scale_and_Residential-Scale_PV_in_Xcel_Energy_Colorado's_Service_Area.pdf.

and through much of the industry, for DG customers is inefficient, inequitable and unsustainable for such customers. It is time to move to three-part rates which would provide proper pricing signals to customers by promoting economic efficiency and equity, facilitating the integration of distributed energy resources with the grid, and stimulating the cost-effective deployment of other innovative technologies such as customer-situated battery storage.

Appendix A: Statement of Qualifications

Dr. Ahmad Faruqui leads a consulting practice focused on understanding and managing the way customers use energy. His clients include utilities, commissions, equipment manufacturers, technology developers, and energy service companies. The practice encompasses a wide range of activities:

- **Rate design.** The recent decline in electricity sales has generated an entire crop of new issues that utilities must address in order to remain profitable. A key issue is the under-recovery of fixed costs and the creation of unsustainable cross-subsidies. To address these issues, we are creating alternative rate designs, testing their impact on customer bills, and sponsoring testimony to have them implemented. We are currently undertaking a large-scale project for a large investor-owned utility to estimate marginal costs, design rates, and produce a related software tool, working in close coordination with their internal executives. We have created a Pricing Roundtable which serves as virtual think tank on addressing the risks of under-recovery in the face of declining growth. About 18 utilities are a part of the think tank.

- **Demand forecasting.** We help utilities to identify the reasons for the slowdown in sales growth, which include utility energy efficiency programs, governmental codes and standards, distributed general, and fuel switching brought on by falling natural gas prices and the weak economic recovery. We present widely on the issue and are researching new methods for forecasting peak demand, such as the use of quantile regression.

- **Demand response.** For several clients in the United States and Canada, we are studying the impact of dynamic pricing. We have completed similar studies for a utility in the Asia-Pacific region and a regulatory body in the Middle East. We also conduct program design studies, impact evaluation studies, and cost-benefit analysis, and design marketing programs to maximize customer enrollment. Clients include utilities, regulators, demand response providers, and technology firms.

- **Energy efficiency.** We are studying the potential role of combined heat and power in enhancing energy efficiency in large commercial and industrial facilities. We are also carrying out analyses of behavioral programs that use social norming to induce change in the usage patterns of households.

- **New product design and cost-benefit analysis of emerging customer-side technologies**. We analyze market opportunities, costs, and benefits for advanced digital meters and associated infrastructure, smart thermostats, in-home displays, and other devices. This includes product design, such as proof-of-concept assessment, and a comparison of the costs and benefits of these new technologies from several vantage points: owners of that technology, other electricity customers, the utility or retail energy provider, and society as a whole.

In each of these areas, the engagements encompass both quantitative and qualitative analysis. Dr. Faruqui's reports, and derivative papers and presentations, are often widely cited in the media. The Brattle Group often sponsors testimony in regulatory proceedings and Dr. Faruqui has testified or appeared before a dozen state and provincial commissions and legislative bodies in the United States and Canada.

Dr. Faruqui's survey of the early experiments with time-of-use pricing in the United States is referenced in Professor Bonbright's treatise on public utilities. He managed the integration of results across the top five of these experiments in what was the first meta-analysis involving innovative pricing. Two of his dynamic experiments have won professional awards, and he was named one of the world's Top 100 experts on the smart grid by Greentech Media.

He has consulted with more than 50 utilities and transmission system operators around the globe and testified or appeared before a dozen state and provincial commissions and legislative bodies in the United States and Canada. He has also advised the Alberta Utilities Commission, the Edison Electric Institute, the Electric Power Research Institute, FERC, the Institute for Electric Efficiency, the Ontario Energy Board, the Saudi Electricity and Co-Generation Regulatory Authority, and the World Bank. His work has been cited in publications such as *The Economist, The New York Times*, and *USA Today* and he has appeared on Fox News and National Public Radio.

Dr. Faruqui is the author, co-author or editor of four books and more than 150 articles, papers, and reports on efficient energy use, some of which are featured on the websites of the Harvard Electricity Policy Group and the Social Science Research Network. He has taught economics at San Jose State University, the University of California at Davis and the University of Karachi. He holds a an M.A. in agricultural economics and a Ph. D. in economics from The University of California at Davis, where he was a Regents Fellow, and B.A. and M.A. degrees in economics from The University of Karachi, where he was awarded the Gold Medal in economics.

AREAS OF EXPERTISE

- *Innovative pricing.* He has identified, designed and analyzed the efficiency and equity benefits of introducing innovative pricing designs such as three-part rates, including fixed monthly charges, demand charges and time-varying energy charges; dynamic pricing rates, including critical peak pricing, variable peak pricing and real-time pricing; time-of-use pricing; and inclining block rates.
- *Regulatory strategy.* He has helped design forward-looking programs and services that exploit recent advances in rate design and digital technologies in order to lower customer bills and improve utility earnings while lowering the carbon footprint and preserving system reliability.

- *Cost-benefit analysis of advanced metering infrastructure*. He has assessed the feasibility of introducing smart meters and other devices, such as programmable communicating thermostats that promote demand response, into the energy marketplace, in addition to new appliances, buildings, and industrial processes that improve energy efficiency.
- *Demand forecasting and weather normalization.* He has pioneered the use of a wide variety of models for forecasting product demand in the near-, medium-, and long-term, using econometric, time series, and engineering methods. These models have been used to bid into energy procurement auctions, plan capacity additions, design customer-side programs, and weather normalize sales.
- *Customer choice*. He has developed methods for surveying customers in order to elicit their preferences for alternative energy products and alternative energy suppliers. These methods have been used to predict the market size of these products and to estimate the market share of specific suppliers.
- *Hedging, risk management, and market design*. He has helped design a wide range of financial products that help customers and utilities cope with the unique opportunities and challenges posed by a competitive market for electricity. He conducted a widely-cited market simulation to show that real-time pricing of electricity could have saved Californians millions of dollars during the Energy Crisis by lowering peak demands and prices in the wholesale market.
- *Competitive strategy*. He has helped clients develop and implement competitive marketing strategies by drawing on his knowledge of the energy needs of end-use customers, their values and decision-making practices, and their competitive options. He has helped companies reshape and transform their marketing organization and reposition themselves for a competitive marketplace. He has also helped government-owned entities in the developing world prepare for privatization by benchmarking their planning, retailing, and distribution processes against industry best practices, and suggesting improvements by specifying quantitative metrics and follow-up procedures.
- *Design and evaluation of marketing programs.* He has helped generate ideas for new products and services, identified successful design characteristics through

customer surveys and focus groups, and test marketed new concepts through pilots and experiments.

- *Expert witness.* He has testified or appeared before state commissions in Arkansas, California, Colorado, Connecticut, Delaware, the District of Columbia, Illinois, Indiana, Iowa, Kansas, Michigan, Maryland, Ontario (Canada) and Pennsylvania. He has assisted clients in submitting testimony in Georgia and Minnesota. He has made presentations to the California Energy Commission, the California Senate, the Congressional Office of Technology Assessment, the Kentucky Commission, the Minnesota Department of Commerce, the Minnesota Senate, the Missouri Public Service Commission, and the Electricity Pricing Collaborative in the state of Washington. In addition, he has led a variety of professional seminars and workshops on public utility economics around the world and taught economics at the university level.

EXPERIENCE

Innovative Pricing

- **Report examining the costs and benefits of dynamic pricing in the Australian energy market.** For the Australian Energy Market Commission (AEMC), developed a report that reviews the various forms of dynamic pricing, such as time-of-use pricing, critical peak pricing, peak time rebates, and real time pricing, for a variety of performance metrics including economic efficiency, equity, bill risk, revenue risk, and risk to vulnerable customers. It also discusses ways in which dynamic pricing can be rolled out in Australia to raise load factors and lower average energy costs for all consumers without harming vulnerable consumers, such as those with low incomes or medical conditions requiring the use of electricity.

- **Whitepaper on emerging issues in innovative pricing.** For the Regulatory Assistance Project (RAP), developed a whitepaper on emerging issues and best practices in innovative rate design and deployment. The paper includes an overview of AMI-enabled electricity pricing options, recommendations for designing the rates and conducting experimental pilots, an overview of recent pilots, full-deployment case studies, and a blueprint for rolling out innovative rate designs. The paper's audience is international regulators in regions that are exploring the potential benefits of smart metering and innovative pricing.

- **Assessing the full benefits of real-time pricing.** For two large Midwestern utilities, assessed and, where possible, quantified the potential benefits of the existing residential real-time pricing (RTP) rate offering. The analysis included not only "conventional" benefits such as avoided resource costs, but under the direction of the state regulator was expanded to include harder-to-quantify benefits such as improvements to national security and customer service.

- **Pricing and Technology Pilot Design and Impact Evaluation for Connecticut Light & Power (CL&P).** Designed the Plan-It Wise Energy pilot for all classes of customers and subsequently evaluated the Plan-It Wise Energy program (PWEP) in the summer of 2009. PWEP tested the impacts of CPP, PTR, and time of use (TOU) rates on the consumption behaviors of residential and small commercial and industrial customers.

- **Dynamic Pricing Pilot Design and Impact Evaluation: Baltimore Gas & Electric.** Designed and evaluated the Smart Energy Pricing (SEP) pilot, which ran for four years from 2008 to 2011. The pilot tested a variety of rate designs including critical peak pricing and peak time rebates on residential customer consumption patterns. In addition, the pilot tested the impacts of smart thermostats and the Energy Orb.
- **Impact Evaluation of a Residential Dynamic Pricing Experiment: Consumers Energy (Michigan).** Designed the pilot and carried out an impact evaluation with the purpose of measuring the impact of critical peak pricing (CPP) and peak time rebates (PTR) on residential customer consumption patterns. The pilot also tested the influence of switches that remotely adjust the duty cycle of central air conditioners.

- **Impact Simulation of Ameren Illinois Utilities' Power Smart Pricing Program.** Simulated the potential demand response of residential customers enrolled to real-time prices. Results of this simulation were presented to the Midwest ISO's Supply Adequacy Working Group (SAWG) to explore alternative ways of introducing price responsive demand in the region.

- **The Case for Dynamic Pricing: Demand Response Research Center.** Led a project involving the California Public Utilities Commission, the California Energy Commission, the state's three investor-owned utilities, and other stakeholders in the rate design process. Identified key issues and barriers associated with the development of time-based rates. Revisited the fundamental objectives of rate design, including efficiency and equity, with a special emphasis on meeting the state's strongly-articulated needs for demand response and energy efficiency. Developed a score-card for evaluating competing rate designs and applied it to a set of illustrative rates that were created for four customer classes using actual utility data. The work was reviewed by a national peer-review panel.
- **Developed a Customer Price Response Model: Consolidated Edison.** Specified, estimated, tested, and validated a large-scale model that analyzes the response of some 2,000 large commercial customers to rising steam prices. The model includes a module for analyzing conservation behavior, another module for forecasting fuel switching behavior, and a module for forecasting sales and peak demand
- **Design and Impact Evaluation of the Statewide Pricing Pilot: Three California Utilities.** Working with a consortium of California's three investor-owned utilities to design a statewide pricing pilot to test the efficacy of dynamic pricing options for mass-market customers. The pilot was designed using scientific principles of experimental design and measured changes in usage induced by dynamic pricing for over 2,500 residential and small commercial and industrial customers. The impact evaluation was carried out using state-of-the-art econometric models. Information from the pilot was used by all three utilities in their business cases for advanced metering infrastructure (AMI). The project was conducted through a public process involving the state's two regulatory commissions, the power agency, and several other parties.
- **Economics of Dynamic Pricing: Two California Utilities.** Reviewed a wide range of dynamic pricing options for mass-market customers. Conducted an initial cost-effectiveness analysis and updated the analysis with new estimates of avoided costs and results from a survey of customers that yielded estimates of likely participation rates.

- **Economics of Time-of-Use Pricing: A Pacific Northwest Utility.** This utility ran the nation's largest time-of-use pricing pilot program. Assessed the cost-effectiveness of alternative pricing options from a variety of different perspectives. Options included a standard three-part time-of-use rate and a quasi-real time variant where the prices vary by day. Worked with the client in developing a regulatory strategy. Worked later with a collaborative to analyze the program's economics under a variety of scenarios of the market environment.
- **Economics of Dynamic Pricing Options for Mass Market Customers - Client: A Multi-State Utility.** Identified a variety of pricing options suited to meet the needs of mass-market customers, and assessed their cost-effectiveness. Options included standard three-part time-of-use rates, critical peak pricing, and extreme-day pricing. Developed plans for implementing a pilot program to obtain primary data on customer acceptance and load shifting potential. Worked with the client in developing a regulatory strategy.
- **Real-Time Pricing in California - Client: California Energy Commission.** Surveyed the national experience with real-time pricing of electricity, directed at large power customers. Identified lessons learned and reviewed the reasons why California was unable to implement real-time pricing. Catalogued the barriers to implementing real-time pricing in California, and developed a program of research for mitigating the impacts of these barriers.
- **Market-Based Pricing of Electricity - Client: A Large Southern Utility.** Reviewed pricing methodologies in a variety of competitive industries including airlines, beverages, and automobiles. Recommended a path that could be used to transition from a regulated utility environment to an open market environment featuring customer choice in both wholesale and retail markets. Held a series of seminars for senior management and their staffs on the new methodologies.
- **Tools for Electricity Pricing - Client: Consortium of Several U.S. and Foreign Utilities.** Developed Product Mix, a software package that uses modern finance theory and econometrics to establish a profit-maximizing menu of pricing products. The products range from the traditional fixed-price product to time-of-use prices to hourly real-time prices, and also include products that can hedge customers' risks based on financial derivatives. Outputs include market share,

gross revenues, and profits by product and provider. The calculations are performed using probabilistic simulation, and results are provided as means and standard deviations. Additional results include delta and gamma parameters that can be used for corporate risk management. The software relies on a database of customer load response to various pricing options called StatsBank. This database was created by metering the hourly loads of about one thousand commercial and industrial customers in the United States and the United Kingdom.

- **Risk-Based Pricing - Client: Midwestern Utility.** Developed and tested new pricing products for this utility that allowed it to offer risk management services to its customers. One of the products dealt with weather risk; another one dealt with risk that real-time prices might peak on a day when the customer does not find it economically viable to cut back operations.

Demand Response

- **National Action Plan for Demand Response: Federal Energy Regulatory Commission.** Led a consulting team developing a national action plan for demand response (DR). The national action plan outlined the steps that need to be taken in order to maximize the amount of cost-effective DR that can be implemented. The final document was filed with U.S. Congress in June 2010.
- **National Assessment of Demand Response Potential: Federal Energy Regulatory Commission.** Led a team of consultants to assess the economic and achievable potential for demand response programs on a state-by-state basis. The assessment was filed with the U.S. Congress in 2009, as required by the Energy Independence and Security Act of 2007.
- **Evaluation of the Demand Response Benefits of Advanced Metering Infrastructure: Mid-Atlantic Utility.** Conducted a comprehensive assessment of the benefits of advanced metering infrastructure (AMI) by developing dynamic pricing rates that are enabled by AMI. The analysis focused on customers in the residential class and commercial and industrial customers under 600 kW load.
- **Estimation of Demand Response Impacts: Major California Utility.** Worked with the staff of this electric utility in designing dynamic pricing options for residential and small commercial and industrial customers. These options were

designed to promote demand response during critical peak days. The analysis supported the utility's advanced metering infrastructure (AMI) filing with the California Public Utilities Commission. Subsequently, the commission unanimously approved a $1.7 billion plan for rolling out nine million electric and gas meters based in part on this project work.

Smart Grid Strategy

- **Development of a smart grid investment roadmap for Vietnamese utilities.** For the five Vietnamese power corporations, developed a roadmap to guide future smart grid investment decisions. The report identified and described the various smart grid investment options, established objectives for smart grid deployment, presented a multi-phase approach to deploying the smart grid, and provided preliminary recommendations regarding the best investment opportunities. Also presented relevant case studies and an assessment of the current state of the Vietnamese power grid. The project involved in-country meetings as well as a stakeholder workshop that was conducted by *Brattle* staff.

- **Cost-Benefit Analysis of the Smart Grid: Rocky Mountain Utility.** Reviewed the leading studies on the economics of the smart grid and used the findings to assess the likely cost-effectiveness of deploying the smart grid in one geographical location.

- **Modeling benefits of smart grid deployment strategies.** Developed a model for assessing benefits of smart grid deployment strategies over a long-term (e.g., 20-year) forecast horizon. The model, called iGrid, is used to evaluate seven distinct smart grid programs and technologies (e.g., dynamic pricing, energy storage, PHEVs) against seven key metrics of value (e.g., avoided resource costs, improved reliability).

- **Smart grid strategy in Canada.** The Alberta Utilities Commission (AUC) was charged with responding to a Smart Grid Inquiry issued by the provincial government. Advised the AUC on the smart grid, and what impacts it might have in Alberta.

- **Smart grid deployment analysis for collaborative of utilities.** Adapted the iGrid modeling tool to meet the needs of a collaborative of utilities in the southern U.S. In addition to quantifying the benefits of smart grid programs and technologies (e.g., advanced metering infrastructure deployment and direct load control), the model was used to estimate the costs of installing and implementing each of the smart grid programs and technologies.

- **Development of a smart grid cost-benefit analysis framework.** For the Electric Power Research Institute (EPRI) and the U.S. DOE, contributed to the development of an approach for assessing the costs and benefits of the DOE's smart grid demonstration programs.

- **Analysis of the benefits of increased access to energy consumption information.** For a large technology firm, assessed market opportunities for providing customers with increased access to real time information regarding their energy consumption patterns. The analysis includes an assessment of deployments of information display technologies and analysis of the potential benefits that are created by deploying these technologies.

- **Developing a plan for integrated smart grid systems.** For a large California utility, helped to develop applications for funding for a project to demonstrate how an integrated smart grid system (including customer-facing technologies) would operate and provide benefits.

Demand Forecasting

- **Comprehensive Review of Load Forecasting Methodology: PJM Interconnection.** Conducted a comprehensive review of models for forecasting peak demand and re-estimated new models to validate recommendations. Individual models were developed for 18 transmission zones as well as a model for the RTO system.

- **Analyzed Downward Trend: Western Utility.** We conducted a strategic review of why sales had been lower than forecast in a year when economic activity had been brisk. We developed a forecasting model for identifying what had caused the drop in sales and its results were used in an executive presentation to the utility's board of directors. We also developed a time series model for more accurately forecasting sales in the near term and this model is now being used for revenue forecasting and budgetary planning.

- **Analyzed Why Models are Under-Forecasting: Southwestern Utility.** Reviewed the entire suite of load forecasting models, including models for forecasting aggregate system peak demand, electricity consumption per customer by sector and the number of customers by sector. We ran a variety of forecasting experiments to assess both the ex-ante and ex-post accuracy of the models and made several recommendations to senior management.
- **U.S. Demand Forecast: Edison Electric Institute.** For the U.S. as a whole, we developed a base case forecast and several alternative case forecasts of electric energy consumption by end use and sector. We subsequently developed forecasts that were based on EPRI's system of end-use forecasting models. The project was done in close coordination with several utilities and some of the results were published in book form.
- **Developed Models for Forecasting Hourly Loads: Merchant Generation and Trading Company.** Using primary data on customer loads, weather conditions, and economic activity, developed models for forecasting hourly loads for residential, commercial, and industrial customers for three utilities in a Midwestern state. The information was used to develop bids into an auction for supplying basic generation services.
- **Gas Demand Forecasting System - Client: A Leading Gas Marketing and Trading Company, Texas.** Developed a system for gas nominations for a leading gas marketing company that operated in 23 local distribution company service areas. The system made week-ahead and month-ahead forecasts using advanced forecasting methods. Its objective was to improve the marketing company's profitability by minimizing penalties associated with forecasting errors.

Demand Side Management

- **The Economics of Biofuels.** For a western utility that is facing stringent renewable portfolio standards and that is heavily dependent on imported fossil fuels, carried out a systematic assessment of the technical and economic ability of biofuels to replace fossil fuels.

- **Assessment of Demand-Side Management and Rate Design Options: Large Middle Eastern Electric Utility.** Prepared an assessment of demand-side management and rate design options for the four operating areas and six market segments. Quantified the potential gains in economic efficiency that would result from such options and identified high priority programs for pilot testing and implementation. Held workshops and seminars for senior management, managers, and staff to explain the methodology, data, results, and policy implications.
- **Likely Future Impact of Demand-Side Programs on Carbon Emissions - Client: The Keystone Center.** As part of the Keystone Dialogue on Climate Change, developed scenarios of future demand-side program impacts, and assessed the impact of these programs on carbon emissions. The analysis was carried out at the national level for the U.S. economy, and involved a bottom-up approach involving many different types of programs including dynamic pricing, energy efficiency, and traditional load management.
- **Sustaining Energy Efficiency Services in a Restructured Market - Client: Southern California Edison.** Helped in the development of a regulatory strategy for implementing energy efficiency strategies in a restructured marketplace. Identified the various players that are likely to operate in a competitive market, such as third-party energy service companies (ESCOS) and utility affiliates. Assessed their objectives, strengths, and weaknesses and recommended a strategy for the client's adoption. This strategy allowed the client to participate in the new market place, contribute to public policy objectives, and not lose market share to new entrants. This strategy has been embraced by a coalition of several organizations involved in the California PUC's working group on public purpose programs.
- **Organizational Assessments of Capability for Energy Efficiency - Client: U.S. Agency for International Development, Cairo, Egypt.** Conducted in-depth interviews with senior executives of several energy organizations, including utilities, government agencies, and ministries to determine their goals and capabilities for implementing programs to improve energy end-use efficiency

in Egypt. The interviews probed the likely future role of these organizations in a privatized energy market, and were designed to help develop U.S. AID's future funding agenda.

- **Enhancing Profitability Through Energy Efficiency Services - Client: Jamaica Public Service Company.** Developed a plan for enhancing utility profitability by providing financial incentives to the client utility, and presented it for review and discussion to the utility's senior management and Jamaica's new Office of Utility Regulation. Developed regulatory procedures and legislative language to support the implementation of the plan. Conducted training sessions for the staff of the utility and the regulatory body.

Advanced Technology Assessment

- **Competitive Energy and Environmental Technologies - Clients: Consortium of clients, led by Southern California Edison, Included the Los Angeles Department of Water and Power and the California Energy Commission.** Developed a new approach to segmenting the market for electrotechnologies, relying on factors such as type of industry, type of process and end use application, and size of product. Developed a user-friendly system for assessing the competitiveness of a wide range of electric and gas-fired technologies in more than 100 four-digit SIC code manufacturing industries and 20 commercial businesses. The system includes a database on more than 200 end-use technologies, and a model of customer decision making.
- **Market Infrastructure of Energy Efficient Technologies - Client: EPRI.** Reviewed the market infrastructure of five key end-use technologies, and identified ways in which the infrastructure could be improved to increase the penetration of these technologies. Data was obtained through telephone interviews with equipment manufacturers, engineering firms, contractors, and end-use customers

TESTIMONY

Arkansas

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Arizona

Direct Testimony before the Arizona Corporation Commission on behalf of Arizona Public Service Company, in the matter of the Application for UNS Electric, Inc. for the Establishment of Just and Reasonable Rates and Charges Designed to Realize a Reasonable Rate of Return on the Fair Value of the Properties of UNS Electric, Inc. Devoted to the its Operations Throughout the State of Arizona, and for Related Approvals, Docket No. E-04204A-15-0142, December 9, 2015.

California

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Qualifications and prepared testimony before the Public Utilities Commission of the State of California, on behalf of Southern California Edison, Edison SmartConnect™ Deployment Funding and Cost Recovery, exhibit SCE-4, July 31, 2007.

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Colorado

Rebuttal testimony before the Public Utilities Commission of the State of Colorado in the Matter of Advice Letter No. 1535 by Public Service Company of Colorado to Revise its Colorado PUC No.7 Electric Tariff to Reflect Revised Rates and Rate Schedules to be Effective on June 5, 2009. Docket No. 09al-299e, November 25, 2009.

Direct testimony before the Public Utilities Commission of the State of Colorado, on behalf of Public Service Company of Colorado, on the tariff sheets filed by Public Service Company of Colorado with advice letter No. 1535 – Electric. Docket No. 09S-__E, May 1, 2009.

Connecticut

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District of Columbia

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Illinois

Direct testimony on rehearing before the Illinois Commerce Commission on behalf of Ameren Illinois Company, on the Smart Grid Advanced Metering Infrastructure Deployment Plan, Docket No. 12-0244, June 28, 2012.

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Prepared rebuttal testimony before the Illinois Commerce Commission on behalf of Commonwealth Edison, on the Advanced Metering Infrastructure Pilot Program, ICC Docket No. 06-0617, October 30, 2006.

Indiana

Direct testimony before the State of Indiana, Indiana Utility Regulatory Commission, on behalf of Vectren South, on the smart grid. Cause no. 43810, 2009.

Kansas

Direct testimony before the State Corporation Commission of the State of Kansas, on behalf of Westar Energy, in the matter of the Application of Westar Energy, Inc. and Kansas Gas and Electric Company to Make Certain Changes in Their Charges for Electric Service, Docket No. 15-WSEE-115-RTS, March 2, 2015.

Louisiana

Direct testimony before the Louisiana Public Service Commission on behalf of Entergy Louisiana, LLC, in the matter of Approval to Implement a Permanent Advanced Metering System and Request for Cost Recovery and Related Relief in accordance with Louisiana Public Service Commission General Order dated September 22, 2009, R-29213, November 2016.

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Maryland

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Prepared direct testimony before the Maryland Public Service Commission, on behalf of Baltimore Gas and Electric Company, on the findings of BGE's Smart Energy Pricing ("SEP") Pilot program. Case No. 9208, July 10, 2009.

Minnesota

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Mississippi

Direct testimony before the Mississippi Public Service Commission, on behalf of Entergy Mississippi, Inc., in the matter of Application for Approval of Advanced Metering Infrastructure and Related Modernization Improvements, EC-123-0082-00, November 2016.

Nevada

Prepared rebuttal testimony before the Public Utilities Commission of Nevada on behalf of Nevada Power Company and Sierra Pacific Power Company d/b/a NV Energy, in the matter of net metering and distributed generation cost of service and tariff design, Docket Nos. 15-07041 and 15-07042, November 3, 2015.

Prepared direct testimony before the Public Utilities Commission of Nevada on behalf of Nevada Power Company d/b/a NV Energy, in the matter of the application for approval of a cost of service study and net metering tariffs, Docket No. 15-07, July 31, 2015.

New Mexico

Direct testimony before the New Mexico Regulation Commission on behalf of Public Service Company of New Mexico in the matter of the Application of Public Service Company of New Mexico for Revision of its Retail Electric Rates Pursuant to Advice Notice No. 507, Case No. 14-00332-UT, December 11, 2014.

Oklahoma

Responsive Testimony before the Corporation Commission of Oklahoma on behalf of Oklahoma Gas and Electric Company in the matter of the Application of Brandy L. Wreath, Director of the Public Utility Division, for Determination of the Calculation of Lost Net Revenues and Shared Savings Pursuant to the Demand Program Rider of Oklahoma Gas and Electric Company, Cause No. PUD 201500153, May 13, 2015.

Pennsylvania

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REGULATORY APPEARANCES

Arkansas

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Delaware

Presented before the Delaware Public Service Commission, “The Demand Response Impacts of PHI’s Dynamic Pricing Program” Delaware, September 5, 2007.

Kansas

Presented before the State Corporation Commission of the State of Kansas, “The Impact of Dynamic Pricing on Westar Energy" at the Smart Grid and Energy Storage Roundtable, Topeka, Kansas, September 18, 2009.

Ohio

Presented before the Ohio Public Utilities Commission, “Dynamic Pricing for Residential and Small C&I Customers" at the Technical Workshop, Columbus, Ohio, March 28, 2012.

Texas

Presented before the Public Utility Commission of Texas, “Direct Load Control of Residential Air Conditioners in Texas,” at the PUCT Open Meeting, Austin, Texas, October 25, 2012.

PUBLICATIONS

Books

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"*Arcturus*: An International Repository of Evidence on Dynamic Pricing," with Sanem Sergici. *Smart Grid Applications and Developments, Green Energy and Technology*. Ed. Daphne Mah, Ed. Peter Hills, Ed. Victor O. K. Li, Ed. Richard Balme. Springer, 2014. 59-74.

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Appendix C: Kansas Utilities Offering a Demand Charge

Utility	Utility Ownership	Customers Served	Mandatory for Some C&I Customers?	Mandatory for All C&I Customers?
	[1]	[2]	[3]	[4]
Westar Energy Inc	IOU	699,690		✓
Kansas City Power & Light Co	IOU	249,183		✓
Kansas City Board of Public Utilities	Muni	64,329		✓
Midwest Energy Inc	DistCoop	50,453	✓	
Wheatland Electric Coop Inc	DistCoop	32,854		✓
Prairie Land Electric Coop Inc	DistCoop	25,389	✓	
Victory Electric Coop Association Inc	DistCoop	19,608	✓	
Pioneer Electric Coop Inc KS	DistCoop	16,952		✓
Western Coop Electric Association Inc	DistCoop	12,301	✓	
Garden City KS (City of)	Muni	11,420	✓	
Heartland Rural Electric Coop	DistCoop	11,275	✓	
Rolling Hills Electric Coop	DistCoop	11,189	✓	

Note:
Not all customers under Kansas City Board of Public Utilities' Small General Service tariff have demand meters. If one of these customers exceeds a threshhold load, a demand meter may be installed by the utility.

Sources:
[1] & [2]: ABB. Electric Company Retail Sales - Combined by State - 2015.
[3] & [4]: Utility tariffs as of October 2016. Rolling Hills Electric Coop data from OpenEI.org.

Appendix D: U.S. Utilities Offering a Residential Demand Charge

#	Utility	Utility Ownership	State	Residential Customers Served	Fixed charge ($/month)	Demand Charge ($/kW-month)		Timing of demand measurement	Demand interval	Combined with Energy TOU?	Applicable Residential Customer Segment	Mandatory or Voluntary
						Summer	Winter					
[1]	Alabama Power	Investor Owned	AL	1,241,998	14.50	1.50	1.50	Any time	15 min	Yes	All	Voluntary
[2]	Alaska Electric Light and Power	Investor Owned	AK	13,968	11.49	6.72	11.11	Any time	Unknown	No	All	Voluntary
[3]	Albemarle Electric Membership Corp	Cooperative	NC	11,521	27.00	13.50	13.50	Peak Coincident	15 min	Yes	All	Voluntary
[4]	Arizona Public Service	Investor Owned	AZ	1,019,292	16.96	13.50	9.30	Peak Coincident	60 min	Yes	All	Voluntary
[5]	Black Hills Power	Investor Owned	SD	54,617	13.00	8.10	8.10	Any time	15 min	No	All	Voluntary
[6]	Black Hills Power	Investor Owned	WY	2,153	15.50	8.25	8.25	Any time	15 min	No	All	Voluntary
[7]	Butler Rural Electric Cooperative	Cooperative	KS	7,000	25.00	5.00	5.00	Any time	60 min	No	All	Mandatory
[8]	Carteret-Craven Electric Cooperative	Cooperative	NC	35,269	30.00	11.95	9.95	Peak Coincident	15 min	No	All	Voluntary
[9]	Central Electric Membership Corp	Cooperative	NC	19,574	34.00	8.55	7.50	Peak Coincident	15 min	Yes	All	Voluntary
[10]	City of Fort Collins Utilities	Municipal	CO	60,464	5.37	2.50	2.50	Any time	Unknown	No	All	Voluntary
[11]	City of Glasgow	Municipal	KY	5,315	29.16	11.33	10.37	Peak Coincident	30 min	Yes	All	Voluntary (opt-out)
[12]	City of Kinston	Municipal	NC	9,776	14.95	9.35	9.35	Peak Coincident	15 min	No	All	Voluntary
[13]	City of Longmont	Municipal	CO	34,697	15.40	5.75	5.75	Any time	15 min	No	All	Voluntary
[14]	Dakota Electric Association	Cooperative	MN	94,924	12.00	14.70	11.10	Any time	15 min	No	All	Voluntary
[15]	Dominion	Investor Owned	NC	101,158	16.39	8.25	4.83	Peak Coincident	30 min	Yes	All	Voluntary
[16]	Dominion	Investor Owned	VA	2,105,500	12.00	5.68	3.95	Peak Coincident	30 min	Yes	All	Voluntary
[17]	Duke Energy Carolinas, LLC	Investor Owned	NC	1,608,151	13.38	7.77	3.88	Peak Coincident	30 min	Yes	All	Voluntary
[18]	Duke Energy Carolinas, LLC	Investor Owned	SC	460,178	9.93	8.15	4.00	Peak Coincident	30 min	Yes	All	Voluntary
[19]	Edgecombe-Martin County EMC	Cooperative	NC	10,550	31.00	8.75	8.00	Peak Coincident	Unknown	No	All	Voluntary
[20]	Fort Morgan	Municipal	CO	5,273	6.13	10.22	10.22	Unknown	Unknown	No	All	Voluntary
[21]	Georgia Power	Investor Owned	GA	2,072,622	10.00	6.64	6.64	Any time	30 min	Yes	All	Voluntary
[22]	Kentucky Utilities Company	Investor Owned	KY	420,219	10.75	13.05	13.05	Peak Coincident	15 min	No	All	Voluntary
[23]	Lakeland Electric	Municipal	FL	101,971	9.50	5.60	5.60	Peak Coincident	30 min	No	All	Voluntary
[24]	Louisville Gas and Electric	Investor Owned	KY	348,048	10.75	12.38	12.38	Peak Coincident	15 min	No	All	Voluntary
[25]	Loveland Electric	Municipal	CO	29,676	21.23	9.50	7.29	Any time	15 min	No	All	Voluntary
[26]	Mid-Carolina Electric Cooperative	Cooperative	SC	55,000	24.00	12.00	12.00	Any time	60 min	No	All	Mandatory
[27]	Midwest Energy Inc	Cooperative	KS	29,951	22.00	6.40	6.40	Any time	15 min	No	All	Voluntary
[28]	Otter Tail Power Company	Investor Owned	MN	47,699	16.00	6.08	5.11	Any time	60 min	No	All	Voluntary
[29]	Otter Tail Power Company	Investor Owned	ND	44,910	18.38	6.52	2.63	Any time	60 min	No	All	Voluntary
[30]	Otter Tail Power Company	Investor Owned	SD	8,648	13.00	7.05	5.93	Any time	60 min	No	All	Voluntary
[31]	Salt River Project	Political Subdivision	AZ	891,668	32.44 or 45.44	9.59 to 34.19	3.41 to 9.37	Peak Coincident	30 min	Yes	DG only	Mandatory
[32]	Smithfield	Municipal	NC	3,386	17.00	5.93	5.93	Peak Coincident	15 min	Yes	All	Voluntary
[33]	Swanton Village Electric Department	Municipal	VT	3,208	26.57	6.77	6.77	Any time	Unknown	No	All	Mandatory
[34]	Tri-County Electric Cooperative	Cooperative	FL	15,859	23.00	7.00	7.00	Any time	15 min	No	All	Voluntary
[35]	Vigilante Electric Cooperative	Cooperative	MT	7,889	23.00	0.50 per KVA	0.50 per KVA	Any time	Unknown	No	All	Mandatory
[36]	Westar Energy	Investor Owned	KS	700,000	16.50	6.78	2.09	Any time	30 min	No	All	Voluntary
[37]	Xcel Energy (PSCo)	Investor Owned	CO	1,182,093	12.25	8.57	6.59	Any time	15 min	No	All	Voluntary

Notes accompanying table of U.S. residential demand charge offerings

Sources: Utility tariffs as of June 2016**,** and "Form EIA-861 2013 data files, EIA_861_Retail_Sales_2013.xls" (for Utility ownership and Residential Customers Served columns).

Notes:

Peak periods are applicable from Monday through Friday excluding holidays. For some utilities, the monthly fixed charge has been calculated by multiplying a daily charge by 30.5.

[2]: Mandatory if customer consumes more than 5,000 kWh per month for three consecutive months or has a recorded peak demand of 20 KW for three consecutive months.

[3]: The monthly fixed charge is a daily basic service charge multiplied by 30.5 days.

[5]-[6]: Black Hills also offers an optional time-of-use rate that includes both energy and demand charges for customers owning demand controllers.

[11]: The GEBP three-part rate offering is under review (as of February 2017) and is currently believed to be the default (opt-out) rate for residential customers pending further change.

[16]: Demand charge is the sum of the distribution demand charge and the generation demand charge. The distribution demand charge is $1.612/kW and the generation demand charge is $4.070/kW for the summer and $2.334/kW for the winter.

[20]: The timing of demand measurement and the demand interval are not explicitly identified in the publicly available information we have reviewed.

[25]: The demand rate is closed to new customers after December 31, 2014.

[27]: The demand charge is based on the greater of the highest average 15 minute kW demand measured during the period for which the bill is rendered, and 80% of the average 15 minute maximum demand for the last three summer months.

[28]-[30]: Demand is measured as the maximum winter demand for the most recent 12 months. New customers have an assumed demand of 3 kW for their first year. Fixed charge for MN is customer charge per month plus facilities charge per month. Fixed charge for ND and SD is just customer charge per month.

[31]: Customers below 200 amps pay a fixed charge of $32.55 per month and customers above 200 amps pay $45.44 per month. Demand charges vary across three seasons: Winter, Summer (May, June, September, and October), and On-Peak Summer (July and August). The summer demand charges shown here apply for the On-Peak Summer period. The (on-peak) summer demand charge is $9.59 for up to 3kW of demand, 17.82 for the next 7kW, and 34.19 for over 10kW. The winter demand charge is $3.41 for up to 3kW, 5.46 for the next 7kW, and $9.37 over 10kW. The utility is experimentally offering the rate plan to a limited number of non-DG customers.

[33]: The demand charge is based on the greater of the measured demand for the current month and 85% of the highest recorded demand established during the preceding eleven months. The rate is mandatory for all residential customers with monthly consumption equal to or greater than 1,800 kWh, measured on a rolling 12 month average basis.

[35]: The demand charge applies only to KVA greater than 15 KVA

Appendix E: Methodology and Assumptions in Price Response Analysis

This appendix summarizes the assumptions behind the estimation of changes in customer electricity consumption patterns in response to the introduction of a three-part rate.

In estimating customer response to a demand charge, I assumed that customers would respond similar to the way they would respond to a time-of-use (TOU) rate. This assumption is supported by a study conducted with utility customers in Wisconsin, which found that equivalent demand charges and energy-only time-of-use rates produced similar levels of price response among participants in the pilot program.[41]

A difference between that Wisconsin study and Westar's rate offering is that Westar's proposed rate design measures demand based on maximum billing demand, whereas the rate tested in Wisconsin restricted measurement of demand to a peak period. However, upon analysis of Westar's load research data, I found that the majority (75%) of residential DG customers' top 15 demand hours each month will occur between the hours of 5 and 11 pm. Through simple messaging, it would be possible to make customers aware of this time period as the period during which electricity consumption is driving a significant portion of their bill, akin to the peak period of a TOU rate. Therefore, for the purposes of simulating customer response, I treated the three-part rate like a TOU rate with a peak period from 5 to 11 pm.

The demand charge was levelized across the "peak" hours from 5 to 11 pm and converted to a volumetric (cents per kilowatt-hour) charge for the purposes of simulation. This effectively created a TOU rate with an all-in peak period price of 28.1 cents/kWh and an all-in off-peak period price of 14.6 cents/kWh in the summer.[42] In the winter, the all-in peak and off-peak prices are 24 cents/kWh and 18.7 cents/kWh, respectively.

There are two important effects to capture when modeling customer price response. The first is what I call the "load shifting" effect (sometimes also known as the price elasticity of substitution). It captures the customer's incentive to shift consumption from the higher priced period to the lower priced period. The second effect is called the "average price" effect. It captures a customer's general reaction to a change in their overall bill – if the customer's bill (or average price) increases under the three-part rate, one would expect them to consume less electricity in response (and vice versa).

Based on a review of price elasticities from prior studies, including assumptions from a 2012 Christensen Associates rate study for the KCC, I conservatively assumed an elasticity of

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41 Caves, D., Christensen, L., Herriges, J., 1984. "Modeling alternative residential peak-load electricity rate structures." *J. Econometrics*. Vol 24, Issue 3, 249-268.

42 An all-in price incorporates all charges on a levelized volumetric (cents per kWh) basis.

substitution of -0.06 to capture the load shifting effect and a "daily elasticity" of -0.045 to capture the average price effect. I also tested high and low elasticity cases, as discussed below. To avoid overstating the reduction in demand, the impact of the average price effect was not applied to the customer's peak demand, but was applied to all other hours.

Formulaically, each customer's price response is calculated as follows:

<u>The load shifting effect</u>

Change in peak period consumption:

$$P_s = \left(\frac{R_{d-on}}{R_{d-off}} - 1\right) * E_s$$

Where,
P_s = % load shift from on- to off-peak
$R_{d\text{-}on}$ = levelized all-in three part rate (on-peak)
$R_{d\text{-}off}$ = levelized all-in three part rate (off-peak)
E_s = elasticity of substitution

Hourly on-peak consumption change [applies for hours 5pm-11pm]:

$$H_1 = \left(\frac{P_s * C_o}{H_{on}}\right) + H_0$$

Where,
H_1 = new hourly electricity consumption
P_s = % load shift from on- to off-peak
C_o = monthly electricity consumption during on-peak hours
H_{on} = monthly count of on-peak hours
H_0 = original hourly electricity consumption

Hourly off-peak consumption change [applies for hours 12am – 4pm]:

$$H_1 = H_0 - \left(\frac{P_s * C_o}{H_{off}}\right)$$

Where,
H_1 = new hourly electricity consumption
P_s = % load shift from on- to off-peak
C_o = monthly electricity consumption during on-peak hours
H_{off} = monthly count of off-peak hours
H_0 = original hourly electricity consumption

Each customer's maximum demand, modified to account for the shift in consumption from on-peak to off-peak hours, is multiplied by the summer and winter demand rates to calculate the change in demand charge due to the load shifting effect.

Average price effect

$$P_{er} = \left(\frac{R_d}{R_{std}} - 1\right) * E_d$$

Where,
P_{er} = % electricity consumption change
R_d = levelized all-in three part rate
R_{std} = levelized all-in standard two part rate
E_d = daily elasticity

New Electricity Consumption:

$$EC_1 = (1 + P_{er}) * EC_0$$

Where,
EC_1 = new electricity consumption
P_{er} = % electricity consumption change
EC_0 = original electricity consumption

The new electricity consumption is multiplied by the variable rate to calculate the change in energy charge due to the average price effect. To avoid overstating the reduction in maximum demand, the average price effect is assumed not to incrementally change the customer's max demand; in other words, the only impact on max demand is from the load shifting effect.

Price response was estimated on a seasonal basis for each customer in the load research sample, assuming each customer had installed a rooftop PV system serving 80% of their annual electricity needs.

I tested a range of price elasticities to account for the uncertainty in this assumption. The range is based on a review of price elasticities from prior pricing pilots conducted around the U.S. The price elasticity cases are summarized in Table A-1 below.

Table A-1: Price Elasticity Sensitivity Cases

	Elasticity of Substitution	Daily Elasticity
Low	-0.04	-0.030
Mid	-0.06	-0.045
High	-0.15	-0.060

The reduction in the average DG customer's bill increase due to price response for each price elasticity case is summarized in Table A-2 below.[43]

Table A-2: Reduction in Average DG Customer Bill Increase due to Price Response

	Change (%)		Change ($/mo)	
	Summer	Winter	Summer	Winter
Low	-3.0%	-2.0%	$1.41	$0.16
Mid	-4.5%	-2.8%	$2.11	$0.24
High	-8.4%	-4.4%	$3.99	$0.37

43 As was shown in Section IV (Figure 8) of this affidavit, most DG customers will experience a bill increase when transitioning to the three-part rate. In this table, I have quantified the percent reduction in that bill increase attributable to a reasonable level of price response.

BEFORE THE STATE CORPORATION COMMISSION
OF THE STATE OF KANSAS

In the Matter of the General Investigation to Examine Issues Surrounding Rate Design for Distributed Generation Customers.	)))	Docket No. 16-GIME-403-GIE

AFFIDAVIT OF AHMAD FARUQUI

STATE OF California)
) ss.
COUNTY OF San Francisco)

Ahmad Faruqui, being first duly sworn on his oath, states:

1. My name is Ahmad Faruqui. I am a Principal with The Brattle Group.

2. Attached hereto and made a part hereof for all purposes is my Affidavit on behalf of Westar Energy, Inc. having been prepared in written form for introduction into evidence in the above-captioned docket.

3. I have knowledge of the matters set forth therein. I hereby swear and affirm that the information contained in my Affidavit is true and accurate to the best of my knowledge, information and belief.

Ahmad Faruqui

Subscribed and sworn before me this 15th day of March, 2017.

Notary Public

My Commission expires: ____________________

EZEQUIEL VILLALOBOS
Commission # 2034751
Notary Public - California
San Francisco County
My Comm. Expires Aug 16, 2017

A notary public or other officer completing this certificate verifies only the identity of the individual who signed the document to which this certificate is attached, and not the truthfulness, accuracy, or validity of that document.

State of California
County of San Francisco
Subscribed and sworn to (or affirmed) before me this 15 day of March, 2017, by Ahmad Faruqui, proved to me on the basis of satisfactory evidence to be the person(s) who appeared before me.

Signature ____________________ (Seal)

Affidavit Ashley C. Brown in Kansas Generic Docket on Distributed Generation Rate Design

March 2017

Contents

Background and Qualifications

I am the Executive Director of the Harvard Electricity Policy Group (HEPG) at the Harvard Kennedy School, at Harvard University. HEPG is a "think tank" on electricity policy, including but not necessarily limited to pricing, market rules, and regulation, as well as environmental and social considerations in electricity markets. HEPG, as an institution, never takes a position on policy matters, so this paper represents solely my opinion, and not that of the HEPG or any other organization with which I may be affiliated.

I am an attorney. I served 10 years as a Commissioner of the Public Utilities Commission of Ohio (1983-1993), where I was appointed and re-appointed by Governor Richard Celeste. I also served as a member of the National Association of Regulatory Utility Commissioners (NARUC) Executive Committee and served three years as Chair of the NARUC Committee on Electricity. I was a member of the Advisory Board of the Electric Power Research Institute. I was also appointed by the U.S. Environmental Protection Agency as a member of the Advisory Committee on Implementation of the Clean Air Act Amendments of 1990. I am also a past member of the Boards of Directors of the National Regulatory Research Institute and the Center for Clean Air Policy. I have served on the Boards of Oglethorpe Power Corporation, Entegra Power Group, and e-Curve, and as Chair of the Municipal Light Advisory Board in Belmont, MA. I serve on the Editorial Advisory Board of the *Electricity Journal*.

I have been at Harvard continuously since 1993. During that time I have also been Senior Consultant at the firm of RCG/Hagler, Bailly, Inc. and have been, at various times in the past, Of Counsel to the law firms of Dewey & LeBouef and Greenberg Traurig. I have also taught in training programs for regulators at Michigan State University, University of Florida, and New Mexico State University (the three NARUC sanctioned training programs for regulators), as well as at Harvard, the European Union's Florence School of Regulation, Association of Brazilian Regulators, and a number of other universities throughout the world. I have advised the World Bank, Asian Development Bank, and the Inter-American Development Bank on energy regulation, and have advised governments and regulators in more than 25 countries around the world, including Brazil, Argentina, Chile, South Africa, Costa Rica, Zambia, Ghana, Tanzania, Namibia, Equatorial Guinea, Liberia, Mozambique, Hungary, Ukraine, Russia, India, Bangladesh, Saudi Arabia, Indonesia, and The Philippines. I have written numerous journal articles and chapters in books on electricity markets and regulation, and am the co-author of the World Bank's *Handbook for Evaluating Infrastructure Regulation.*

I hold a B.S. from Bowling Green State University, an M.A. from the University of Cincinnati, and a J.D. from the University of Dayton. I have also completed all work, except for the dissertation, on a Ph.D. from New York University. My current CV is provided as an attachment.

Introduction

The issue before the State Corporation Commission of the State of Kansas is "whether a separate Residential Standard Distributed Generation Tariff is necessary, and, if so, ***how to structure the Residential Standard Distributed Generation Tariff in order to properly recover just and reasonable costs from customers with distributed generation.***"

In what follows I discuss the following topics:

- A brief explanation of traditional utility ratemaking principles and the development of residential rates;

- The origins of retail net metering for rooftop solar;
- An explanation of how retail net metering fails to satisfy standard criteria for rate design, and an examination of current trends, proposals, and topics of discussion by rate makers regarding net metering;
- The fact that a three part tariff is what is needed to connect how costs are incurred to how they are recovered;
- The fact that using the same rate for distributed generation customers as for full requirements customers results in unreasonable discrimination against non-solar customers and, in the aggregate, imposes an unfair burden on less affluent households;
- The fact that a three part rate structure for rooftop solar customers would be consistent with traditional ratemaking principles, including better aligning costs with customer payments and cost causation, providing incentives for productivity gains for energy producers and for consumers to be more efficient in their consumption, and incentivizing the creation and deployment of technology to provide consumers with the ability to save on their electric bills and reduce their environmental footprint;
- The fact that a three part rate for distributed generation customers would also remove the market distortion associated with retail net metering that disadvantages large-scale wind and solar, despite the fact that utility-scale projects provide many of the same benefits as rooftop solar at considerably less expense;

- The fact that typical arguments in favor of continuing the subsidy inherent in keeping distributed generation/partial requirements customers on the same rate as full requirements customers are based on claims of additional “values” provided by distributed solar power that are highly subjective, speculative, and incomplete, because they fail to consider how rooftop solar compares with other sources of power generation or service provision, and fails to even identify most, if not all, of the costs associated with rooftop solar;
- The fact that an appropriately structured three part rate would incentivize rooftop solar customers to reduce their overall demand costs. A three part rate (which would include a demand charge) would allow rooftop solar customers to benefit from the value they provide to the grid by reducing their overall demand; and
- Finally, that the incentives that could be embedded in a three part rate would encourage innovation and the proliferation of varied business models for the provision of goods and services to help customers economically and efficiently meet their energy needs. Indeed, appropriate rates should make rooftop solar more competitive in the long run. Rooftop solar can succeed without burdening customers who either cannot or choose not to install rooftop solar systems. This would be a welcome outcome that would stem from the proper alignment of rates and costs.

Utility ratemaking principles

The delivery of electricity to homes and businesses has long been understood to be an essential service. The electricity industry, historically, was largely characterized by vertical integration of the full bundle of electric services—generation, transmission, distribution, and retail sales. Utilities bore substantially all the costs associated with these services, which were significant, including not only large upfront costs, but maintenance and improvement of facilities, requiring significant capital outlays.

Utilities are traditionally thought of as having "natural monopolies" over transmission and distribution (including dispatch and control functions).[1] This is because it has long been observed that wires and wires-related (network) services have economies of scale and are in need of central coordination. As monopolies, utilities can supply services at lower cost without the duplication of facilities and other fixed costs. Obviously, it is more efficient not to develop duplicate distribution systems, but potential efficiencies go beyond this. Centralized essential facilities, such as distribution and transmission, whose costs are fixed and/or demand driven enable a system of least-cost dispatch by managing an intertwined causal web of costs, balancing competing efficiencies of generation and transmission, assuring reliability, and using long-term resource planning to minimize costs over the long run by strategically locating new generation assets. It is also critical that load serving utilities play the critically important roles of assuring that the electricity demands of all customers are not only met, but are served on a highly reliable basis. Thus, in contrast with other aspects of the economy, competition in the essential services provided by the fixed distribution and transmission assets of a utility, would ultimately not be able to provide the same level of reliable, universal service, without a substantial increase in costs. Transmission and distribution are natural monopolies because the cost of building

[1] For an early discussion that developed the idea of natural monopolies in gas and water, see, e.g., John Stewart Mill, cited in Garfield and Lovejoy, Public Utility Economics, 1964, p. 15.

competing parallel systems, not to mention the difficulties associated with obtaining right of way, is prohibitive. Furthermore, due to the physics of electricity, the stability of the transmission and distribution systems requires central dispatch and control.

Natural monopolies are typically found in industries with high capital costs and the opportunity for substantial economies of scale. This is a fitting description of the electricity industry, where natural monopolies have been the norm since the beginning of the 20th Century.[2] Typically, utilities were provided with a monopoly over a specific service territory, in which the utility would be given an exclusive right to provide electricity service. That monopoly is enshrined in law in Kansas.[3]

While utilities were granted monopolies in their service territories, it was universally recognized that there would have to be some check on their rate-setting ability. Otherwise, utilities would have unfettered power to price an essential service. A number of different oversight models developed in various localities and states across the United States. In nearly all cases, a utility's rates are subject to independent review, either by an independent regulator, or, as in the cases of public power or electric cooperatives, by officials accountable to the customers being served.[4]

Regardless of the oversight model chosen, there are several key ratemaking principles

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[2] Because of the high fixed costs and economies of scale associated with electric generation, it was long considered to be a natural monopoly. However, as noted elsewhere in this report, the generation and energy services/retail sales segments of the industry are increasingly regarded as outside of the scope of natural monopoly and contestable, but that recognition changes nothing in terms of the obligations incumbent on a distributor of electricity to incur fixed and capacity costs to meet its obligation to serve.

[3] *See* Retail Electric Suppliers Act, K.S.A. 66-1,170, *et seq.*

[4] *See, e.g.*, https://mitei.mit.edu/system/files/Electric_Grid_8_Utility_Regulation.pdf.

that apply to utilities. One such principle is the obligation to serve. Unlike other businesses, which are free to decide the appropriate level of investment to take on or what volume of business they choose to provide, utilities are required to meet all demand for electric service in their service territory at any given time, and must invest accordingly.[5] It is generally not acceptable for a utility to be unable to deliver electricity, no matter how hot the summer day or how extreme the demand. Therefore, utilities must charge rates that allow them to serve customers even when demand is highest. Typically, utility rates are determined based on the principle of providing a reasonable opportunity to earn revenue that recovers costs that were prudently incurred and necessary for the provision of safe and reliable service. In addition, because of the capital-intensive nature of the industry, rates must also include a return sufficient to attract capital to finance additional investments where needed.

In his seminal 1961 book on utility ratemaking, the economist James Bonbright,[6] whose writings on the subject are widely regarded as authoritative, suggested that rate structures should meet criteria that can be consolidated and summarized into the following three main categories[7]:

Adequate cost recovery. Providing returns that enable the recovery of investment costs, including the cost of capital;

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[5] Utilities also make these decisions in an entirely different context than unregulated businesses. The profits of regulated utilities (especially so in the case of public power) are capped by regulation, while unregulated companies face no such constraint on their potential gain.

[6] Bonbright, who died in 1993, was a long time member of the Business School Faculty at Columbia University and served for some time as Chairman of the New York Power Authority. He is widely regarded as one of the nation's most distinguished writers and commentators on regulations and a most important thought leader on the subject.

[7] "Principles of Public Utility Rates" by James C. Bonbright, first published by the Columbia University Press in 1961, p. 262. Authorized reproduction available online at http://media.terry.uga.edu/documents/exec_ed/bonbright/principles_of_public_utility_rates.pdf.

Fairness. Apportioning costs fairly among customers within a class and between customer classes; and

Efficiency. Promoting "optimum use." That is, rates should be "designed to discourage the wasteful use of public utility services while promoting all use that is economically justified in view of the relationships between costs incurred and benefits received."[8] This principle ties back into the notion of cost recovery because economically efficient rates are, by definition, tied to costs. In particular, where a utility is pricing below its costs, customers will use electricity in amounts greater than they would if they paid full cost.[9]

Cost-based rates

Bonbright posits that cost recovery, fairness, and efficiency are most easily reconciled by setting rates based on the cost of service.[10] Writes Bonbright:

> *[O]ne standard of reasonable rates can fairly be said to outrank all others in the importance attached to it by experts and by public opinion alike—the standard of cost of service, often qualified by the stipulation that the relevant cost is necessary cost or cost reasonably or prudently incurred.*[11]

In implementing "cost of service" ratemaking, ratemaking bodies typically follow a two-step process: 1) determining the utility's total costs—including a fair rate of return on capital investments, and 2) setting rates by allocating a share of those costs to different classes of customers and then selecting rate structures to recover sufficient revenue from each class of

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[8] Bonbright, op. cit., p. 292.
[9] Ahmad Faruqui Affidavit in Kansas Generic Docket on Distributed Generation Rate Design, March 17th 2017, Section III.
[10] This view is generally held by others as well. *See, e.g.*, https://mitei.mit.edu/system/files/Electric_Grid_8_Utility_Regulation.pdf Add cites.
[11] Bonbright, op. cit., p. 67.

customer.

Costs incurred by electric utilities to provide service fall into three broad categories. Variable energy costs are those directly related to the total number of kilowatt hours (kWh) used. Demand costs are the costs associated with the total capacity (kilowatts, or KW) the utility must build and maintain in order to meet peak demand. Demand costs are incurred to build generation, transmission, and distribution adequate to supply all the power needed at the moment of the very highest demand (keeping in mind that the obligation to serve is unlimited—it is generally not acceptable for a utility to "sell out" of electricity). Fixed or "customer" costs are costs that must be incurred regardless of kWh usage or KW demand. Fixed costs are typically costs that are unaffected by individual customers' changes in energy consumption. Examples include costs associated with customer service operations, such as metering, billing and customer care.

Once costs are determined, the ratemaking body must then allocate costs to classes of customers pursuant to a rate structure. This is typically done by examining the contribution of customer classes to load profiles, peak demand and connection voltage, among other characteristics. All customers are typically charged rates with at least some volumetric component. Beyond that, rates for customer classes recover costs in many different ways.

For residential customers, however, those three separate kinds of costs have traditionally been bundled together into two-part rates, consisting of a monthly fixed charge[12] and an energy

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[12] Traditionally, the fixed charge on the bill of a residential customer represents only a fraction of the utility's fixed costs. The bulk of the fixed costs and all of the demand costs are typically recovered through volumetric based rates (i.e. on a per kWh basis). The volumetric

charge (based on total kilowatt hours used). Commercial and industrial (C&I) utility customers, in contrast, have long been subject to three part rates, corresponding to the three types of utility costs. Thus, rates for a commercial or industrial customer typically include a fixed charge and two variable charges—an energy charge, based on total kilowatt hours used, and a demand charge, based on how much capacity the utility needs to maintain to meet the customer's peak demand (measured in kilowatts).[13] Accordingly, C&I customers are not only positioned to reduce both system costs and their own costs by getting a discrete demand price signal, but because that signal is provided in the rate structure, new market entrants with the capability of managing demand costs can enter the market and provide such demand management services.

Factors in the development of residential utility rates

Until recently, residential rates have generally not been as sophisticated as three-part commercial and industrial rates.[14] The primary reason residential customers did not get the same types of price signals regarding demand was due to technological limitations. Residential meters have traditionally recorded only a total quantity of kWh used over the course of the month. To do so, they could only do three things: run forward, run backward, or stand still.

Thus, meters installed in homes were incapable of accurately measuring demand over a particular interval and also incapable of communicating this information back to the utility, or

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charge is developed based on the class load profile.

[13] It is interesting that when talking about the forces that likely would prompt a utility to adopt a demand charge for industrial customers, Bonbright calls out distorting effects caused by industrial customers who provide some of their own generation. (Bonbright, *op. cit.*, pp. 309-311))

[14]All three types of costs, however, have always been passed on to customers.

even to the customer on a real time basis. Similarly, the types of products and services that enable customers to manage their demand were not widely available.[15]

The technological limitations that were a primary driver of current residential retail rate design have largely disappeared. "Smart meters," as well as internet-based technology, are capable of measuring not only how much electricity consumers use in a month, but also when they use it. As a result, utilities are now able to provide their customers with very discrete and transparent price signals that enable them to take actions that have the potential to substantially reduce the cost of service. In particular, many utilities have implemented time of use or other time-sensitive rates as at least an option for residential customers. This has generally represented an improvement in the ability of rates to reflect actual costs, since it has enabled utilities to charge a higher per kilowatt hour rate for energy consumed during peak hours, when the cost of energy production is higher.

According to analysis by Ahmad Faruqui, more than thirty utilities are offering three-part rates to residential customers.[16] These rates provide improved price signals to residential customers and encourage customers on the rate plans to manage their usage and demand more efficiently.

The traditional residential rate design did have certain advantages. Namely, it

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[15] Residential demand charges have been offered on a limited basis to customers for a long time, and historically have required the installation of a demand meter. Westar's residential demand rate is one example. Old metering technology was a barrier to adoption, and that barrier is being removed.

[16] Ahmad Faruqui Affidavit in Kansas Generic Docket on Distributed Generation Rate Design, March 17th 2017, Appendix D.

discouraged energy use, because the per kilowatt hour rate was high, and it was very simple. These volumetric rates also worked out such that utilities were able to meet their cost recovery objectives from residential customers.

However, these rates did nothing to minimize peak residential demand. Accordingly, utilities met their obligation to satisfy peak demands through a combination of large baseload plants which ran almost continuously, intermediate plants, and "peaker" plants with higher energy production costs to meet peak demand spikes, passing on the additional costs to customers through higher overall per kWh rates. The rate structure itself did little to encourage efficient energy usage at periods of peak demand, because the information concerning the true costs of peak energy delivery were not communicated to customers through the rate design.

Evolution of the Industry

The electricity industry has been changing quite rapidly. The first area of change has been in generation, which itself can be thought of as having three components: energy, capacity, and ancillary services. Energy is, with some exceptions, priced according to bids submitted by generators.[17] The second component of generation, capacity (namely, the ability to provide energy when called upon to do so) is quite important, as electricity markets, unlike perhaps any other markets, require that supply and demand be instantaneously matched. In order to perform that function, sufficient capacity, both active and reserve, is absolutely essential in avoiding

[17] Power plants are dispatched in ascending order of prices bid (i.e. lowest priced first). In markets where generators do not bid in prices, dispatch is based on costs, so lowest cost plant goes first. In both cases, that merit order of dispatch can be disrupted based on security constraints (i.e. if the merit order dispatch, would, for one reason or another, lead to overloading a particular line). In the Southwest Power Pool where Kansas utilities operate, dispatch is based on prices bid.

curtailment of service in the event of disruptions to generators or the network. Thus, generators are compensated for merely being there to generate if called upon to do so, and failure to be able to produce energy when asked to do so is subject to consequential liabilities. The third aspect of generation relates to the provision of services, known as “ancillary services” in the industry, which include a variety of functions that are essential for the reliable and efficient operation the grid.[18]

The other area of major change is retail sales, not only of energy (many parts of the country, including Kansas, do not allow for retail competition in energy sales), but also sales of goods and services that help customers to reduce their own electricity costs by managing their demand for energy and capacity more efficiently and/or allowing customers to generate some or all of the service required.[19] Distributed generation, such as rooftop solar, is both a source of energy production and a means by which customers can manage some part of their own energy supply and cost. To optimize efficient allocation of resources (including money) and value, appropriate pricing and efficient price signals for both the competing resources and for the basic network functions is critical.

Not only has the industry become far more diverse in both the generation sector and in consumer sales and services, but it has also seen the emergence of a broader base of different energy resources and major technology improvements in grid operations and measuring energy use. In terms of generation, the industry has evolved from being dominated by coal-fired thermal

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[18] Examples of such services include voltage support, reactive power, and black start.

[19] Rooftop solar is one example of self-generation, but in terms of energy efficiency capabilities, there are many. Other examples include smart thermostats like Nest, load controllers, controllable electric water heaters, and battery storage.

plants to a new situation in which the dominant fuel source for new thermal plants is now natural gas. While nuclear and hydro generators retain a significant market share, albeit less than coal-fired thermal generators, the biggest *growth* in terms of energy sources (taken together) has been in generators powered by the wind and sun.[20]

The new solar sources of generation are of two main types, large scale (sometimes referred to as "utility scale," a term which refers to the size of the facility, not necessarily its ownership) and, of course, rooftop solar. Utility scale solar generation is often connected to the utility's high voltage transmission system. Rooftop solar is incorporated into the distribution system. (Community solar is an increasingly common third type of solar generation, generally larger-scale than rooftop solar, but connected to the distribution grid.). While the distinction between the two types of solar is important,[21] it is critical to point out that, unlike fossil fuel thermal and nuclear units, which are, subject to maintenance, system constraints, and unanticipated events, operational when called upon ("dispatchable")[22], renewable solar generation is an intermittent resource. This means that it is only available when the sun is shining[23]. And even then, rooftop solar production generally increases the scale of what is

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[20] EIA, "Wind adds the most electric generation capacity in 2015, followed by natural gas and solar," *Today in Energy* web page (March 23, 2016): **http://www.eia.gov/todayinenergy/detail.cfm?id=25492**.

[21] Notably, the pricing for the two types of solar energy is so substantially different that the competitive balance is skewed heavily in favor of rooftop solar. Remarkably, that favoritism actually makes the less efficient resource, rooftop solar, more financially attractive than the far more efficient large scale solar (indeed, than wind energy as well, which is also primarily connected to the transmission grid). The reforms proposed here are well designed to level the competitive playing field, so the competition is based on efficiency and productivity and not on arbitrary or inadvertent technology choices.

[22] Fossil and other plants with capacity obligations, should they fail to meet them, are subject to liabilities related to replacement costs, if not more severe penalties.

[23] It should be noted that while both large scale and distributed solar are capable of

known as the "duck curve," beyond what is the result of large-scale solar production. Briefly stated, the "duck curve" refers to the phenomenon by which solar generates large amounts of power in the middle of the day, but as solar production declines throughout the afternoon as demand for electricity rises, the corresponding increase in demand must be met by other generation supplied or procured by the utility.[24] The "duck curve" phenomenon is illustrated in the chart below, in which the belly of the duck shows the increasingly steep drop off and ramp up of net load that is occurring and expected to increase with greater adoption of solar generation.

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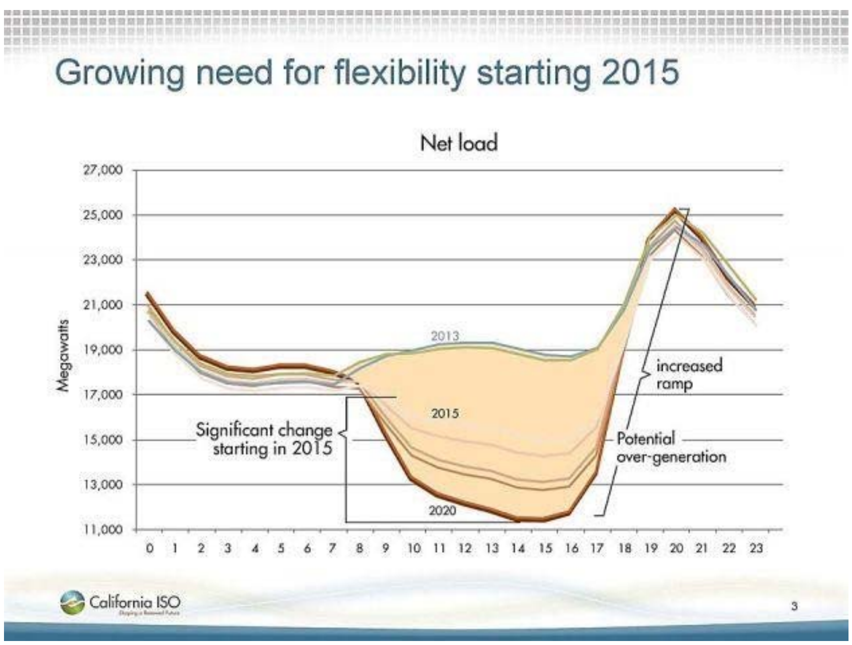
providing energy only when the sun is shining, energy from rooftop solar to the system as a whole, unlike large scale solar, is subject to still a second level of intermittency. The second contingency for deliverability to the system of energy output for system supply is completely dependent on how much of the solar panel's output is not consumed on premises. The solar host has first call on the energy produced on the customer's premises. While the demand and energy benefits to solar customers are clear, it is highly improbable that non-solar customers will benefit to the same degree.

[24] **http://instituteforenergyresearch.org/solar-energys-duck-curve/**; https://www.caiso.com/Documents/FlexibleResourcesHelpRenewables_FastFacts.pdf

As is dramatically illustrated in the graph, enticed by a number of factors, not the least of which is net metering, substantial investment in the growth of solar capacity in California has enormously magnified the need for additional fossil plants, operating on a ramping basis, to compensate for the drop off in solar production at peak. In that context, the absence of any meaningful signal to make solar more efficient (e.g., directing solar panels to the west, or linking



solar production with storage) is simply something that can no longer be tolerated.[25] While

[25] For further discussion of the implications of the duck curve, see *What the duck curve tells us about managing a green grid*, CAISO, 2013 (http://www.caiso.com/Documents/FlexibleResourcesHelpRenewables_FastFacts.pdf.)

Kansas's situation is not identical to California's, it would be pure folly for the state not to learn the lesson of what has gone wrong in other jurisdictions and adopt a remedy before it finds itself in a similar dilemma.

Intermittent sources of generation add additional complexity and cost to maintaining the high degree of reliability required of the system. This is particularly true because the distribution system was designed to accommodate one-way delivery of electricity, not the two-way exchange associated with rooftop solar generation.[26] Thus, when rooftop solar penetration increases beyond minimal levels, new investments to the grid are required.[27]

Maintaining reliability on a distribution system, particularly where market penetration of rooftop solar has increased significantly, is far more than an engineering challenge. It requires a substantial investment in more modern control and monitoring technology, as well as a substantial rethinking of pricing and the incentives produced from the economic signal produced, in order to move the entire system in directions that will best accommodate all of the changes in the power sector, particularly those related to the increasing deployment of intermittent generating facilities.

Fortunately, there have been enormous improvements in technology that, if applied

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[26] The two-way flow, particularly since the energy inputs to the distribution system are from diverse and unpredictable places, can fundamentally alter grid dynamics by impacting such critical elements as voltage support and reactive power. Since location of solar units can be a critical element in how these grid phenomena play out, the inability to plan locations for solar distributed generation, almost inevitably drives up utility costs in accommodating distributed solar.

[27] Energy Initiative, Massachusetts Institute of Technology. *The Future of Solar Energy*. Cambridge: MIT (2015): xviii. Available online at: **https://mitei.mit.edu/system/files/MIT%20Future%20of%20Solar%20Energy%20Study_compressed.pdf**.

properly, will enable utilities and their customers to meet that challenge. Metering technology, for example, has substantially advanced.

Where does distributed solar generation fit in this picture?

The initial connection of rooftop solar systems to the grid poses an issue for utilities and regulators. If customers supply power to the grid, how should they be compensated? When rooftop solar systems were first connected to the grid in the 1980s and 1990s, most households had a single meter capable only of running forwards, backwards, and standing still, and utilities and their ratemaking authorities had limited options. Given the very limited amount of rooftop solar market penetration anticipated at the time, large scale investment in new technology or overall tariff reform was not a priority.[28] Many utilities adopted retail net metering (RNM) (the term "retail net metering" is more accurate than "net energy metering," because, as discussed below, retail net metering includes many non-energy costs). Under a retail net metering tariff, a single meter for these customers runs forward when solar PV DG customers are purchasing energy from the grid. When those customers produce energy and consume it on premises, with production and consumption exactly balanced (which is highly unlikely), the meter simply stops, and when the customer produces more energy than is consumed on premises, the meter runs backwards as the excess energy is exported to the grid. Thus, the rooftop solar customer pays full retail price for all energy taken off the grid, pays nothing for energy (or demand and fixed costs incurred by the utility to stand by ready to serve, such as distribution, transmission, and generating capacity, as well as customer costs not covered in the small fixed monthly charge)

[28] Indeed, some utilities, trying to avoid the issue altogether, simply refused to interconnect rooftop solar units to the grid at all.

when energy is being produced on premises, and is credited for all kilowatt hours exported into the system, with the promise that the same number of kilowatt hours can be used by the customer for free in the future. At the end of whatever period is specified, the meter is read and the customer either pays the net balance due or the utility credits the customer for excess energy delivered. The netting occurs without regard to the time of day at which the energy is produced or consumed. It is also, in most cases, made without regard to the fixed and demand costs that are incurred to provide service – including standby service – to the solar host.

Retail net metering was put into effect when market penetration of rooftop solar was negligible, when rooftop solar systems were far more expensive than they are today, when metering technology was relatively primitive, and when wholesale energy and capacity markets did not generate the very sophisticated and unbundled signals they do today. Moreover, to the extent that any policy considerations contributed to its adoption, it was that RNM would provide a short-term stimulus to the development of distributed solar technology, not that it was sustainable as a long-term pricing methodology.[29]

What's wrong with retail net metering?

Through RNM, solar customers have until recently had the same residential tariffs applicable to them as were applied to non-solar residential customers (adapted, of course, to give credit for solar production). However, traditional residential tariffs (i.e., volumetric rates based on kWh), when applied to customers with solar generation, do a markedly worse job of reflecting actual customer costs than they do when applied to other customers. That is to say, the cost of

[29] While the full effects of retail net metering were unknown at the time of their adoptions, many jurisdictions, just to be cautious about the unknown, actually hedged against severe distortions by capping the amount of rooftop solar that would be on an RNM tariff.

serving rooftop solar customers as a class is greater than the revenue that utilities recover from such customers.

As distributed solar penetration has grown, the results yielded by RNM have become unsustainable from a pricing perspective—these results include poor price signals and "cost shifts" to customers who bear no responsibility for incurring the costs, and who are, in the aggregate, less affluent than solar customers. This is because traditional rate plans use volumetric rates to recover both fixed and demand costs. Customers who generate their own electricity use less electricity, but the fixed costs of service still exist, and the demand costs are largely unabated.

The result of linking RNM with a purely volumetric rate structure constitutes a subsidy to rooftop solar customers. The costs of that subsidy are borne by the rest of the utility's non-DG customers.

This subsidy does not exist for the majority of residential customers – those who take all of their electricity requirements from the serving utility – because they are paying for the fixed, demand, and variable costs whenever they consume energy. Because they take all their electricity requirements from the utility, peak demand (measured in KW) and overall kWh usage of non-solar, full requirements customers generally vary together. Therefore, in the aggregate, the rates non-solar, full requirements customers pay capture the costs they impose on the system. (This is true for customers who invest in energy efficiency, as well as other customers).

For solar DG customers, however, because they are only partial requirements customers, the traditional relationship between peak demand (KW) and overall kWh usage breaks down. Solar customers, by producing some of their own energy, reduce their overall kWh energy consumption from the system, often quite significantly. However, since solar generation is, to a very large degree, non-coincident with peak demand, the fact that solar customers have solar panels on their roof does almost nothing to reduce their demands on the system at peak. It also means that solar customers, when their panels are producing energy, are not paying any of the fixed costs required to enable the utility to maintain its full capability of supplying and delivering energy at whatever time the solar customer demands it. In effect, the solar customer gets a free battery and receives that battery without doing anything to reduce the overall demand on the system, all compliments of the non-solar customers.

RNM encourages behavior that exacerbates this issue. For example, under RNM, rooftop solar customers will generally receive the most savings by installing south facing panels. This orientation maximizes total kWh produced to take advantage of the retail rate credit, but produces less energy at peak demand hours late in the day (as opposed to panels installed facing west). Thus, a customer who works outside the home and uses air conditioning in the evening during the hot summer months might well offset many (if not all) of his or her kWh of usage through robust rooftop generation. However, such a customer might impose a significant peak demand load on the grid when he or she arrives home at 6 or 7 pm, when solar production is at or near zero, by turning on air conditioning and other electric appliances. In fact, the savings from solar electricity might even encourage such a user to use more peak electricity than he or she otherwise would—keeping the house a little cooler, or otherwise being freer with his or her energy use. Indeed, one of the leading firms in the business puts forward marketing materials that promote this type of expensive, highly inefficient use of energy.[30]

In short, while a two part rate, consisting of a fixed charge and a volumetric charge, is imperfect but workable for most users, it is seriously flawed for distributed solar generation users, especially in the context of increased market penetration by solar DG. The problems this causes are growing, and utilities in many jurisdictions, as well as regulators and policy makers, are struggling to reach a better rate solution.

For rooftop solar customers on RNM, especially when it is tied to two part residential rates where many fixed costs are covered through the variable portion of the rate, as is true in Kansas, this results in a breakdown in all of Bonbright's rate design criteria as summarized earlier: cost recovery, fairness, and efficiency. I discuss each of these breakdowns below, concluding with two additional problems not considered by Bonbright but created by an RNM rate—the problem of anti-competitiveness and the problem that the over-investment in rooftop solar encouraged by RNM increases the overall cost of the utility's provision of electricity service.

Retail Net Metering Problem #1: Inadequate Recovery of Costs

Under retail net metering that is tied to two part residential rates, customers with distributed solar generation experience bill reductions significantly in excess of the savings to other customers resulting from distributed energy production.

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[30] A SolarCity advertisement encourages just this behavior: "Go ahead," it reads. "Sleep with the lights on. Solar energy is limitless." https://mobile.twitter.com/solarcity/status/731167148882690048**.** This advertisement is particularly irresponsible because solar power is not generated at night.

The fact that those customers produce energy when the sun is shining does nothing to reduce the utility's fixed per-customer costs and, at least in the short run, has not been reliably shown to reduce the capacity costs the utility must incur in order to make sure that it is prepared to meet all of the electric requirements of its customers, including solar customers. Recognizing solar is not dispatchable, SPP assigns a very small capacity rating to solar, which does little to offset Westar's SPP-imposed reserve requirements. Thus, when solar DG customers are producing energy and not buying it, the utility cannot fully offset the revenue loss by simply buying or producing less energy. Consequently, the utility has a revenue shortfall, violating the criterion that a rate should provide "fair return"[31] for necessary utility expenditures and investments.

Rooftop solar generation does not significantly offset a utility's capacity costs for two reasons. The first is that solar production is often not coincident with system-wide peak demand. The second reason is that even if solar production generally matched the time when demand was projected to be at its peak, solar production is intermittent, unpredictably so, and not dispatchable by the grid operator (i.e., the grid operator cannot call upon it to produce to meet peak demand or stop producing when there are system constraints or costs requiring it). For a utility that is required to meet all the electricity demand of customers in its service territory and must meet power pool capacity reserve requirements, like Westar, the existence of rooftop solar therefore does little to avoid the need to incur the costs of meeting all demand (and little to reduce the utility's capacity reserve requirements) and, in effect, providing free back up service to solar customers.

[31] Bonbright, 293- 294.

Rates with demand charges can help address this anomaly. As a 2014 paper by the Rocky Mountain Institute (RMI) observed:

> *Separating energy and capacity charges offers several benefits . . . A demand charge creates an incentive to add combinations of DERs that more evenly spread use throughout the day, thereby lowering the impact and cost on the system. When a customer with a demand charge is also a net metered customer, the demand charge is not avoided by excess generation credits, resulting in better cost recovery for the capacity required to support some DERs. A demand charge also begins to reduce intra-class cross subsidies created between customers with different load factors.*[32]

Some advocates of retail net metering call for "value of solar" analyses, in order to claim that additional non-energy attributes of distributed solar generation add substantially to the value provided by solar DG to the utility and other customers. As a result, they argue, concerns about cross-subsidies to solar customers are misplaced. These arguments are discussed in more detail below. However, in order to believe that such cross subsidies among customers are cancelled out by the "value of solar," one would need to believe that the "value of solar" supplied is, ascertainably and quantitatively, worth an amount well in excess of the price of energy in the wholesale market at the time the energy is produced. For example, in the case of Westar, 73% of costs (excluding transmission costs) are not directly related to marginal purchases of generation.[33]

Retail net metering problem #2: Unfairness

The consequence of the re-allocation of the responsibility for costs is that net metering

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[32] Rocky Mountain Institute, Rate Design for the Distribution Edge: Electricity Pricing for a Distributed Energy Future, August, 2014. Available at: http://www.rmi.org/elab_rate_design.

[33] Direct Testimony of Dr. H. Edwin Overcast, KCC Docket No. 15-WSEE-115-RTS.

results in a subsidy from customers without rooftop solar systems to those with solar.

These subsidies associated with retail net metering are particularly hard to defend because, in the aggregate, they benefit wealthier customers at the expense of less affluent customers.[34] Less affluent customers lack the means to invest in solar and often are tenants rather than homeowners, so they are unable to install solar, even if they could afford to do so. This gap is exacerbated by the practices of rooftop solar providers like SolarCity, which offer a lease model for customers without the cash to buy a whole system up front—but the lease product is only available to customers who meet minimum credit requirements.[35]

In addition, RNM encourages rooftop solar providers to "cherry-pick" high-income, high-energy usage customers—a phenomenon also known as cream-skimming. A 2013 study by E3 Consulting supports this conclusion. The study found that the median income of rooftop solar customers under RNM was 168% of the median California household income.[36] A similar analysis of rooftop solar customers in California by Professor Severin Borenstein of the University of California at Berkeley also found installations "heavily skewed towards the wealthy" (though he noted some improvement in more recent years).[37] Organizations representing low income customers recently won their case seeking relief from having to

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[34] These subsidies are caused entirely by inadvertent consequences of the poor rate design implicit in RNM, and are certainly not the result of any public policy decisions or review.

[35] The idea of lowering credit requirements was raised by SolarCity, but there are no immediate plans for doing so: http://www.reuters.com/article/us-solarcity-fico-idUSKCN0T82ZO20151119.

[36] *California Net Energy Metering Ratepayer Impacts Evaluation.* Prepared for the California Public Utilities Commission by Energy and Environmental Economics (October 8, 2013).

[37] Borenstein, Severin. "Private Net Benefits of Residential Solar PV: The Role of Electricity Tariffs, Tax Incentives and Rebates." Energy Institute at Haas working Paper. 2015: 26. Paper available online at http://ei.haas.berkeley.edu/research/papers/WP259.pdf.

subsidize rooftop solar customers in Massachusetts.[38]

Retail net metering problem #3: Inefficiency

RNM also fails to promote efficient use of the electricity generated by distributed solar. Because the costs of peak demand on the system are not reflected in their rates, customers with distributed solar are motivated to produce as many kWh as possible, but not necessarily to target production or manage demand to offset peak consumption.

One example of this problem, noted above, has to do with the orientation of rooftop solar panels. The monetary value of energy provided to the grid varies depending on the time of day. Generally speaking, energy provided at the time of peak usage is the most valuable. That is because the generating fleet is dispatched on the basis that the least expensive plants are generally dispatched first. As demand increases, of course, more and more expensive plants are dispatched until all demand is met.[39] However, RNM provides one signal to customers with solar DG systems—the more you produce, the more you are paid, regardless of the energy market prices at the time of production.[40] For this reason, as a *New York Times* article explains, flat RNM pricing has contributed to solar panels generally being installed facing south, to generate the largest total quantity of solar energy over the course of the day (and the greatest

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[38] Petition of the Low-Income Weatherization and Fuel Assistance Program Network to Apply G.L. c. 164, sec. 141, submitted to the Commonwealth of Massachusetts Department of Public Utilities, November 17, 2015. For decision, see DPU 15-155.

[39] It is worth noting that, in general, the economic order to dispatch power plants also has a salutary environmental effect. That is because, in general, the least expensive plants are either non-emitting of pollutants (e.g. renewables), or low emitting, more efficient plants.

[40] Energy prices in the electricity market, as one might expect when supply and demand have to be instantaneously matched, vary widely over the course of every day. Thus the time at which energy is produced is a critical determinant of the price suppliers are paid. RNM ignores that market place reality and, under RNM, fetches an above market price for solar DG output that is exported onto the grid.

savings and/or revenue for homeowners under RNM). If solar rates instead reflected the cost to the grid of the customer's period of highest demand, these panels would be adjusted to capture the most sun during peak hours—for many customers, this would mean aligning panels to face west, generating less total energy, but capturing the late afternoon power of the setting sun.[41] Thus, RNM incentivizes production in ways that are optimized for the DG solar industry and its customers, not to the system and non-solar customers.

In a well-functioning market with proper price signals, such a misalignment of incentives would cease to exist, but RNM runs contrary to ordinary market functions and substantially distorts pricing in ways that are misaligned with efficiency.

RNM also discourages the adoption of batteries or other forms of storage in conjunction with rooftop solar production. This is because, under an RNM tariff, the utility operates essentially as a giant free virtual battery available for use by DG solar customers. Any excess energy DG solar customers produce is credited at the full retail rate, and such customers can import an equivalent amount of energy back from the grid at any time at no charge. While at first blush that might seem reasonable, it is not sustainable. While there may be some material overlap between solar output and peak demand, that value is substantially diminished by the fact that the availability of the solar output is subject to climatic fluctuations and the demand characteristics of customer premises. So, to the extent to which there is coincidence, it is almost immaterial. Moreover, a RNM customer's arrangement with the utility is netted out at the end of the billing cycle without regard to the real-time economics of the market. The end result is not

[41] Matthew L. Wald. "How Grid Efficiency Went South" *New York Times*. October 7, 2014.

reflective of either actual costs or market realities.[42]

What this unjustified RNM “swap” means is that DG customers, who would seem to be a natural customer base for energy efficiency and/or capacity savings devices or storage batteries available on the market to better align their energy and capacity demand with system costs, have, under RNM, no incentives to invest in such products, therefore delaying the development of the integrated solar/battery home systems that may be a logical next step for distributed generation. That may be why, for example, Tesla—Solar City’s own previous sister company, run by SolarCity’s Chairman Elon Musk, and now its parent company —reportedly opposes RNM.[43] As SolarCity concedes, RNM removes an incentive for residential customers to deploy batteries and other forms of energy storage.

By contrast, a demand charge provides a price signal that makes it in the interest of solar customers to invest in technology that will improve the reliability of their energy supply and better serve the energy and capacity needs of the system. This distinction is well illustrated by the fact that commercial customers are typically subject to demand charges and, correspondingly,

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[42] Another way to think about this transaction is as a poorly-designed energy swap, in which the utility assumes all of the risk and gets nothing in return (usually, the purpose of a swap is to decrease risk). In marked contrast to an energy swap that might result from a negotiation in a competitive market, this swap requires the utility to (1) absorb any difference between the price of the energy at the time it receives it from the RNM customer and the cost of the energy the utility must produce or purchase when the RNM customer exercises its right to “call”; (2) absorb any differences in product type and the cost or value of what is supplied and what is delivered (i.e., the difference between unscheduled energy-only delivery by the RNM customer and the whole on-demand package of energy, ancillary services, transmission service and distribution services delivered by the utility); and (3) absorb (all administrative costs associated with the swap. If this swap transaction was anything other than RNM mandated, both FERC and the state commissions would be warranted in declaring it imprudent.

[43] “Net Metering vs. Storage Creates Clash Between Some Allies.” http://www.eenews.net/stories/1060025111

have adopted solar in conjunction with peak shifting and peak shaving technologies. Indeed, SolarCity heavily markets its demand-shifting technology, which includes battery storage and its DemandLogic product, but only does so for its commercial customers. There is no reason that this technology would not work for residential customers. However, SolarCity offers this technology to commercial customers only, because those have traditionally been the only customers subject to a demand charge.

To make matters worse, it appears that the solar installation market is currently such that generous subsidies provided through programs like RNM do not get fully translated into reduced customer costs. The recent MIT study, *The Future of Solar Energy,* observes a "striking differential" between MIT's estimate of the cost of installing residential PV systems (even allowing for a profit margin) and the reported average prices for residential PV systems—actual prices for residential systems were approximately 150% of MIT's cost estimate—a difference between cost and price the MIT researchers did not observe for utility-scale installations.[44] Indeed, as documented in the MIT study, there is evidence now that the declining costs of solar panels, which have been quite dramatic in recent years, are not being passed through to consumers, enabling most of the benefits of declining panel costs to be retained by solar vendors, to the detriment of all consumers, solar and non-solar alike.

This adverse effect, of course, is spread even further to non-solar customers because of RNM's inherent wealth transfer. A recent study by Lawrence Berkeley National Labs found that out of four countries it compared to the U.S. (Germany, Japan, France, and Australia), the U.S.

[44] MIT, The Future of Solar, p. 86. Of course, utility owned solar facilities are subject to cost-based ratemaking practices that ensure that cost reductions in solar are reflected in rates to utility customers.

had the highest prices (per watt of capacity) for installed residential PV systems.[45] The reasons for these high U.S. prices are not fully understood—it is something more than market size, since the U.S. market is smaller than the solar pv market in some of the four other countries studied, but larger than others. A 2014 study aimed at better understanding variations in solar pv pricing, involving collaboration between researchers from Yale, Lawrence Berkeley National Laboratory, the University of Wisconsin at Madison, and the University of Texas at Austin, found a revealing association:

> *…regions with a higher consumer value of solar, considering retail electricity prices, solar insolation levels [author comment: that is, the amount of sunshine], and incentives, tend to face higher prices. This phenomenon may be the result of a shift in consumer demand caused by the presence of rich incentives, enabling entry by higher-cost installers and allowing for higher-cost systems. Alternatively, the results may be a symptom of high information search costs or otherwise imperfect competitions, whereby installers in these markets are able to "value price" their systems, effectively retaining some portion of the incentive offered…In the short-run at least, policies that stimulate demand for PV may have the exact opposite of their intended effect, by causing prices to go up rather than down.*[46]

That is, RNM, by effectively shielding rooftop solar suppliers, from both robust competition and from cost-based regulation, may be removing a key incentive for rooftop solar installation companies to pass on declining costs to customers.[47]

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[45] Barbose, Galen and Naim Darghouth. Tracking the Sun IX: The Installed Price of Residential and Non-Residential Photovoltaic Systems in the United States. Lawrence Berkeley National Laboratory (August 2016):22-23.

[46] Gillingham, Kenneth, Hao Deng, Ryan Wiser, Naim Darghouth, Gregory Nemet, Galen Barbose, Varun Rai, and C.G. Dong. Deconstructing Solar Photovoltaic Pricing: The Role of Market Structure, Technology, and Policy. (December 2014): 20-21. Available online at: http://www.seia.org/sites/default/files/LBNL_PV_Pricing_Final_Dec%202014.pdf

[47] The failure to pass on declining input costs to customers is pricing behavior often

As a result, RNM does not incentivize productivity or reliability. To the contrary, it harms the long term sustainability and competitiveness of the technology as a mainstream resource.

In fact, emphasizing this very point, in a recent 10K filing, SolarCity, the nation's largest solar DG company, clearly describes this as its business model:

> *We compete mainly with the retail electricity rate charged by the utilities in the markets we serve, and our strategy is to price the energy and/or services we provide and payments under MyPower below that rate. As a result, the price our customers pay varies depending on the state where the customer is located and the local utility. The price we charge also depends on customer price sensitivity, the need to offer a compelling financial benefit and the price other solar energy companies charge in the region. Our commercial rates in a given region are also typically lower than our residential rates in that region because utilities' commercial retail rates are generally lower than their residential retail rates.*[48]

From SolarCity's perspective, of course, the issue is not whether rooftop solar can be competitive, but whether it can remain so without suppliers like SolarCity having to pass on to consumers some of the cost reductions in their supply chain, something that might reduce their profit on a per transaction basis, but make solar more attractive to more customers enabling more sales. In short, SolarCity, the leading solar DG provider in the country, has a business model premised on keeping prices high in a declining cost industry, and relying on subsidies and cross-subsidies in lieu of the classic economic formulation that lower prices (in this case enabled from lower costs) stimulate demand. Stated succinctly, the business model articulated by SolarCity in

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considered to be characteristic of monopoly pricing.

[48] SolarCity Corp 10K, filed 2/24/15 for period ending 12/31/14, p. 38 (available at http://files.shareholder.com/downloads/AMDA-14LQRE/1445127011x0xS1564590-15-897/1408356/filing.pdf)

its 10K filing, and shared by those solar DG vendors who demand retail net metering, is to chase subsidies and cross-subsidies rather than to compete in the marketplace, something that would require passing on declining costs, increasing productivity, and innovation.

Retail Net Metering Problem #4: Anti-competitiveness

The failure to provide incentives to invest in efficiency-enhancing technologies points to a fourth problem with retail net metering, which does not fit neatly into Bonbright's rate criteria. This fourth problem is that retail net metering distorts the competitive market for other resources. In seeking cost-effective means of reducing their electricity bills and environmental impact, consumers have a variety of options. Rooftop solar is one possibility, but there are a variety of competing alternatives; many of them provide greater value to the grid, most notably various energy efficiency programs and means of flattening out customers' load profiles.[49] The subsidies associated with RNM, however, substantially favor rooftop solar over these other options.

Amory Lovins, of the Rocky Mountain Institute, has presented an analysis that includes data showing that solar energy (even grid-scale solar energy) is less cost-effective than energy efficiency, wind and hydro in terms of reducing carbon emissions.[50] The true test as to which demand-reduction technology is the most economically and/or environmentally efficient would be a market that allowed parties to compete to meet the end objectives of customers, and not to bias the outcome in favor of a technology that may well not be the most cost effective. The

[49] Load profile is the configuration of how much energy a customer consumes (kilowatt hours, (kWhs)) and precisely when it is consumed. The time when the demand hits its maximum defines the amount of capacity (kilowatts (kWs)) a utility must have available to serve that customer.

[50] Lovins, Amory B. "Sowing Confusion about Renewable Energy." *Forbes* August 5, 2014.

combination of RNM and volumetric pricing, however, distort that market.

RNM Problem #5: Under RNM, Rooftop Solar Makes Electricity Service More Costly Overall

Rooftop solar is the most expensive form of renewable generation with meaningful usage in the U.S. today. The latest annual update of Lazard's *Levelized Cost of Energy Analysis* continues to show this, with a levelized cost for rooftop solar ranging from $138-$222 per MWh, higher than all other energy sources analyzed (with the exception of a diesel reciprocating engine), including fuel cell, solar thermal, utility-scale solar, geothermal, biomass, and wind.[51] The Lazard analysis goes on to compare the cost of carbon abatement per ton for different alternative energy resources. As one would expect based on its levelized cost, rooftop solar power had the highest cost per ton of carbon emissions avoided ($176 per ton, assuming gas is the comparison generation). In contrast, Lazard's calculations found that utility-scale solar PV could abate the same ton of carbon emissions at a cost of only $1 per ton. The difference here is staggering.[52]

A recent study by The Brattle Group comparing generation costs of utility-scale and residential-scale PV in Colorado confirms that most of the environmental and social benefits provided by PV systems can be achieved at a much lower cost at utility-scale than at residential-

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[51] *Lazard's Levelized Cost of Energy Analysis-Version 10.0.* December 2016. Data cited is from p. 2 table, "Unsubsidized Levelized Cost of Energy Comparison." Full report available online at https://www.lazard.com/media/438038/levelized-cost-of-energy-v100.pdf

[52] *Lazard's Levelized Cost of Energy Analysis-Version 10.0.* Data cited is from p. 6 table, "Cost of Carbon Abatement Comparison." Full report available online at https://www.lazard.com/media/438038/levelized-cost-of-energy-v100.pdf

scale.[53]

In short, RNM operates to make rooftop solar more attractive than other forms of renewable generation through subsidies from non-solar utility customers. Moreover, the absence of transparent, time sensitive and, more specifically, demand-related price signals, has the effect of inhibiting market entry by service providers who can respond to those signals. A properly designed three part rate, in contrast, by making demand charges transparent, would enable providers of demand-reduction products and services to compete with SolarCity and others for the same space in the marketplace.

Current Rate Reform Initiatives

Unsurprisingly, given the problems with RNM explained above, many utilities are examining how to better structure rates for distributed generation customers. There is a robust debate occurring across the nation regarding the appropriate rate mechanisms for addressing the issues raised by distributed generation technologies, with a growing recognition throughout the United States that traditional RNM is not sustainable as a pricing methodology. For example, in 2015, 46 out of 50 states had ongoing studies, proposals, or enactments relating to "net metering, valuation of distributed solar, fixed or solar charges, third-party or utility-led rooftop solar ownership, or community solar."[54] Out of 99 energy-related actions in 42 states in the fourth quarter of 2015, the most common proposals were fixed charge increases (34), net metering

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[53] Bruce Tsuchida, Sanem Sergici, Bob Mudge, Will Gorman, Peter Fox-Penner, and Jens Schoene, "Comparative Generation Costs of Utility-Scale and Residential-Scale PV in Xcel Energy Colorado's Service Area." The Brattle Group, July 2015, p. 3.

[54] North Carolina Clean Energy Technology Center & Meister Consultants Group, "The 50 States of Solar: 2015 Policy Review and Q4 Quarterly Report," February 2016: 11. Available online at: **https://nccleantech.ncsu.edu/wp-content/uploads/50sosQ4-FINAL.pdf**

policy changes (25), solar charges (16), and state solar valuation or net metering studies (9).[55] In that same quarter, 28 legislative or regulatory actions in 17 states focused on net metering policies. These states stretched from coast to coast, including Nevada, Ohio, Pennsylvania, Virginia, Connecticut, and Maine.[56]

Turning to 2016, in the first quarter of 2016, 39 states took some action related to "net metering, rate design, and solar ownership," according to the NC Clean Energy Technology Center's report.[57] The report describes a continuing "trend" of fixed charge increase requests by utilities, with 19 such requests pending at the end of March 2016.[58] Proposed changes are often controversial. In Maine, a law that would have replaced RNM with an innovative system combining bidding, procurement targets, and long-term contracts was recently vetoed by Governor LePage, and the Commission has now adopted a plan to phase out net metering over time. Hawaii recently ended its RNM program. In Nevada, RNM reform has resulted in a boycott of the state by some major solar installers, and now may face repeal by the current Commission. Arizona's Commission has also issued an order ending RNM. Vermont has reduced the amount of its RNM subsidy. Other states which are at various stages of review and revision include not only Kansas, but also Utah, Massachusetts, Ohio, New Hampshire, Louisiana, and recently Colorado. The old national *status quo* of net metering is being reexamined in a growing number of jurisdictions across the country.

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[55] *Ibid.*, p. 38.
[56] *Ibid.*, p. 40.
[57] North Carolina Clean Energy Technology Center & Meister Consultants Group, "The 50 States of Solar: Q1 2016 Quarterly Report," April 2016: p. 9. Report available online at: https://nccleantech.ncsu.edu/wp-content/uploads/50-SoS-Q1-2016_Final.pdf
[58] *Ibid.*, p. 50.

While not every state or utility that is revising its net energy metering policy is considering demand charges, many are, and the adoption of demand charges is an idea supported by progressive environmental groups, as well as rate economists. A number of utilities outside Kansas have adopted special rate structures tailored for distributed generation customers.[59] Furthermore, in an effort to better make pricing schemes reflect true costs of service, many utilities have long offered optional demand charges for residential customers.[60] Recently, a number of utilities either have implemented or proposed implementation of a demand charge, intended to better reflect the cost of customer use of the grid.[61] Analysis by Ahmad Faruqui identifies 32 utilities in 17 states with demand charge rates for customers.[62]

Some solar and environmental advocates endorse rates for rooftop solar customers that include demand charges. Indeed, although the Rocky Mountain Institute (RMI) has taken somewhat contradictory positions on this issue, at least one blog post from the RMI, one of the

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[59] These utilities are: Alabama Power, Alaska Electric Light & Power, Arizona Public Service, Black Hills (South Dakota and Wyoming), Dominion (Virginia and North Carolina), Duke Energy (North Carolina and South Carolina), Georgia Power, and Xcel Energy (in Colorado). *See* Ahmad Faruqui & Ryan Hledik, *An Evaluation of SRP's Electric Rate Proposal for Residential Customers with Distributed Generation (Prepared for Salt River Project)*, THE BRATTLE GROUP 13 (Jan. 5, 2015), http://www.srpnet.com/prices/priceprocess/pdfx/DGRateReview.pdf.

[60] Demand charges for industrial and large commercial customers are already quite common in the U.S.

[61] Utilities that currently have non-optional demand charges for some or all customers, in addition to SRP, include Florida's Lakeland Electric and the Intermountain Rural Electric Association in Colorado. Demand charges have been proposed and are under consideration in other Arizona utilities, as well as in utilities in Illinois, Oklahoma, Nevada, California, Texas, Kansas, Oklahoma, and Montana (see *Utility Dive*, "ComEd jumps on the Demand Charge Train with New Illinois Proposal." Peter Maloney, May 9, 2016. Available online at: http://www.utilitydive.com/news/comed-jumps-on-the-demand-charge-train-with-new-illinois-proposal/418735/.

[62] Ahmad Faruqui Affidavit in Kansas Generic Docket on Distributed Generation Rate Design, March 17th 2017, Appendix D.

nation's foremost proponents of energy efficiency, hails demand charges:

> *Demand charges are a promising step in the direction of more sophisticated rate structures that incent optimal deployment and grid integration of customer-sited DERs. A demand charge more equitably charges customers for their impact on the grid, can reward DG customers with bill savings, and opens up potential for an improved customer experience using load management tools. It can also benefit all customers through reduced infrastructure investment and better integration of renewable, distributed generation.*[63]

The Natural Resources Defense Council (NRDC), like RMI, has taken divergent positions on this issue, but it is notable that in CPUC Rulemaking 14-07-002, supported demand charges for rooftop solar customers.[64] The NRDC described its position regarding why demand charges were a good fit for rooftop solar customers as follows:

> *[O]ur proposal includes a variable demand charge that would be based on the transmission and distribution grid service costs, which represent the investments that utilities have to make in order to reliably deliver service. Demand charges have been used for decades by numerous utilities to provide incentives for higher grid capacity users to manage on-site load "peakiness." We think demand charges are a good and reasonable fit for NEM [net energy metering] customers because they use existing local grid capacity for both export of their unused on-site generation and import when the on-site system cannot fully meet demand. For example, a brief passing cloud can cause a rooftop solar customer to rapidly go from exporting unused electricity to importing needed electricity from the local grid. NEM solar customers can thus create a broader capacity "swing" than non-NEM*

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[63] Lehrman, Matt. "Are Residential Demand Charges the Next Big Thing in Electricity Rate Design?" Blog Post, *RMI Outlet* (May 21, 2015) **http://blog.rmi.org/blog_2015_05_21_residential_demand_charges_next_big_thing_in_electricity_rate_design**

[64] See NRDC testimony filed in CPUC Rulemaking 14-07-002, "Proposal of The Natural Resources Defense Council (NRDC) In Determining a Net Energy Metering Successor Standard Contract or Tariff," (August 3, 2015).
http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M154/K225/154225677.PDF

> *counterparts. In keeping with the intent of NEM to be simple to administer and provide cost certainty for customers, we propose that the demand charge be assessed as part of the new NEM tariff in a manner that groups customer demand into three buckets (0-3 kW, 3-6 kW and 6 kW and above) with each bucket having an assigned monthly charge attached to it ($5, $10 and $15, respectively).*[65]

San Diego Gas & Electric likewise recently stated that RNM "customers fail to pay their fair share" of costs, and this "shortfall is shifted" to non-RNM customers.[66] SDG&E's proposal was an unbundled rate plan which, by including fixed, demand, and time of use charges, would "significantly limit cost-shift to other customers."[67]

In short, a number of market participants and observers have concluded that, as a class, RNM customers are not covering the costs that a utility incurs in serving them; that, as a result, RNM requires non-solar customers to subsidize rooftop solar customers; and that the RNM subsidy should be reconsidered.

The benefits of reformed three-part rates: Connecting costs and prices

A well designed three part rate addresses the problems of net metering discussed above. First, with respect to cost recovery, the three-part rate addresses the problem of using a

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[65] Pierre Bull, "NRDC Proposal to Evolve Net Metering in California," *NRDC Expert Blog* (August 18, 2015), available online at: **https://www.nrdc.org/experts/pierre-bull/nrdc-proposal-evolve-net-metering-california**

[66] See SDG&E testimony filed CPUC Rulemaking 14-07-002, "San Diego Gas & Electric Company (U 902 E) Reply Comments on Proposed Decision," (January 15, 2016): http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M157/K710/157710268.PDF

[67] https://www.sdge.com/sites/default/files/regulatory/Proposal_NEM_Successor_Tariff-Filing%20.pdf. The SD G&E proposal also would have provided an RNM credit at the wholesale rate, which it believed "better aligns" the costs of rooftop solar with the benefits received.

volumetric rate to recover fixed costs from rooftop solar customers and more closely aligns the prices charged to rooftop solar customers with the cost of serving them. Rather than attempting to recover charges associated with serving peak demand through a variable energy rate, a three part rate can align charges with costs. True fixed costs (billing, etc.) can be recovered through a fixed monthly charge. Costs directly related to energy use (fuel costs, or electricity purchase costs) can be recovered through a per kWh rate. And costs related to sizing transmission, distribution, and generation to meet peak demand can be recovered through a demand charge. The rate thus addresses the unfairness of retail net metering, eliminating the cross subsidies caused by the RNM-enabled avoidance of paying solar customers' fair share of fixed costs. By requiring solar customers to pay a greater share of customer related fixed costs, rates will no longer re-allocate a portion of those costs to the non-solar ratepayers. Recovering costs through a demand charge avoids socializing the costs of protecting against the unreliability of solar PV.

It may be important to note here that, while a demand charge may be a new line item on a customer's bill, it is not, in fact, a new cost imposed on customers. Customers have been paying for demand all along—a demand charge does not create a new cost; rather, it breaks it out, and makes it visible and manageable.

With respect to efficiency, by tying pricing to peak usage, the rate structure opens up the possibility of rewarding solar PV DG providers who are most successful at providing reliable energy to the grid and smoothing their own demand, whether through installing their panels so they face west rather than south, installing batteries to operate in conjunction with their generation or adjusting their own consumption patterns to reduce their demand peak and maximize the value of the energy they export to the grid. It also brings the pricing for distributed solar into much closer alignment with how energy markets actually function.

“Value of solar” claims: Does additional “value” provided by rooftop solar change the calculus in establishing rates for distributed generation/partial requirements customer?

The Commission’s direction on this docket includes the statement that “the Commission has the discretion to consider the utility’s quantifiable costs of providing service to a customer class, such as DG customers. Likewise, the Commission recognizes that quantifiable benefits of DG may decrease the utility’s cost of providing service to DG customers.” For this reason, although the Commission has determined that one of most commonly cited “values” of solar, freedom from externalities associated with pollution and CO_2, is not part of this docket, it is important to examine some of the other claims that are made of additional “value” for rooftop solar generation.

In the face of arguments like those above against retail net metering, advocates of RNM, in order to counteract opposition to cross-subsidies, have tried to develop theories as to why the obvious cross-subsidization does not occur in RNM. Their line of argument is based on what has been described as “value of solar” theory. However, value of solar calculations, far from being definitive, are part of an ongoing debate, in which there is no consensus.

Studies of the “VOS” are highly subjective and readily manipulated, because there is no established methodology for assessing the value of solar, and, furthermore, given the complexity of the analyses needed to assess all the various “VOS” claims, no analysis can effectively avoid the need to make multiple subjective judgments. Indeed, the “calculation” requires so many inputs, assumptions, estimates, etc., all of which are highly contestable, that no consensus may be possible.

Value of Solar pricing is an attempt to quantify the costs a utility avoids from rooftop solar generation. So-called "avoided cost" pricing has a history in utility regulation, and it is not a favorable one. In 1978, Congress enacted PURPA (the Public Utilities Regulatory Policies Act). Among other things, PURPA encouraged the development of alternative power, including renewable energy and cogeneration, by requiring utilities to purchase energy and capacity from "qualifying facilities" (QFs) at their incremental or avoided costs. "Avoided costs" was defined as: "[T]he incremental costs to the electric utility of electric energy or capacity or both which, but for the purchase from the QF or QFs, such utility would generate itself or purchase from another source."[68]

Efforts to calculate "avoided costs" rapidly encountered difficulties. As one article describing avoided cost pricing under PURPA observed:

> *Errors in the estimation of long-run avoided costs are inevitable. However, as PURPA was implemented by state regulators in the 1980s, a combination of questionable methods of setting avoided cost and/or poor application of these methods led to excessive avoided cost payments and forced utilities to buy QF capacity even when the utilities did not require more capacity. In addition, excessive, non-dispatchable QF output created operating problems for some utilities. Many complaints about PURPA's implementation were raised by electric utilities and others.*[69]

As was clearly demonstrated by the PURPA experience, avoided cost analysis is subject to the biases and policy predispositions of the authors and/or sponsors of such studies.

This reality is well illustrated by the extraordinarily wide variance in the conclusions of

[68] 18 CRF §292.101(b)(ii)(6) (Public Utility Regulatory Policies Act of 1978).

[69] Graves, Frank, Philip Hanser, and Greg Basheda. "PURPA: Making the Sequel Better than the Original." Prepared for the Edison Electric Institute (December 2006). Available online at http://www.eei.org/issuesandpolicy/stateregulation/Documents/purpa.pdf

VOS studies. The range is dramatic, with a VOS study in Louisiana finding a negative value, while a VOS study in Maine calculated a value of 33.7 cents/kWh.[70,71,72] Additional disagreement exists over the individual components that make up VOS analysis.

Furthermore, analyzing the "value" of rooftop solar in isolation produces an essentially meaningless number, in the absence of similar "value" analysis for all other competing resources. VOS studies are technology-specific (almost always limited to rooftop solar) and almost always ignore market conditions and how the calculated value of rooftop solar compares with the value of competing resources to meet the same objectives.

In addition, VOS studies rarely, if ever, look at the opportunity costs associated with spending money on rooftop solar, as opposed to using that money on something that produces energy and/or reduce emissions more efficiently (many other major renewable technologies, as discussed above, beat rooftop solar by these measures). This kind of one-dimensional, out-of-context analysis of an extraordinarily complex subject is almost useless as an evaluative tool.

Even a cursory analysis of the various individual elements generally offered up to

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[70] Dismukes, David E. Estimating the Impact of Net Metering on LPSC Jurisdictional Ratepayers. Prepared on behalf of the Louisiana Public Service Commission. Prepared on Behalf of Louisiana Public Service Commission Draft, February 27, 2015. Please see: **http://lpscstar.louisiana.gov/star/ViewFile.aspx?Id=f2b9ba59-eaca-4d6f-ac0b-a22b4b0600d5**.

[71] Grace, Robert C., Philip M. Gruenhagen, Benjamin Norris, Richard Perez, Karl R. Rabago, and Po-Yu Yuen. *Maine Distributed Solar Valuation Study*. Prepared for the Maine Public Utilities Commission. Revised April 14, 2015. *Please see:* **http://www.maine.gov/mpuc/electricity/elect_generation/documents/MainePUCVOS-ExecutiveSummary.pdf**.

[72] To put the 33.7 cents /kWh valuation in perspective, that number is roughly double the full retail rate of Maine's largest electric utility. In other words, the authors of that study calculated that the "value" of the energy produced by each rooftop solar installation is worth double the full delivered cost of electricity. That is the equivalent of saying that the value of a part of a product is worth double the value of the entire product.

calculate the value of solar suggests that, with the exception of avoided short-term energy costs, and perhaps, on a time and location specific basis, some savings on transmission congestion, there is little bankable value there. Few of the "values" attributed to rooftop solar stand up to scrutiny, and those that do are compensated under a three part rate, to the extent they are real.

Avoided energy costs

Rooftop solar generation, when produced, does reduce the amount of electricity the utility must provide. Almost every participant in the conversation about the "value" of solar agrees on this.[73] Caution should be exercised, however, when the suggestion is made that the value of the generation to be offset should be calculated on a "levelized" basis—projected for twenty years, and then averaged. This introduces unnecessary and unhelpful speculation about future gas prices and inflation, while doing little to illuminate how actual current cost savings should be considered.

Avoided capacity costs (generation and transmission)[74]

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[73] Many value of solar analyses present the avoided energy cost as a "levelized" number, which factors in predictions of increasing energy costs in upcoming years to come up with a "levelized" avoided energy cost which is higher than the actual energy cost today. It is tempting here to focus on the fallibility of making reliable predictions about future energy costs (look at recent trends in natural gas prices. Most people did not foresee recent declines). But the whole issue of prediction is a red herring in this context, because RNM does not provide utilities with ownership of distributed solar resources, and therefore gives it no protection against future energy price increases. If an RNM system of compensation continues, reimbursement rates will always be tied to overall energy price increases. So, costs of RNM to the utility will go up right along with savings. Trying to give solar resources credit ahead of time for rising energy costs needlessly complicates the analysis, which would then have to be balanced with appropriately rising net energy metering costs. It is simpler and less misleading to use current avoided energy costs, recognizing that these need to be updated regularly.

[74] Capacity in electricity refers to the generating resources to deliver energy when called

The idea that having a lot of distributed solar on the system means that the utility requires less capacity of various kinds is one of the commonly asserted claims made by retail net metering advocates. These claims are wrong. Solar energy is intermittent and only available when the sun is shining, and, in the case of rooftop solar, only available for export to the grid if the sun is shining and the solar customer is not using all the energy produced on his/her rooftop. Rooftop solar generation is not and cannot be relied upon to produce any energy when called upon to do so, nor to reduce demand reliably, because there is no way to be certain that the conditions necessary for rooftop solar energy to produce when asked to do so will be met.

To further contextualize the issue, most of a utility's capacity expenses are tied to sizing the grid (transmission and distribution) and procuring generation and reserves to assure the ability to meet peak demand. To realize significant savings here, solar would have to reliably reduce the peak itself—not just provide some energy during some off-peak or even some peak hours. Self-consumption by solar customers and the natural forces of weather and presence of the sun erodes solar's reliability as a peak offsetting resource, and sundown itself means that solar is coming off the grid, just as the utility reaches a peak demand hour that is shifting later and later in the day, when solar panels produce very little, if any, energy. The result is that when the rooftop units are most likely to be called upon to deliver energy, they will frequently be incapable (and will never be predictably capable), without batteries or some other means, to do so.

Additionally, unlike the wholesale market in which, when a generator obtains a capacity

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upon to do so. What is produced, of course, is energy, whereas capacity is the ability to produce when called upon to do so.

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payment, the generator agrees to either deliver the energy called for, or assumes liability for supplying replacement energy, rooftop solar providers under RNM make no such assurances. If the utility incorporates this "value" into rates, it potentially pays twice—first, in a lower rate for rooftop solar customers, and, second, if the rooftop solar producer fails to deliver, the utility must pay again, this time to an alternative supplier to provide what the solar provider did not. For the solar producer, it is, quite simply, a "heads I win, tails you lose" proposition.

Under a well-designed three part rate, capacity benefits are far more likely to be realized, since customers would be rewarded for reducing demand, a tariff that would actively encourage customers who choose to put solar systems on their rooftop to also use load shifting technology, such as storage or other load controlling devices like smart thermostats, controllable electric water heaters, and pool pumps, to levelize demand.[75]

Potential savings related to power flow: Line loss reductions and ancillary services

It is true that energy losses occur during transmission and distribution. However, whether or not solar PV systems reduce the amount of energy lost in long distance transmission and distribution is a fact-specific question, dependent on an array of variables (including the location of rooftop solar systems), and the answers may be counterintuitive. Electricity flows on wires according to laws of physics, following the course of least impedance, a natural phenomenon impacting every interconnected wire, regardless of whether the wire is sized to withstand the

[75] As a former regulator, in dealing with larger scale capacity contracts, it is my opinion that payments for capacity should depend on performance. On an individual household level, the demand charge here nicely embodies this principle.

current.[76] As a result, energy flow on the grid is highly dynamic in real time. Every injection or withdrawal of energy impacts the ability to access the grid throughout the system. Maintaining optimal grid functionality requires careful planning, vigilant and prudent dispatchers, and the ability to call upon resources to provide what are called ancillary services, such as voltage support, reactive power, black start, and other very location specific services that are essential to grid operations, many of which also affect line losses.

Thus, with respect to the distribution grid, the production or non-production of energy affects line losses on a very location- and time-specific basis. While it is true that DG can have a salutary effect on line losses, it is equally correct to say that it could have an adverse effect on line losses. As a matter of physics, there is simply no generic "value" associated with rooftop solar reducing line losses on the distribution grid.

With respect to the transmission grid, the issue is a bit different, because rooftop solar is not directly interconnected to the high voltage system. Nonetheless, rooftop solar, simply as a matter of scale, probably has very little impact on transmission line losses. Further, (here the counterintuitive interconnected properties of electricity grids come into play) there is no simple and reliable relationship whereby less power delivered to a certain location guarantees less congestion on the grid, and correspondingly fewer transmission losses. Electricity on an interconnected grid impacts the whole grid according to laws of physics that are such that

[76] The flows of the high voltage transmission system and the low voltage distribution system are separate and distinct from one another, so the flows according to least impedance are system specific. While demand shifts at any given interconnection point where high voltage is stepped down to low voltage can influence flows on the high voltage system, the actual flows between the two systems are separated by transformers, so the flows between systems are controlled.

electric energy, much like water, flows wherever resistance is least. Thus the grid is highly dynamic and every input and output has cascading effects. Thus, inputs into the grid need to be carefully balanced with withdrawals to avoid overloading any specific wire and to allow for access to the cheapest possible generation. The impact of lessening demand from a particular node on the grid depends on the specific constraints affecting dispatch at a given point in time. Just as in the case of distribution, to the extent that rooftop solar impacts transmission line losses at all, it is very location- and time- specific, so generic conclusions are simply not reliable.[77]

If utilities got to select exactly where distributed generation was installed, it might be possible to leverage DERs to provide more reliable transmission and distribution benefits. But this is not how distributed generation installations work.

For this reason, there is no basis to claim that solar PV systems always and automatically reduce losses. Furthermore, additional costs can also be the result of efforts to incorporate new distributed energy resources (DERs). On distribution systems, this point is being debated among experts, and it appears to be that DERs could well, in some circumstances, increase losses or cause additional costs to be incurred to cope with the newly bi-directional energy flow on the distribution grid, which was designed and built to accommodate one directional flows. With regard to transmission losses, it is certainly true that distributed solar PV does not rely on high voltage transmission. However, rooftop solar can also adversely impact the transmission system because of its intermittent and unpredictable nature, which requires utilities to incur expenses to assure that backup power is available in order to be able to instantaneously call upon other

[77] For a technical discussion, see M. Rivier, "Electricity Transmission," in Perez-Arriaga, ed. *Regulation of the Power Sector* (p. 276, footnote 8), which acknowledges that in some cases, **increased** demand at a node (a distribution node) can **decrease** system costs overall.

resources. Similarly, even when solar units are producing energy, that production has the potential to cause changes in the flows on the high voltage transmission in ways that add congestion to the system. Should either such circumstance occur, it is likely that losses would be increased, not decreased.

Ancillary services, similarly, can be impacted in both positive and negative ways by distributed solar generation. Certainly, there is the potential for distributed solar installations to include “smart inverters,” which have the potential to provide frequency regulation and reactive power even when the sun is not shining—but these are merely *potential* capabilities, which RNM does nothing to incentivize, and which should be thought of as a separate product from rooftop solar. To realize the potential benefit here, some form of separate compensation would be needed—and, in my opinion, such compensation should, like compensation for other forms of ancillary services, be provided as a result of services actually provided, not in the hope of services that could potentially be provided at some future date.

Environmental benefits (emission mitigation costs)

Although I recognize the Commission is not currently considering impacts external to the cost of service provision, it may be worth mentioning that even the emissions mitigation benefits associated with rooftop solar are not unquestionable. As discussed above, rooftop solar may have no emissions when producing energy[78]—but this is only a benefit if it is displacing fossil fuel generation of electricity, not competing non-carbon resources such as utility-scale solar. It is

[78] If one considers the entire cycle of manufacturing solar panels, most of which are made in the world’s most carbon intense economy, China, plus the necessity of shipping the panels halfway around the world, it can hardly be argued that solar PV is carbon neutral.

simply impossible to show that rooftop solar always displaces carbon emitting units. The issue is made even more complex by the fact that even when it is carbon emitting plants that are being displaced, the displaced plants are forced to ramp up and down in response to the intermittent flow of the solar produced energy because of the "duck curve," as discussed above. Such ramping, in most fossil plants, run contrary to the design parameters of the plant, therefore causing it to operate on a considerably less efficient basis, a circumstance which is very likely lead to more emissions, not less. Simply stated, there is no basis to assume, as a linear proposition, that more rooftop solar means fewer emissions.

Avoided purchased power/risk ("hedging")

Many "value of solar" advocates suggest that distributed solar power should get credit, when evaluating net energy metering, as a hedge against increasing natural gas costs. This does not make sense. Solar power potentially has value as a hedge against natural gas, but only for the <u>owner</u> of the solar panels. For a utility that will be buying power from solar panel owners (as is the case under RNM) the hedge value under net metering is essentially nonexistent or negative. The reason is that the price to be paid by the utility for power from rooftop solar will include all of the elements included in the monthly electric utility bill, including the full cost of energy. When gas is expensive, this price paid by non-solar customers will be higher; when it is cheaper, it will be lower. So, if it is worth hedging against variations in the price of natural gas, the utility should buy the same hedge against variations in the price of rooftop solar power. From the utility's and the non-solar customer's point of view, the two costs will vary together. Thus, the hedge value is not only zero, any consideration paid for such a hedge would be more expensive than incurring the risk from which protection is sought—this is like paying for vacation insurance that costs more than the trip itself.

“Market price mitigation” value

Another supposed value attributed to rooftop solar in many VOS studies is that by reducing demand, rooftop solar will suppress the market price for energy. This argument is seriously flawed in more than one way.

In the first place, under retail net metering, the price of rooftop solar is not market-based, or even cost-based. In fact, where there is retail net metering, the rooftop solar price is unreasonably and arbitrarily linked to the full retail price of delivered electricity, as opposed to the level of energy prices, where it should be. While, arguably, the availability of highly-subsidized rooftop solar could have the effect of reducing demand for wholesale energy, there would be no price benefit for consumers since rooftop solar, priced at full retail levels, or at the levels dictated by the inflated claims of many VOS papers, would consume all of the savings and leave little or no benefit for customers.

Setting aside the high price customers are being asked to pay for these “savings,” the second problem to flag here has to do with the different market effects of a low-priced competitive resource and a low-priced subsidized resource. Assuming that rooftop solar did have the effect of suppressing wholesale energy prices claimed by VOS advocates, it constitutes a very serious problem. If a competitively priced, unsubsidized, source of energy caused prices to decline, that would be a good thing, a natural result of market forces, but that is not at all what VOS studies are suggesting will happen with rooftop solar. Rooftop solar is subsidized by tax credits, REC/SREC markets, and by the cross-subsidy inherent in net metering and volumetric rate design. It is hard to find any economic logic to support the notion that markets are well served by using heavily subsidized products, such as rooftop solar, to drive down prices in the competitive marketplace. In short, they are suggesting that rooftop solar be heavily subsidized in order to artificially drive down prices, a result that would have highly adverse long-term consequences for the power sector and the economy as a whole.

To the extent that highly subsidized products compete with unsubsidized products in the marketplace, this distorts the market, rather than strengthens it, making it hard for otherwise competitive energy generators to stay in business. In the long run, this distortion exacerbates the capacity issues that many markets struggle to correct through capacity payments. Thus, if one assumes that rooftop solar somehow suppresses prices in the energy market, this would be highly unfortunate—it could do very serious damage to the power sector. The claimed price suppression "value" is not a value at all.

Avoided distribution grid costs

While it is theoretically possible that there could be benefits for the low voltage grid as a result of distributed solar generation, it is also possible that there will be more cost than benefits. Distributed generation imposes both costs and burdens on the grid by adding transaction costs and, in many cases, by compelling substantial changes in local networks to reflect the fact that the flow of energy is being changed from one directional to bidirectional. Significant geographic concentration of solar PV may cause the utility to have to make very substantial capital investments to upgrade the grid to accommodate the new flows put on the system. In California, in fact, serious consideration is being given to totally restructuring distribution grids in order to effectively manage the new flows, both physical and financial.[79] While such accommodations

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[79] Southern California Edison recently put forward a rate case which included $2.3 billion

can be made, policy makers do need to understand that there are costs associated with making them and should be mindful of who must bear responsibility for those costs.

Part of the problem is that, unlike other energy resources, whose siting is part of a carefully planned integrated process, in which the connecting infrastructure is often dealt with concurrently, or is capable of anticipation, distributed generation is completely outside of the utility's planning process. In fact, since the installation of rooftop solar is the result of an individual's decision, there is no possibility for the utility to plan. The result is that the operator of the distribution grid has to constantly play "catch up," a process which can be time consuming, costly, and lead to operational problems in the interim. Moreover, even in cases where a rooftop facility does reduce distribution costs, that is a specific function of location and time, something which may not be true of a neighbor's facility, much less one located across town. Thus, any generic claim that the installation of rooftop solar adds value to the grid simply is not credible.

Avoided water use

The cost of water is included in the cost of producing energy—so there should not be a need to count "avoided water use" as a separate value. In other words, if rooftop solar offsets the need for energy produced where water is used in the production process, that water is being saved and is, therefore, internalized into the cost of energy. Considering water in value calculations essentially double counts avoided water use.

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for changes to the grid to accommodate distributed energy resources. See September 21, 2016 Utility Dive article: http://www.utilitydive.com/news/how-southern-california-edisons-new-rate-case-would-transform-the-grid/426493/

A three-part rate will enable, not deter, the development of solar as an energy resource over the long term

If the assertion that distributed solar provides more than its share of value to the grid cannot be convincingly supported, what does that mean for designing a rate for distributed generation customers? As I discussed above, the flaws of a longstanding imperfect residential tariff become acute when this tariff is applied to distributed solar, creating distortions that must be addressed.

The fact is that, as Westar recognizes, solar customers are partial requirements customers, whereas non-solar customers are full requirements customer. Indeed, solar customers are a unique type of partial requirements customer.[80] It is not simply that they procure part of their power supply from suppliers other than the utility. If that were the case, the relationship would be defined by a contract that laid out the obligations of each party in discrete and clear terms. Rather, they are partial requirements customers for some of their energy supply, but rely entirely upon the utility for infrastructure and delivery services, for meeting all of their capacity requirements, and for backing up their energy supply when their solar units are not producing energy. Moreover, unlike non-solar customers, including those who practice energy efficiency, whose load is relatively predictable, the load of solar customers is not predictable, because their rooftop production of energy is not predictable. Solar customers, for the reasons noted, also impose extra burdens on the grid related to their interconnections and the effects thereof. Under

[80] Full requirements customers take all the elements of service on a 24/7 basis from the utility. Partial requirements customers take only some of those—for example, rooftop solar customers, while they do take all their demand and fixed cost services from the utility, take only some of their energy services from the utility. The same would be true for an interruptible industrial customer.

traditional tariffs, solar customers, as noted above, only paid for some of the service provided to them by the utility, unlike the non-solar customers who paid their fair share of costs. Additionally, customers who are sophisticated and affluent enough to invest perhaps as much as $40,000 for solar panels are well suited to respond to meaningful price signals that would improve the performance of their panels and reduce the capacity demands they impose on the system. In short, there are multiple economic and load profile differences that more than amply justify treating solar customers as a class quite distinct from non-solar customers, and, therefore, subject to different tariffs and conditions of service.

A three part rate creates market opportunities for "green" power, properly understood

Recent analysis by the Rocky Mountain Institute suggests the possibility that a three part rate may be very successful in reconciling the interests of solar customers with a set of incentives that drive the efficiency and development of solar technology and that establish a fair and level playing field for solar and other technologies, while eliminating cross-subsidies from non-solar to solar customers. In a recent case study of a proposed three-part rate for customers in the Arizona utility Salt River Project (SRP), by the Rocky Mountain Institute, found that rooftop solar customers who respond to the new rate through "demand flexibility" could continue to save money with rooftop PV systems, keeping them "in the money:"

> *With demand flexibility we found that solar customers on this new rate [the SRP rate] can reduce their demand charges by more than 60 percent and save more than 40 percent on their total bill, net of the spend on low-cost control technology, bringing a PV system into the money…[B]y using three simple technologies to control three major loads during peak periods, the customer can reduce their peak demand without any real sacrifice in comfort or convenience. The technologies needed to do this are simple,*

inexpensive, and available today.[81]

That is, the new rate incentivizes the use of technology to increase the cost-effectiveness of rooftop solar—exactly what RNM does not do. The really good news here is that, under the new rate, such savings to rooftop solar customers also should reflect real savings to the utility, and hence to other non-solar customers as well. This is a "win-win," no longer a cross-subsidy.

Far from being anti-competitive, a rate tailored to distributed generation customers creates opportunities, not only for rooftop solar, but for efficiency enhancing technologies, and levels the playing field for other valuable resources to compete more fairly.

Conclusions

Standard two part rates designed for full requirements customers are fatally flawed as a rate design for solar customers. Such rates fail to treat solar customers differently although they are substantially different from non-solar customers in ways which make the traditional residential rate especially unfair when applied to solar customers;

A three part rate, including a demand charge, tailored to distributed generation customers, can recognize and reward solar's energy value while creating a transparent incentive to reward any capacity value solar brings to the system by breaking out demand charges and making them visible to customers;

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[81] Quotation from blog post, "How Demand Flexibility Can Help Rooftop Solar Beat Demand Charges in Arizona." *RMI Blog* September 14, 2015 (blog available online at: **http://blog.rmi.org/blog_2015_09_14_how_demand_flexibility_can_help_rooftop_solar_beat__demand_charges_in_arizona**. The analysis referred to in the blog is discussed in detail in Dyson, Mark, James Mandel, et al. *The Economics of Demand Flexibility: How "Flexiwatts" create quantifiable value for customers and the grid.* Rocky Mountain Institute, August 2015. <<http://www.rmi.org/electricity_demand_flexibility>>

- Such a rate would benefit competition, by creating a level playing field for competing technologies to reduce customer costs and the environmental impacts of energy use;
- Such a rate would be fully consistent with commonly accepted principles of regulation and electricity pricing;
- Such a rate would ease entry barriers for green demand management and electricity storage technologies and increase the competition to help customers reduce their electric bills and environmental footprint, thereby increasing competition for that space.
- This rate would also restore the proper equilibrium in competition among various renewable resources;
- Finally, tailored rates for distributed generation customers could reduce, if not eliminate, socially regressive cross-subsidies embedded in retail net metering.

BEFORE THE STATE CORPORATION COMMISSION
OF THE STATE OF KANSAS

In the Matter of the General Investigation to Examine Issues Surrounding Rate Design for Distributed Generation Customers.	)))	Docket No. 16-GIME-403-GIE

AFFIDAVIT OF ASHLEY C. BROWN

STATE OF Massachusetts)
) ss.
COUNTY OF Middlesex)

Ashley C. Brown, being first duly sworn on his oath, states:

1. My name is Ashley C. Brown. I am Executive Director of the Harvard Electricity Policy Group at the Harvard Kennedy School at Harvard University, in Cambridge, Massachusetts.

2. Attached hereto and made a part hereof for all purposes is my Affidavit on behalf of Westar Energy, Inc. having been prepared in written form for introduction into evidence in the above-captioned docket.

3. I have knowledge of the matters set forth therein. I hereby swear and affirm that the information contained in my Affidavit is true and accurate to the best of my knowledge, information and belief.

[signature]
Ashley C. Brown

Subscribed and sworn before me this 22 day of February, 2017.

Susan Marcussian
Notary Public

My Commission expires: May 11, 2018

SUSAN MARCUSSIAN
Notary Public, Commonwealth of Massachusetts
My Commission Expires May 11, 2018

Affidavit of Jeff Martin
Docket No. 16-GIME-403-GIE

I. Introduction

My name is Jeff Martin and I am the Vice-President, Regulatory Affairs for Westar Energy, Inc. (Westar). I have a Bachelor of Science degree in Electronic Engineering Technology from Pittsburg State University and a Master of Business Administration degree from Kansas State University. I have been with Westar for more than twenty-three years and have had various positions in Field Operations, Information Technology, and Regulatory Affairs. As the VP, Regulatory Affairs, I am responsible for leading Westar's Regulatory Affairs team in all aspects of our regulatory state and federal activities at the Kansas Corporation Commission, the Federal Energy Regulatory Commission and the North American Electric Reliability Corporation.

A. <u>Rate filing</u>

On March 2, 2015, in Docket 15-WSEE-115-RTS (the "15-115 Docket"), Westar Energy, Inc. (Westar) filed a rate case Application with the Commission. Among other requests, Westar proposed two new optional residential rate tariffs – the Residential Demand Plan and Residential Stability Plan. As part of the proposal, new residential customers with private distributed generation (DG) would have the option to receive electric service under one of the two new residential rate tariffs. In addition, Westar proposed several new renewable energy program offerings to assist customers, including community solar and a solar block subscription.

Westar's proposals were met with opposition from several parties including many solar providers who opposed the tariffs in their entirety and Staff who argued for deferral of the issues to a separate docket.

B. Settlement resulting in new rate schedule and generic docket

The parties to the 15-115 Docket reached a settlement regarding rate design for private DG customers and, as a result, Westar implemented a new rate schedule for new private DG customers. As a starting point, the new rate schedule was designed to be identical to the existing residential rate schedule (as adjusted by the Commission's order in the 15-115 Docket). It was implemented for the purpose of recognizing these customers as different from traditional (non-DG) residential customers and identifying which private DG customers would be grandfathered; that is, those DG customers who installed and connected their private DG systems to Westar's infrastructure prior to October 28, 2015, would continue under the "Residential Standard Service" tariff. Customers who installed and connected their private DG systems on or after October 28, 2015, would be served with the new "Residential Standard DG" tariff. Under the settlement, the parties agreed that all other substantive issues related to rate design for DG customers would be resolved in a generic proceeding to be opened by the Commission.

II. A separate and differentiated rate schedule is needed for private DG customers

A. DG partial requirements customers use the electrical system differently than full-requirements customers

As will be discussed in depth by Westar witnesses Dr. Ahmad Faruqui and Ashley Brown, private DG customers have different needs and place different demands and costs on the electric system than non-DG, full-requirements customers. Unlike the majority of our customers – who receive all of their electrical requirements from the serving utility – private DG customers are partial requirements customers – intermittently generating some or all (and potentially, more than) of their energy needs while relying on the serving utility for some or all of their requirements when their systems are not producing sufficiently (e.g., cloudy days) or when they desire to use the electric system to sell private DG production in excess of their energy needs. Because private DG customers can rely on solar generation for only a portion of their energy needs, private DG customers must depend on the serving utility at night, on cloudy days, or when their energy demands cannot be met through self-generation. Also, because their generation is not "dispatchable" and because the serving utility has a legal obligation to serve, the utility must have sufficient generation available to meet private DG customers' requirements regardless of whether they are producing electricity.

B. <u>The combination of net metering and the failure to have a separate and differentiated rate schedule results in a cross subsidy</u>

Residential rates are designed for most of our customers with just two-part rates: a fixed customer charge and a variable energy charge.[1] A customer's monthly bill consists of a set charge independent of usage plus an energy charge on a per kWh basis for energy used. However, a large portion of Westar's costs – like those of all electric energy companies – are either fixed or sunk costs associated with the infrastructure. In other words, such costs – including the investment in generation, transmission, distribution and customer service assets – are already included in the cost to serve our customers. The cost of the infrastructure is not reduced when private DG customers substitute their own electricity generation for that of the serving utility. However, because of the use of two-part rates, the vast majority of the utility's fixed costs already incurred to serve residential customers are only recovered through the variable energy charge. The two-part rate has historically worked for recovery of fixed costs through energy charges because private generation was not feasible in the past and customers relied on the energy company to generate

[1] Westar's residential rates also include a number of surcharges or riders. Each of those are charged on an energy, *i.e.*, per kWh, basis.

and deliver all the energy they needed, resulting in a fairly stable platform for recovery of incurred costs.

When private DG customers generate electric energy with their private resources, they reduce their consumption of energy generated by the serving utility. Private DG customers also avoid paying for a portion of the fixed and already incurred costs associated with generation, transmission, distribution and customer service, even though they continue to rely on some or all the components of those systems. That isn't fair. In a subsequent rate case, the reduction in sales to private DG customers results in a per kWh increase in rates to non-private DG residential customers. As a result, non-private DG customers pay more than they otherwise would absent the DG customer and thereby provide a subsidy to DG customers. As discussed by Westar witnesses Brown and Dr. Faruqui, the subsidy is particularly troubling because it statistically is funded disproportionately by customers with lower incomes than most private DG customers, and with the lower incomes they have fewer options to install their own private DG. *See* Faruqui Affidavit, at pp. 8-9; Brown Affidavit, at pp. 28-29.

A three-part rate for private DG customers will modernize the current rate design to better match fixed costs to fixed charges and variable costs to variable charges, thereby reducing or eliminating the cross subsidy. Perfectly structured, the three-part rate would continue to include a variable energy charge (equal to the variable costs of generation) and components that would fully recover the fixed costs associated with operating the electric system. Under such a properly structured rate, customers who self-generate will generally avoid only those costs that are also avoided by the serving utility and therefore non-DG customers will not be disadvantaged by the presence of private DG customers on the system. Because private DG customers taking service under Westar's Residential Standard DG tariff will be impacted by any change to the rate paid by customers under that tariff,[2] the longer it takes to modernize the rate structure, the higher the number of customers who will be impacted. The number of private DG customers on Westar's system is increasing – it has roughly doubled since the time of the 15-115 Docket (2015 rate case) to 550 currently.

III. Claimed Benefits do not Justify the Subsidy to Private DG Customers at the Expense of non-DG Customers

Advocates of the status quo in rate design fail to address the concerns and inequity discussed above, alleging that either intangible or unquantifiable benefits of private DG justify unfair rates for those who cannot afford to install their own private DG systems. Westar disagrees that any of these alleged benefits justifies maintaining the status quo rate design for private DG customers. First, Westar believes the longstanding principles of cost allocation and rate design should prevail; that is, rates should be set based on the quantifiable cost to serve. Accordingly, rates should be redesigned to eliminate the unfair subsidy and uphold these long-held principles. The unquantifiable benefits claimed by private DG advocates are external to the utility's cost of service structure and are not proper to consider in the rate making process.[3]

Second, the benefits do not justify an unfair subsidy because they are intangible, unquantifiable, and to the extent they do exist, those same benefits are equally available through universal-scale renewable generation provided by an energy company (i.e., utility scale solar), particularly when universal-scale renewables are more affordable and accessible for all customers

[2] Under the settlement agreement approved by the Commission in the 15-115 Docket, DG customers that had installed and connected their DG systems to Westar's system prior to October 28, 2015, are grandfathered under the "Residential Standard Service" tariff; however, DG customers who install and connect their DG systems on or after October 28, 2015, take service under the "Residential Standard DG" tariff and will be impacted by any tariff change that is implemented as a result of this docket.

[3] The Commission stated in its Order Opening General Investigation in this docket that it will only consider "the quantifiable costs and quantifiable benefits of DG" when determining the appropriate rate structure for DG customers. Order Opening General Investigation, Docket No. 16-GIME-403-GIE, at ¶ 10 (July 12, 2016).

unlike that of private DG. Additionally, as Dr. Faruqui and Mr. Brown discuss in their affidavits, in some cases, private DG resources can actually increase the utility's cost of service.

I discuss briefly each of the possible benefits identified by Staff in its motion to open this general investigation docket (see pages 5-6 of Staff's Report and Recommendation in support of Motion to Open Docket) and explain why none of these alleged benefits support a continuation of the existing rate structure and the subsequent unfair cross subsidy for private DG customers. Westar witness Brown also discusses the nature of many of these alleged benefits in his affidavit at pages 43-56.

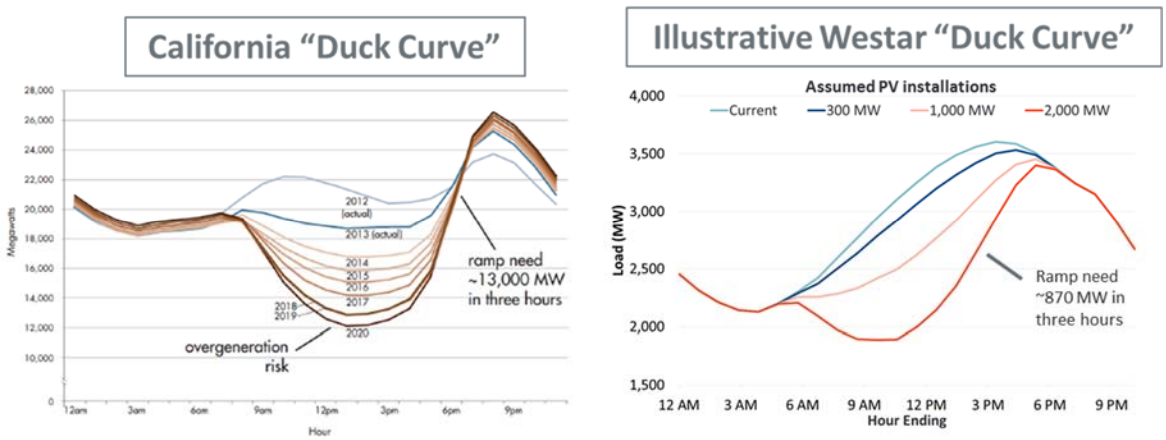
A. Avoided energy costs

Westar recognizes that private DG generation allows the serving utility to avoid energy costs. However, under the current structure (net metering combined with the existing two-part rate structure), private DG customers are overcompensated for the avoided energy costs that result from the DG resource's energy production. Under the existing structure, when private DG operates, they receive a credit equal to the marginal retail rate, which is the price customers pay (or save) for their last unit of energy used (or saved). Such a credit overstates the costs avoided by the utility (which are really only equal to the variable cost of generation), and comes at the expense of non-DG customers; not of the utility or its shareholders. A three-part rate properly recognizes the avoided energy costs that result from private DG production.

B. Avoided Generation Capacity Costs

As Westar witness Dr. Faruqui's affidavit shows, the addition of DG has little impact on generation capacity. That is because private DG systems are generally constructed to maximize energy production rather than to curb demand on the system or for peak shaving. The nature of private solar DG production means it drops off just as residential consumption increases as residents return home from work, turn on air conditioners, lights, and appliances as dinner time approaches. The resulting "duck curve," so named based on its shape, shows that the utility must ramp up other generators rapidly to meet these needs. *See* Figure 5 from page 10 of Dr. Faruqui's affidavit, reproduced below.[4]

Figure 5: The California and Westar "Duck Curves"



The shape of this curve demonstrates that the capacity required to meet peak demand is only modestly reduced by the introduction of private solar DG to the generation mix and utilities are required to have additional ramping capability from other resources in order to compensate for the drop-off in solar production at peak.

C. <u>Avoided Ancillary Service and Capacity Reserve Costs</u>

Because private DG does not reduce peak demand significantly, it has little impact on the energy company's capacity costs, and any such capacity may have little, if any value, if adequate

[4] Dr. Faruqui notes that "[t]he chart illustrates the change in system load shape that would occur at various levels of PV installation. It is not intended to be a forecast of PV adoption in Westar's service territory." Faruqui Affidavit, at p. 10.

capacity already exists. Additionally, because it is unpredictable and therefore not dispatchable, private DG may actually increase ancillary service costs.

D. Avoided transmission costs

Transmission is engineered and constructed to meet peak needs. Because private DG does not significantly reduce peak demand and because the serving energy company is required by law to provide backup to private DG customers when their private DG output is decreased or unavailable, private DG does not reduce transmission costs.

E. Avoided distribution costs

Distribution facilities are also engineered and constructed to meet peak needs. Consequently, while it is possible that there could be benefits for the low voltage grid as a result of private DG (i.e., a reduction of loads on distribution lines which theoretically might lead to distribution investment savings years down the road), it is also possible that there will be more cost than benefits. In fact, as noted by Westar witness Brown, private DG often imposes requirements for substantial changes in local networks to reflect the fact that the flow of energy is being changed from one directional to bidirectional. If DG is geographically clustered, it could lead to new capacity constraints on the distribution system in areas where transformers are not equipped to handle large amounts of excess generation. *See* Faruqui Affidavit, at p. 3.

F. Avoided environmental costs

Private DG can help avoid environmental impact, however, it is not unique in its ability to have this positive effect. The same effect can be achieved by the installation of more efficient universal scale renewable generation. Again, this factor does not support discrimination in favor of private DG over universal scale renewable generation through the subsidies inherent in the current rate structure and net metering. It is also possible that the increased ramping up and down of fossil fuel units required as a result of private DG resources actually leads to more emissions because it results in the fossil fuel plants running contrary to the design parameters of the plant and on a less efficient basis. *See* Brown Affidavit, at p. 52.

G. Avoided renewables costs

The argument that private DG somehow allows an energy company to avoid the cost of renewables is based on the notion that private DG is "free" energy for an energy company with respect to the requirements under a renewable portfolio standard (RPS). For Kansas specifically, private DG does not avoid costs because Kansas' RPS is strictly voluntary; there are no penalties for not meeting the goal. Given that economies of scale are important in renewable generation, energy companies can produce renewable energy on a universal scale at a fraction of the cost of private residential solar. All customers should be allowed to purchase the most cost effective renewable energy available, not just those who can afford private solar and/or those that have owned and adequate rooftop space.

H. Price mitigation benefits

Private DG does not insulate an energy company from the price volatility of different fuel sources because, while somewhat predictable, it is not dispatchable. Other dispatchable generation is still required to balance load.

I. Economic development

Building additional utility infrastructure is economic development. Westar has been a major contributor to Kansas economic development for more than 100 years through its construction of conventional power plants, substations, transmission and distribution systems, energy efficiency programs, or universal scale renewable energy. These projects created hundreds of construction and permanent jobs. These are important jobs created also with the understanding that the underlying projects themselves were at the lowest reasonable cost to serve customers. We must guard against projects whose primary driver is job creation at the sacrifice of low-cost cleaner energy. Additionally, the economic development argument does not consider the jobs lost in other sectors of the power industry because of the changing generation mix. Jobs in the private DG industry come at the expense of jobs elsewhere in the industry, they are not a net addition to the economy.

J. Health benefits

The reduction of emissions through the introduction of private DG can provide health benefits, but again, this is the result of it being emission-free and renewable, not distributed. Accordingly, any such benefits are equally applicable to universal scale emission-free sources as they are to private DG. As with other positive impacts of renewables, this factor does not support discrimination in favor of private DG over universal scale renewable generation through the unfair cross subsidies inherent in the current rate structure and net metering.

K. Grid Security

Electric utilities are heavily regulated by state and federal commissions to be compliant with cyber and reliability standards. The North American Electric Reliability Corporation (NERC) has numerous standards to ensure that the security and the reliability of the electric power system is achieved. Private DG does not fall under these same standards and level of scrutiny and would not likely increase grid security in any manner.

IV. Conclusion

Today, we have an unfair practice with residential private DG customers receiving a subsidy from non-DG customers through the use of net metering and two-part rates. The unfair subsidy is hidden from customers and not the result of a robust public policy debate. The subsidy is particularly inappropriate because it tends to be paid disproportionately by customers who cannot afford to install private DG of their own, compensating customers with higher income customers who can afford private installations. The solution to help mitigate this problem is to make rates fair and equitable, modernizing the private DG rate structure to establish a three-part rate for private DG customers so that the energy charge recovers (and credits) only the costs truly incurred (avoided) by private energy production. The result of such a rate design will be to remove the current cross subsidy and remove uneconomic incentives that will provide a balanced platform to encourage additional distributed generation in Kansas.

**BEFORE THE STATE CORPORATION COMMISSION
OF THE STATE OF KANSAS**

In the Matter of the General Investigation to Examine Issues Surrounding Rate Design for Distributed Generation Customers.	)))	Docket No. 16-GIME-403-GIE

AFFIDAVIT OF JEFF MARTIN

STATE OF KANSAS)
) ss.
COUNTY OF SHAWNEE)

Jeff Martin, being first duly sworn on his oath, states:

1. My name is Jeff Martin. I am the Vice-President, Regulatory Affairs for Westar Energy, Inc.

2. Attached hereto and made a part hereof for all purposes is my Affidavit on behalf of Westar Energy, Inc. having been prepared in written form for introduction into evidence in the above-captioned docket.

3. I have knowledge of the matters set forth therein. I hereby swear and affirm that the information contained in my Affidavit is true and accurate to the best of my knowledge, information and belief.

Jeff Martin

Subscribed and sworn before me this 9th day of March, 2017.

Donna G. Quinn
Notary Public

My Commission expires: 8/28/2020

Donna G. Quinn
NOTARY PUBLIC~STATE OF KANSAS
MY APPT EXP: 8/28/2020

Valuation of Distributed Solar: A Qualitative View

A critical evaluation of the arguments used by solar DG advocates shows that those arguments may often overvalue solar DG. It is time to reassess the value of solar DG from production to dispatch and to calibrate our pricing policies to make certain that our efforts are equitable and carrying us in the right direction.

Ashley Brown and Jillian Bunyan

Ashley Brown *is Executive Director of the Harvard Electricity Policy Group and Of Counsel in the Boston office of the law firm Greenberg Traurig LLP. Mr. Brown is a former Commissioner of the Public Utilities Commission of Ohio and former Chair of the National Association of Regulatory Commissioners Electricity Committee.*

Jillian Bunyan *is an associate in the Philadelphia office of Greenberg Traurig LLP. Prior to joining the firm, Ms. Bunyan was an attorney in the United States Environmental Protection Agency's Office of Regional Counsel in Seattle, Washington.*

I. Assessing the Value of Distributed Solar Generation – An Overview

The purpose of this article is to assess the value of residential distributed generation (DG) solar photovoltaics (PV) and appropriate pricing for its value and output. In particular, the article will address the question of whether retail net metering, the way that it is presently applied in most states, is an equitable way to compensate customers who own or lease solar DG. The article will also critically examine the argument for the ''value of solar'' approach to compensating residential solar DG customers. The article will conclude that retail net metering and ''value of solar'' are severely flawed schemes for pricing solar DG.

Retail net metering overvalues both the energy and capacity of solar DG, imposes cross-subsidies on non-solar residential customers, and is socially regressive because it effectively transfers wealth from less affluent to more affluent consumers. The ''value of solar'' approach being advanced by

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some solar DG advocates subjectively, and often artificially, inflates the value of solar DG and discounts the costs. This article also concludes that proposals for market-based energy prices, as well as demand and fixed charges as applied to solar DG hosts, are reasonable ways to rectify the cross-subsidies in net metering. It suggests that market-based prices for solar DG provide the best incentives for making solar more efficient and economically viable for the long term.

Solar PV has some very real benefits and long-term potential. The marginal costs of producing this energy are zero. If one looks at environmental externalities, then the carbon emissions from the actual process of producing this energy itself, without taking the secondary effects into consideration, are also zero. Significantly, the costs of producing and installing solar PV have declined in recent years, adding to the potential long-term attractiveness of solar. Those are very real benefits that would be valuable to capture. In its current, most common configuration, however, solar DG has some drawbacks that inhibit it from capturing its full value.

Solar PV is intermittent and thus requires backup from other generators and cannot be relied on to be available when called upon to produce energy. Thus, its energy value is entirely dependent on when it is produced and its capacity value is, at best, marginal. To fully develop the resource, therefore, it is imperative to provide pricing that will incent the fulfillment of solar PV's potential, by linking itself to storage, more efficient ways of catching the sun's energy, or with other types of generation (e.g. wind) that complement its availability. Thus, it is critical that prices be set in such a fashion as to provide incentives for productivity and reliability and not to subsidize solar DG at a decidedly low degree of optimization. Currently, rates for most residential consumers are based on volume. That is, residential customers are simply billed based on the number of kilowatt-hours that they consume based on average costs to serve all residential consumers. Solar has huge potential, but to attain it, solar DG needs to receive the price signals to actually fulfill its potential.

In its current, most common configuration, solar DG has some drawbacks that inhibit it from capturing its full value.

Not only does net metering deprive solar PV of the price signals necessary to capture its full value, it also leads the changes in retail pricing that undermine the promotion of energy efficiency. As solar DG becomes more widely deployed, utilities and their regulators will likely become increasingly concerned with diminution of revenues required to support the distribution system that is caused by the use of net metering. That concern will inevitably lead utilities and regulators to recover more of their costs through the fixed, rather than the variable, components of their rates. Thus, the price signal to be more efficient will be substantially diluted.

Many in the solar industry have come to recognize that retail net metering (NEM) is, in this age of smart grid and smart pricing, no longer a defensible method for pricing solar DG. Having recognized the inevitable demise of a pricing system that favors solar DG through cross-subsidization by other customers, many solar DG advocates have shifted to an argument that pricing should be based on consideration of the ''value of solar.'' While the authors do not subscribe to that point of view, as the argument is being included in the national conversation, it seems appropriate to address it.

II. Solar DG and Retail Net Metering – Definition of Terms

Powering your home with clean energy generated from the

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solar panels on your roof, and selling the excess energy to the utility, are appealing prospects to a public increasingly attuned to environmental, energy efficiency, and self-sufficiency considerations. It is not hard to see why solar DG has substantial public appeal.

To begin, it is necessary to note that the terms ''net metering,'' ''retail net metering,'' and ''net energy metering'' will be used interchangeably and synonymously throughout the article. Net metering refers to when electricity meters run forward when solar DG customers are purchasing energy from the grid. When those customers produce energy and consume it on their premises, the meter slows down and then simply stops, and when the customer produces more energy than is consumed on the premises, the meter runs backwards. Thus, the solar DG customer pays full retail value for all energy taken off the grid, pays nothing for energy or distribution when self-consuming energy produced on the premises, and is paid the fully delivered retail price for all energy exported into the system. At the end of whatever period is specified, the meter is read and the customer either pays the net balance due, or the utility pays the customer for excess energy delivered. The reconciliation is made without regard to when energy is produced or consumed. This is how transactions between owners of residential DG and utilities have traditionally been handled.

There are other forms of net metering such as wholesale net metering, where exports into the system are compensated at the wholesale price, often the local marginal price (LMP). There are other variations as well, but for purposes of the article, when the terms NEM or net metering are used, they refer to the retail variety.

There are, conceptually, four possible approaches to pricing energy produced by solar DG.

There are, conceptually, four possible approaches to pricing energy produced by solar DG. One market-based approach is to set the price to reflect the market clearing price in the wholesale market at the time the energy is produced. A second approach would be a cost-based approach, where the price is set based on a review of the costs or according to standard costing methodology. A third approach, already defined above, would be net metering. Finally, a fourth approach would be to administratively derive a ''value of solar'' based on analysis of avoided costs and whatever else the evaluators believe to be worthy of measure.

As you will see, while the authors do not believe this fourth approach to be appropriate, analysis of the criteria its advocates believe are important should be conducted and evaluated – not to set the price, but simply to establish the context for evaluating the reasonableness of the pricing methodology approved.

III. 'Value of Solar' vs. Wholistic Analysis

Optimally, prices for electricity are determined by a competitive market or, absent competitive conditions, should be derived from cost-based regulation. In both cases the prices are subjected to an external discipline that should result in efficient resource decisions devoid of arbitrary or ''official'' biases. Subjective consideration of the ''value'' of particular technologies and where they may rank in the merit order of ''social desirability,'' effectively removes the discipline that is more likely to produce efficient results. Moreover, even where non-economic externalities are thrown into the valuation mix, the pricing of an energy resource must still be disciplined by examination of the economic merit order in attaining the externality objective. Whereas both the marketplace and transparent cost-based regulation are likely to produce coherent pricing that

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allows us to enjoy a degree of comfort knowing that efficient performance will likely lead to productivity, subjective consideration of soft criteria, like ''value of solar,'' are a step away from economic coherence and efficiency.

Economics are critical and efficiency is of vital importance. There are also other economic values, besides efficiency, including those that go beyond short-term efficiency. Certainly, many people believe that other, non-economic factors need to be considered. Similarly, the fairness of the impact on customers also needs to be factored into any decision. There has, for many years, been a running debate in electricity regulation as to whether externalities ought to be factored into regulatory decisions. This article does not intend to join that debate, nor express any point of view as to what is permissible or impermissible under applicable law. Rather, this article suggests that if externalities are to be considered, then all relevant ones deserve attention, as opposed to ''cherry picking'' the issues to best protect a particular interest. Further, if non-economic objectives are to be factored into ratemaking, then it is wise to carefully consider the most economically efficient ways of attaining those objectives.

There are a number of criteria that are important to the full valuation of solar PV. One should begin by looking at the cost of producing energy. Beyond that, the criteria would include availability/capacity, reliability, energy value, impact on system operations and dispatch, transmission costs and effects, distribution costs and effects, and hedge value. Solar DG proponents often phrase these issues in terms of avoided costs. In addition to those dimensions, there are also the following: degree of subsidization and cross-subsidization, efficiency considerations, impact on alternative technologies, market price impact, reliability, and social effects including the environmental, customer, and social class impacts. There is also the issue of whether solar DG enhances the level of competition in the industry.

Certainly, many people believe that other, non-economic factors need to be considered.

IV. Net Energy Metering – Why Are We Paying More for Less?

Retail net energy metering, as practiced, does not capture all of the value enumerated above. NEM significantly overvalues distributed solar generation. More specifically, it does the following:

1. Creates a cross-subsidy from non-solar to solar customers;
2. Fails to reflect the inefficiency of small-scale solar PV relative to other forms of generation, including alternative renewable resources;
3. Constitutes price discrimination in favor of an inefficient resource;
4. Significantly overvalues both the capacity and reliability value of solar DG;
5. Adversely impacts the degree of competitiveness in the industry;
6. Artificially inflates the transmission value of solar DG;
7. Fails to account for the fact that the value of energy varies widely depending on when it is actually produced;
8. Distorts price signals for energy efficiency;
9. Causes socially regressive economic impact;
10. Assumes system benefits from solar DG that, in fact, may not exist;
11. Overvalues its contribution to carbon reduction;
12. Vastly inflates its value as a fuel hedge; and
13. Undervalues and underfunds the distribution system.

Despite failing to capture these values, NEM has become the prevalent form of tariff for residential solar DG in

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the United States. This is because NEM was never developed as part of a fully and deliberatively reasoned pricing policy. NEM was simply never a conscious policy decision. It is basically a default product of two (no longer relevant) considerations, one practical and the other technological. The practical reason is that residential distributed generation had such an insignificant presence in the market that its economic impact was marginal at best. Thus, no one was seriously concerned about ''getting the prices right.'' The second, technological reason is that until recently the meters most commonly deployed, especially at residential premises, have had very little capability other than to run forward, backward, and stop. Thus, for technical reasons, NEM was simple to implement and administer and, as a practical matter given the paucity of DG, there was no compelling reason to go to the trouble of remedying a clearly defective pricing regime. Many states have recognized the problems with NEM but, seeing no alternatives, put in place production caps to limit any harm caused by a clearly deficient pricing regime.

V. Residential Retail Net Metering Sets Up Unfair and Counterproductive Cross-Subsidies

Beyond failing to capture the values above, there are other problems with NEM. Under NEM, when DG providers export energy to the system, consumers are required to pay them full retail rates for a wholesale product. What everyone agrees upon is that solar DG provides an energy value, but there is considerable disagreement about what that value is. Solar proponents argue that solar DG has a capacity value as well. That value, if it exists at all, is minimal. While there may well be reasons to treat DG differently with respect to wholesale transmission there is, absent a solar host leaving the grid, absolutely no reason to discriminate between wholesale and DG products with regard to the fixed costs of the distribution system and its operations.

If the costs of the distribution system were variable with energy production, that exemption would be sensible, but they are not.

Under NEM, however, solar DG providers are compensated at full retail prices for what they provide. That includes the not-insignificant cost of services that they do not provide, including distribution costs, administrative, and back office operations. There can be no justification for forcing consumers to pay a provider for service that they not only do not provide but, in fact, have no capability to provide.

Solar DG producers remain connected to the grid and are fully reliant upon it during the many hours of the day when solar energy is not available. Under NEM, that solar DG producer is excused from paying his/her share of the costs of the distribution system when energy is being produced on the premises. If the costs of the distribution system were variable with energy production, that exemption would be sensible, but they are not. Distribution costs are fixed, and do not vary with energy production or consumption. Thus, excusing solar DG customers from paying for their own distribution costs when their solar units are producing energy has no justification in either policy or economics. Making matters worse, the costs solar DG providers do not pay under NEM are either reallocated to non-solar customers or have to be absorbed by the utility. Both outcomes are unacceptable and unjustifiable. There is no reason why solar DG customers should receive free backup service, compliments of either their neighbors or the utility.

Utilities are obliged to provide full requirements service to all of their customers, including, of course, their solar host

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customers. In regard to solar hosts, the utility is obliged, in case the on-premises generation does not cover their full demand, to fill the gap between the full demand and the amount of self-generation. Utilities are also obliged to purchase energy and/or capacity so that solar hosts may rely on the utility when solar units are not generating. Given that solar PV units are intermittent and unpredictable regarding when they will produce, providing that backup is an ongoing responsibility and cost to utilities. Compounding those costs is the fact, as stated elsewhere in the article, peak times of electricity use (i.e. when prices are highest) are trending later in the day, when solar PV does not produce. As such, utilities must provide electricity to solar hosts at times when demand is high and energy prices are high. It would violate a the fundamental principle of regulation that cost causers should pay for the costs they impose, not to recognize the actual costs of that backup service in the rates paid by solar hosts.

Another cross-subsidy relates to the intermittent nature of solar energy. No utility with an obligation to serve can be fully reliant on the availability of solar when it is needed. Indeed, no solar host who values reliability can afford to be dependent on his/her own solar DG unit. While this point will be discussed further *infra* suffice it to say that this gives rise to two types of demand charge related cross-subsidy. The first arises when the distributor relies on the availability of solar for making day-ahead purchases and the other arises when it does not do so. When it does rely on the availability of solar and it turns out that solar energy is not available when called upon, the

utility is compelled to purchase replacement energy in the spot market at the marginal cost, which is almost certainly higher than the price of the solar energy on whose availability it had relied. In notable contrast to what happens in the wholesale market when a supplier who is relied upon fails to deliver, those incremental costs have to be borne by the utility, which passes them on to all customers, as opposed to being borne by the specific solar DG customer whose failure to deliver caused the costs to be incurred.

If the distributor, in recognition of solar's intermittency, instead chooses to hedge against the risk of solar's unavailability, the cost of the hedge is likewise passed on to all customers rather than simply those whose supply unpredictability caused the cost to be incurred. Both of these forms of cross-subsidy violate a bedrock principle of regulation – costs should be allocated to the cost causer. The function of that principle, of course, is to provide price signals to improve performance, but NEM fails to provide such signals and essentially holds solar DG providers harmless for their own very low capacity factors and inefficient performance.

NEM cross-subsidies, in large part, provide short-term benefits to the solar DG industry, but are highly detrimental to the value of solar in the long term. In the short term they constitute a wealth transfer from non-solar customers to the solar industry. In the long term, however, they are actually harmful to solar energy because NEM provides absolutely no incentive to improve the performance of a generating resource that, among renewables, already ranks last in efficiency and in cost effectiveness for reducing carbon emissions. In effect, the solar DG industry is putting its short-term profits ahead of the long-term value of solar energy. If solar DG advocates prevail in seeking to maintain NEM, that victory will be short-lived, because markets, both regulated and unregulated, do not prop up inefficient resources over the long term.

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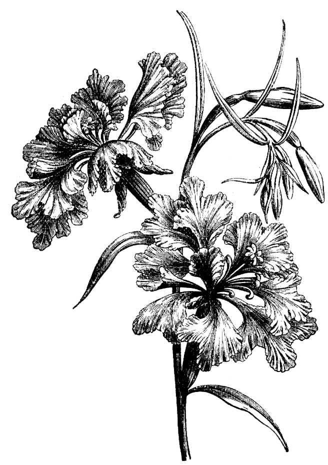
NEM is also woefully ineffective at providing the appropriate price signals. Electricity prices can be quite volatile over the course of every day and vary seasonally as well. Rather than reflecting those prices, NEM simply treats all energy the same regardless of the time during which it is produced. For example, NEM fails to differentiate between energy produced on-peak and off-peak. In one scenario, it prices off-peak solar DG at a level that is averaged with on-peak prices, thus effectively over-valuing the energy. Conversely, if solar DG were actually produced on-peak, NEM would average that price with off-peak prices, thus undervaluing the energy. Any form of dynamic pricing, ranging from time of use to real-time, could address this issue with more precision than flat, averaged prices. Interestingly, under the first scenario, cross-subsidies would be paid to solar producers, while in the second scenario, solar producers would be cross-subsidizing the other ratepayers. In short, the price signal, and the efficiency that would flow from that, is rendered incoherent.

Some may argue that cross-subsidies are necessary to promote the growth of renewable energy, and certainly that can be debated. However, modernizing NEM to provide appropriate price signals would not remove the tax credits and other government-sanctioned or -sponsored subsidies. The fact that conscious subsidies and/or cross-subsidies are designed to promote a particular technology raises two key issues. First, many would argue that the government, including regulators, should not be picking winners and losers in the marketplace. While there may be merit to that view, it must also be recognized that, there may be



circumstances where, for policy reasons, government might want to provide support for a socially and economically desirable technology and/or assist it with research funding and to get it over the commercialization hump. That leads inexorably to the second and more relevant issue concerning solar DG: namely, that subsidies and cross-subsidies need to be designed as near-term boosts rather than a permanent crutch, and should be transparent. In other words, subsidies/cross-subsidies should be designed to serve as both a stimulus for the designated technology and an incentive to the producers and vendors of the technology to become more efficient. It might also be noted that subsidies from the Treasury are more appropriate for achieving broad social benefits that are cross-subsidies derived from a subset of the full society deriving the benefit.

In the case of solar DG, the objective of a subsidy/cross-subsidy would be to attain grid parity, assuming reasonably efficient operations, with other resources. The objective is to assist a technology to achieve commercial viability. The problem with NEM, of course, is that it is effectively an arbitrary financial boost of potentially endless duration, with absolutely no built-in incentive to increase efficiency and/or to achieve grid parity. In effect it requires non-solar customers to pay more for the least efficient renewable resource in common use and provide the solar industry with no economic incentive to improve its productivity or availability or wean itself off dependence on the cross-subsidy. It also has the effect of putting more efficient resources, particularly other renewables, at a competitive disadvantage. In short, NEM effectively substitutes political judgment for economic efficiency to determining marketplace success.

The reason why solar DG vendors and providers cling to cross-subsidies is because they find more comfort in receiving substantial cross-subsidies than

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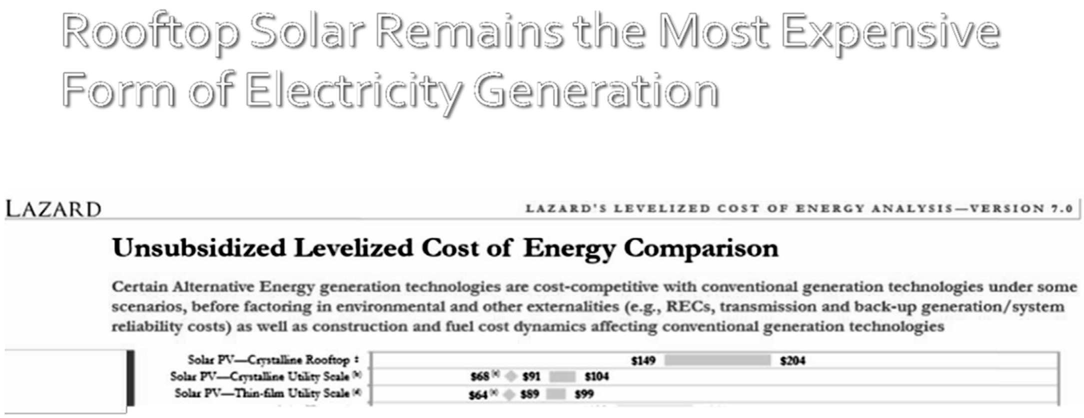

Figure 1: Rooftop Solar Remains the Most Expensive Form of Electricity Generation

they do in the prospect of becoming competitive. Solar DG is the most expensive form of renewable generation that is widely used today (Figure 1).

The technological and practical reasons for permitting such incoherent pricing are no longer present in the marketplace. We now have pricing methods that are capable of measuring DG production as well as consumption on a more dynamic basis. In addition, solar DG market penetration has dramatically increased to the point that it can no longer be dismissed as marginal, so appropriate pricing is now a non-trivial issue. In addition, we now have very precise, location-specific energy and transmission price signals that provide a very transparent market price by which one can measure the economic value of distributed generation. These new developments, plus the fact that NEM was put in place on a default basis, mean that it is now time for a full-blown policy consideration of the most appropriate pricing policy for distributed generation.

For all of the reasons noted, NEM pricing results in large cross-subsidies, offers no incentives for efficiency – indeed, may even provide disincentives to invest in efficiency improvements – and results in consumers paying energy prices for solar DG that are far in excess of its market value and not even subject to cost-based oversight. Moreover, its *raison d'être* – inability to more accurately price solar DG facilities and low market penetration by solar energy – no longer exists. Solar energy is penetrating the market in greater numbers and is likely to continue to do so. Secondly, more sophisticated pricing enables us to measure solar energy and customer behavior on a much more efficient, dynamic basis. The fundamental reality is that NEM completely fails to capture the value of the product being priced.

VI. Placing a Value of Solar DG – Pricing and Economic Efficiency

Needless to say, pricing is of critical importance. It is important to address pricing in the context of tangible, enumerated values. Such an analysis is in contrast to certain efforts by solar DG advocates to attach a subjective value to solar and then derive prices from that value. It is preferable to derive prices from the values established by either costs or market, not ephemeral and subjective considerations.

It is worth re-emphasizing just how imperfect NEM actually is. The price of electric energy is not constant. Wholesale markets reflect that reality. Net metering and many forms of incentives do not reflect the values established by the market. Rather, a net metering regime relieves the solar panel host of any obligation to pay for the costs of the distribution system when energy is being produced, even though he/she

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Table 1: Rooftop Solar Subsidies Heavily Utilize Funding from Non-Solar Customers

DTE Energy

Consumers Energy
Count on Us

SolarCurrents and Net Metering funding mechanism for residential customers

	SolarCurrents (Phase 1)	SolarCurrents (Phase 2)	Funding Mechanism
Up-front solar subsidy	\$2.40/W	\$0.20/W	Renewable Surcharge
On-going solar subsidy	\$0.11/kWh	\$0.03/kWh	Renewable Surcharge
Net metering subsidy (unrecovered fixed cost)	\$0.09/kWh	\$0.09/kWh	*Unrecovered fixed costs are funded by non-solar customers
Total SolarCurrents and Net metering subsidy	**\$0.20/kWh**	**0.12/kWh**	

remains reliant on it and, when the meter runs backwards, is effectively paid the full retail price for energy exported from the customer's premises. As a point of illustration, see Table 1 for a funding mechanism for residential customers presented by DTE Energy to the Michigan Public Service Commission. According to DTE, the 9 cent per kilowatt-hour (kWh) net metering credit represents a differential that non-participating customers must pay.

Under NEM, compensation at retail rates is not cost-reflective because net metering means that solar DG energy exported into the distribution network is compensated at the full bundled retail rate rather than at a price based on the unbundled cost of producing the energy. In almost all jurisdictions, that retail rate is flat and constant. Thus, it does not reflect the obvious fact that the energy has greater value at peak demand than it does off-peak. It is a deeply flawed value proposition. The fact is that the wholesale market produces hour-by-hour prices that provide generators, renewable and non-renewable alike, and consumers with important price signals that reflect real-time values. Both generators and demand responders are compensated according to those real-time prices. Solar DG-produced energy, by contrast, is compensated on a basis that lacks a foundation in either market or cost. The compensation is out of market because it is a flat price regardless of when it is produced or, for that matter, fails to reflect that many hours of the day that solar panels produce absolutely nothing. It is hard to avoid the conclusion that on an economic basis, the NEM-derived price paid for solar DG energy completely misses the value of solar during most hours of the day. Interestingly, part of the cause for this incorrect valuation is that rooftop solar units have generally been installed facing south, as opposed to west. Because demand peaks have been trending later in the day (as illustrated in the California and New England figures below), this southern exposure has proven to render peak production for solar even less coincident with demand. Had the appropriate market prices been in effect, it is highly unlikely that such a costly error would have occurred.

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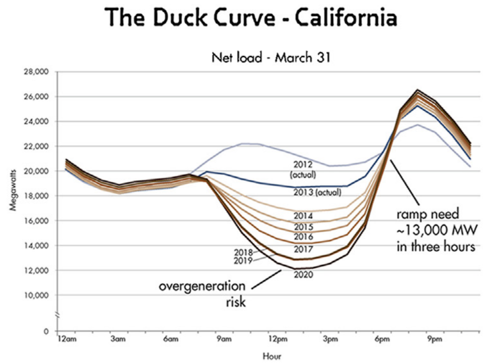
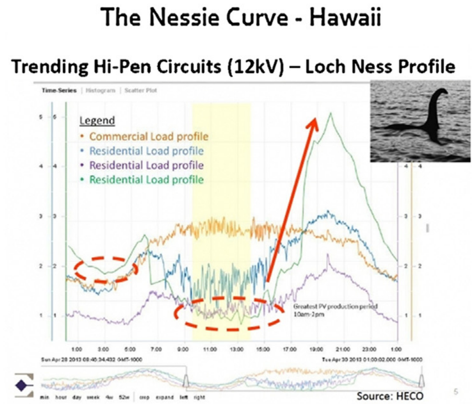


http://www.caiso.com/Documents/FlexibleResourcesHelpRenewables_FastFacts.pdf



www.greentechmedia.com/articles/read/hawaiis-solar-grid-landscape-and-the-nessie-curve.

Figure 2: Ramping Needs Increased Due to Lack of Solar Prodution During Peak Demand

As is dramatically illustrated in the graph at left in Figure 2, enticed by a number of factors, not the least of which is net metering, substantial investment in the growth of solar capacity in the Golden State has enormously magnified the need for additional fossil plants, operating on a ramping basis, to compensate for the dropoff in solar production at peak. In that context, the absence of any meaningful signal to make solar more efficient (e.g. linking it with storage) is simply something that can no longer be tolerated. Not coincidentally, the charts from both the California and New England ISOs (found further *infra*), as well as that from DTE, illustrate the wisdom of compensating solar DG at LMP, so its price accurately reflects its value at the time of actual production and avoids requiring non-solar customers to pay prices for energy that far exceed its value.

A. Capacity value

The capacity value of a generating asset is derived from its availability to produce energy when called upon to do so. If a generator is not available when needed, it has little or no capacity value. By its very nature, solar DG on its own, without its own backup capacity (e.g. storage), can only produce energy intermittently. It is completely dependent on sunshine. Unless sunshine is guaranteed at all times solar DG is called upon to produce, it cannot be relied upon to always be available when needed. Moreover, even if all days were reliably sunny, the energy derived from the sun is only accessible at certain times of the day. In many jurisdictions, the presence and potency of sunshine is not coincident with peak demand. Frequently, for example, solar DG capacity is greatest in the early afternoon, while peak demand occurs later in the afternoon or in early evening. The two charts in Figure 3 illustrate the lack of coincidence of solar production and peak demand in New England.[1]

These two charts dramatically demonstrate that, on the days chosen as representative of summer and winter in New England, solar PV is completely absent during the winter peak, reaches its peak production as peak demand is rising in the summertime, and drops off dramatically during almost the entire plateau period when demand is at peak. It should also be noted that on the days chosen, the sun was shining. The graph, of course, would look very different on cloudy days when solar production is virtually nil.

The Electric Power Research Institute (EPRI) graphs in Figure 4 reveal similar patterns on a national level. The first graph

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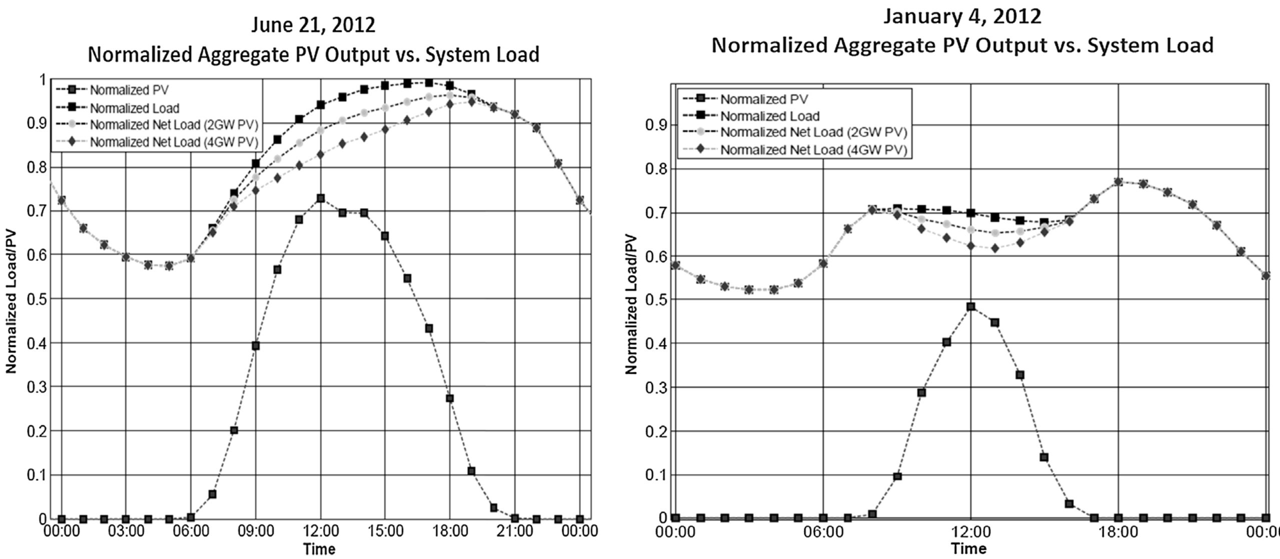

Figure 3: Lack of Coincidence of Solar Production and Peak Demand in New England

depicts the peak load reduction and ramp rate impacts resulting from high penetration of solar PV. The second illustrates the fact that because residential load and PV system output do not match, solar DG hosts use the grid for purchasing or selling energy most of the time.

As noted above, providers of capacity in the wholesale market may also have availability issues. In their case, however, if they are not available when called upon to produce, they are typically obligated to either provide replacement energy or to pay the

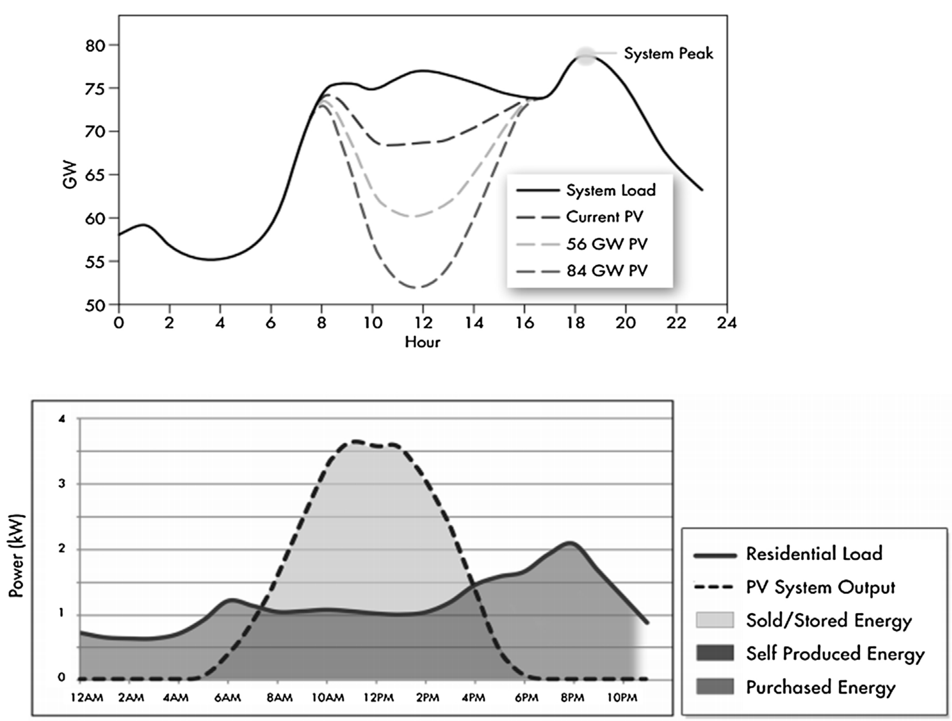

Figure 4: Increased Ramp Rates, Peak Load Reduction and Reliance on the Grid

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marginal cost of energy that they failed to deliver. Unless a similar obligation is imposed on solar DG providers, the capacity value of solar DG is reduced even further. Good pricing policy would suggest that DG prices should be fully reflective of the value of the type of capacity that is actually provided. As currently implemented, net metering does not adequately reflect how the capacity availability measures up to demand.

B. Availability and reliability

Many advocates of solar DG assert that it enhances overall reliability because the units are small, widely distributed but close to load, and not reliant on the high-voltage transmission system. It is argued that they are less impacted by disasters and weather disturbances. At best, these claims are highly speculative and, for the reasons noted below, quite dubious. It would be a mistake to attribute added value to solar DG because of reliability.

Solar DG is subject to disaster as much as any other installations. High winds, for example, can harm rooftop solar as much as any other facility connected or unconnected to the grid. Cloudy conditions can disrupt solar output while not affecting anything else on the grid.

Solar DG has more reliability benefit in some places than others. In Brazil, for instance, a system that largely relies on large hydropower plants with large storage reservoirs, solar has considerable long-term reliability value because whenever it generates energy it conserves water in the reservoirs, thereby adding to the reliability of the system. However, in a thermal-dominated system (like much of the United States), where there is little or no

storage, reliability has to be measured on more of a real-time basis. Therefore, solar's intermittency makes it unable to assure its availability when called upon to deliver energy. Indeed, it is far more likely that a thermal unit will have to provide reliability to back up a solar unit than the other way around.

It is also important to examine rooftop solar reliability issues in two contexts: that of the individual customer and that of the system as a whole. Solar DG vendors, as part of their sales pitch, claim that reliability is increased for a specific customer with a rooftop solar unit because on-site generation provides the possibility of maintaining electric power when the surrounding grid is down. When the sun is shining, this claim may be true. Conversely, without the sun, the claim has no validity. However, that argument only applies to the solar host.

On a technical point, a power inverter is an electronic device or circuitry that changes direct current to alternating current. During a system outage the power inverter is automatically switched off to prevent the backflow of live energy onto the system. That is a universal protocol to prevent line workers and the public from encountering live voltage they do not anticipate. Thus, if a solar DG unit is functioning properly, when the grid is down, the solar DG customer's inverter will also go down, making it impossible to export energy. If the solar DG unit is not functioning properly, then the unit may be exporting, but will do so at considerable risk to public safety and to workers trying to restore service. The result is that the solar panel provides virtually no reliability to anyone other than perhaps to the solar host.

Attributing reliability benefits to an intermittent resource is a stretch. By definition, intermittent resources are supplemental to baseload units. The only possible exceptions to that are, as noted above, where there are individual reliability benefits or where the availability of the unit is

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coincident with peak demand or has the effect of conserving otherwise depletable resources. Absent those circumstances, and absent storage, it is almost certainly the case that the system provides reliability for solar DG, rather than the other way around. That is particularly ironic given that in the context of net metering, solar DG hosts do not pay for that backup service while generating electric energy. In essence, in a net metering context, non-solar customers pay solar DG providers for reliability benefits that solar DG does not provide them, while solar DG customers do not pay for the reliability benefits they actually do receive.

From an investment perspective, solar DG pricing methods, like NEM, which redirect distribution revenues from distributors to solar PV providers who offer no distribution services are detrimental to reliability as they either deprive the sector of capital needed to maintain high levels of service or demand additional revenues from non-solar DG users who would ordinarily not have to pay such a disproportionate share of the costs. For utilities, the diversion of funds leaves them with a Hobson's choice of either delaying maintenance and/or needed investment, or seeking additional funds – in effect, a cross-subsidy from non-solar users. It is also relevant to reliability to again note that the prevalence of intermittent resources on the grid, including solar DG, may well cause new, cleaner, and more efficient generation to appear less attractive to investors. Over the long term, that effect could lead to reliability problems associated with inadequate generating capacity, especially at times of peak demand.

C. Solar DG does not avoid transmission costs

It is nearly impossible to demonstrate that solar DG will obviate the need for transmission, much less quantify the cost savings associated with this purported benefit. Of course, there is a simple way to calculate any actual transmission savings, and that is by compensating solar DG providers in the organized markets at the locational marginal cost of electricity at their location. That compensation model would have the benefit of capturing both the energy value and the demonstrable transmission value of solar DG. Absent that formulation, efforts to calculate actual transmission savings would be a difficult, perhaps entirely academic, task.

Solar DG advocates assert that real transmission savings are achieved through the deployment of DG, especially in systems that use locational marginal cost pricing. The argument is that by producing energy at the distribution level, less transmission service will be required, thereby reducing or deferring the need for new transmission facilities. It is also often contended that DG will reduce congestion costs, and perhaps even provide some ancillary services. All of that is theoretically possible but certainly not uniformly, or even inevitably, true.

Of course it is true that DG, absent any adverse, indirect effect it might have on the operations of the high-voltage grid, does not incur any transmission costs in bringing its energy to market. However, that is quite different than asserting that DG provides actual transmission savings. In fact, it would be incorrect to simply conclude across the board that solar DG will achieve transmission savings. It is possible that there could be transmission savings associated with solar DG deployment, but that can only be ascertained on a fact- and location-specific basis. Such savings would most likely be derived from reducing congestion or providing ancillary services of some kind. It is also theoretically

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possible, but highly unlikely, that massive deployment of solar DG will eliminate (or, more likely, defer) the need to build new transmission facilities. For a variety of reasons, including the complexities of transmission planning, the time horizons involved, the complex interactions of multiple parties, and economies of scale in building transmission, it is improbable that solar DG actually saves any investment in transmission capacity.

Indeed, a mere glance at the California ISO duck graph showing the need for ramping capacity to make up for the intermittent availability of solar DG provides a *prima facie* case for believing that the opposite is true and that solar DG may cause a need for more transmission to be built. These and other charts also show that as long as solar does not reduce peak energy use, transmission is likely needed to serve peak hours. Regardless, it is virtually impossible to demonstrate that, other the possibilities of reducing congestions costs (a value fully captured by LMP), there is very little likelihood of transmission saving being derived from solar DG.

D. Solar DG does not avoid distribution costs

It is more likely that solar DG will cause more distribution costs than it saves. That is because these generation sources could change voltage flows in ways that will require more controls, adjustments, and maintenance. Moving from a one-way to a two-way system will certainly increase the need for technical equipment to manage the reliability of the system. While DG solar may not be the only cause of this move the intermittent nature of solar makes

it particularly difficult to manage. It will also inevitably increase transaction costs for the utility to execute interconnection agreements and do the billing for an inherently more complicated transaction than simply supplying energy to a customer. It is impossible, unless a solar DG host leaves the grid, to envision a circumstance where solar DG would effectuate distribution savings.

Regarding distribution line losses, DG offers value only to DG providers when they consume what they produce because any DG output exported to the system is subject to the same line loss calculations that any other generator experiences. If there were locational prices on the distribution system, there might be line loss benefits that could be captured by DG but, since those price signals do not exist, the argument is purely academic.

VII. Lower Hedge Value

The theory advanced by some solar DG proponents is that because the marginal cost of solar is zero, it serves as a hedge against price volatility. In theory, that might make sense. In reality, however, solar is an intermittent resource that cannot serve as a meaningful hedge unless such zero-cost energy is both sufficiently and timely produced. Thus, solar DG is the equivalent of a risky counterparty whose financial position renders him incapable of assuring payment when required. Moreover, the value of a hedge depends on the amount of money the purchaser of the hedge is obliged to pay for the insurance and the amount and probability of the price he/she seeks to avoid paying. With a NEM system (or the high-priced ''value of solar'' approach that solar DG advocates seek), the price paid is highly likely to exceed the fuel or energy price most utilities would hedge against. In short, the argument ventures into the realm of the absurd. It amounts to: *Pay me a fixed price that is higher than the price you want to avoid, in order to avoid price volatility*.

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The argument that solar DG provides a valuable hedge function is reduced to virtual absurdity by the fact that the so-called hedge is not callable. In short, if the price rises to the level against which the hedge purchaser wants to be insured against, the solar provider of the hedge is not obliged to pay. That being the case, there is no hedge whatsoever.

VIII. Effects of Solar DG on Other Renewable Resources

A. Impact of a low capacity factor

Since 2008, as Figure 5 from the United States Energy Information Administration (EIA) points out, solar PV has had the lowest capacity factor of any commonly used renewable energy resource in the U.S. It is also worth noting that while the overall costs of installing solar panels has declined (as noted above) the productivity of solar PV has remained constant at consistently low levels. It should be noted that the chart below compares only ''utility-scale'' projects. As noted in the Lazard study above, distributed solar is even less cost effective than utility-scale solar, which already occupies last place on the Department of Energy (DOE) ratings.

The stark reality of solar PV's combination of high prices and poor capacity factor carries over into the cost of reducing carbon emissions. An interesting dialog occurred recently between Charles Frank, an economist at the Brookings Institution, and Amory Lovins of the Rocky Mountain Institute.[2] Their dialogue, while contentious on many points, reflects similar views on the realities depicted in the EIA chart. Frank analyzed five non- or low-emitting generation resources by their cost effectiveness in reducing carbon and concluded that nuclear and natural gas, followed by hydro, wind, and solar were, in that order, the most cost-effective types of generators for reducing carbon. Lovins took issue with Frank for using outdated data and for not looking at energy efficiency. He also argued that nuclear ranked last in cost effectiveness, and expressed some reservations about the ranking of natural gas. However, what is significant is that, among renewable resources, Lovins concurred with Frank that solar DG is the least efficient renewable resource for reducing carbon. Thus, in the view of both men – who hold quite divergent views on how best to reduce carbon emissions – not only is solar DG expensive, it is the least cost-effective renewable resource for reducing carbon emissions.

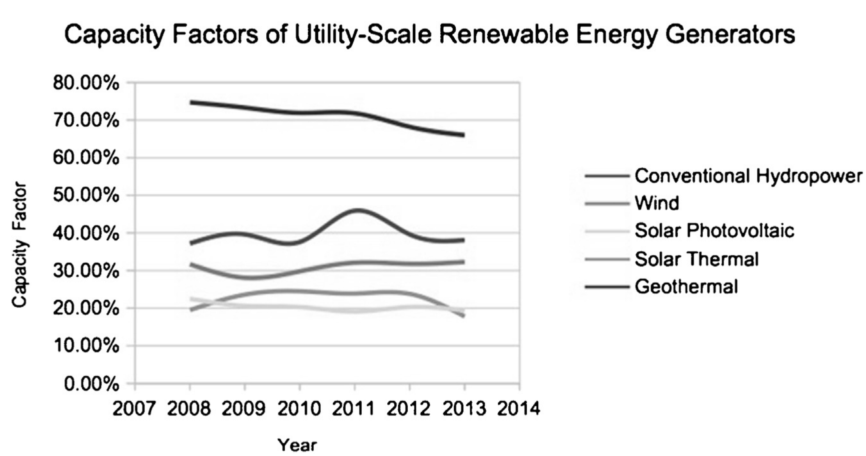

Figure 5: Capacity Factors of Utility-Scale Renewable Energy Generators

B. Impact of higher-than-market price

Higher-than-market prices paid for solar DG has adverse effects on other renewable resources. All wholesale generators, renewable and otherwise, have to incorporate transmission and distribution costs into the price of energy delivered to customers. As mentioned above, it is true that transmission issues play out differently for distributed generation than for wholesale generation. Since DG, by definition, does not rely on transmission capacity, although DG might impact congestion costs in various ways, wholesale energy's delivered cost reflects transmission capacity

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costs while DG's does not. Thus, any competitive advantage for DG on that score is quite natural. However, under the net metering scheme, DG providers also do not have to incorporate distribution costs into their end product, and that results in a serious economic distortion of the generation markets in general as well as specifically in renewable markets. In fact, as noted *supra*, solar DG providers under NEM are actually paid for delivering their energy even though they provide no such service. Wholesale generators, unlike their DG counterparts, enjoy no such comparable enrichment for service they do not provide. The effect of NEM's highly inefficient and non-cost-reflective rates is to distort market prices in ways that reward inefficiency and will likely distort price signals that are essential for an efficient marketplace.

In addition, at a critical mass, artificially elevated solar DG prices are highly likely to create distortions and inefficiencies in the capacity and energy prices found within organized markets. An environment with two parallel pricing regimes, one market- or cost-based, and the other an arbitrary one neither market- nor cost-based, is simply economically incoherent and unsustainable. The overall effect of net metering is to increase the prices consumers pay for energy overall, without any assurance of any long-term benefit. Solar DG is artificially elevated to a preferential position above more-efficient, larger-scale generation, including all other renewables. The disparity in treatment between solar DG and other forms of energy suggests that net metering is not only federal preemption bait (as further discussed below); it is fundamentally anti-competitive as well. Indeed, it compels consumers to both cross-subsidize less efficient producers and to pay higher prices

than necessary for energy. It will also entice investors to allocate their capital to toward more profitable but less efficient generation. In terms of efficiency and public benefit, the incentives inherent in NEM are simply perverse.

Large-scale bulk power renewables (e.g. large-scale wind and solar farms, geothermal) are put at a particular disadvantage by NEM pricing of solar DG independent of costs or market for two basic reasons. First, large-scale renewables are more efficient and more cost-effective than DG, yet net metering provides a subsidy only to the less efficient form of generation. In fact, solar DG providers are compensated for the energy they export at a price that can range from two to six times the market price for energy. Second, in those states with renewable portfolio standards (RPS), the entry of a critical mass of non-cost-justified solar DG units into the market could have the effect of driving more efficient, large-scale renewables out of a fair share of the RPS market. The effect, in a competitive market, is to bias the market to incentivize highly inefficient small-scale solar to the detriment of less costly larger-scale solar.

C. Comprehensive environmental analysis

Any analysis of the environmental impact of the generation mix should include an examination of the least-cost, most efficient ways to get to the desired results. Problematically, the preferential pricing of less efficient solar DG imposes an unnecessarily high-cost approach to reducing carbon. Results such as that cannot be justified on the basis of externalities, which are no different between DG and larger-scale renewables. Indeed, it seems probable that overpayments for DG have the effect of squeezing more efficient forms of renewable energy out of RPS markets by using preferential pricing to grab a disproportionate share of the RPS market and driving up the cost of reducing carbon.

In the long run, of course, the inherent favoritism in pricing DG

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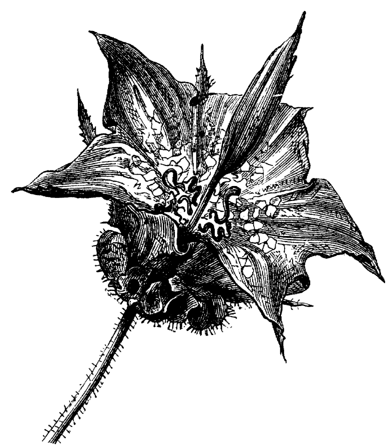
at levels arbitrarily higher than other renewable energy sources does not bode well for either the future of renewables or the objective of efficiently reducing carbon emissions. Discrimination in favor of inefficient resources on a long-term basis is simply not sustainable. The inevitable backlash in both the marketplace and public perception has the potential to sweep away public support for renewable energy and perhaps for strong environmental controls as well, an outcome no one concerned about the environment would want. One of the most notable ironies emanating from the use of net metering to price solar DG is that it will almost certainly lead to changes in retail pricing that will undermine the promotion of energy efficiency. The reason for this is that as solar DG becomes more widely deployed, utilities and their regulators will likely become increasingly concerned with the diminution of revenues required to support the distribution system that is caused by the use of net metering.

Those concerns are derived from the fact that under NEM, when solar DG is being self-consumed at the host premises, no revenues are being paid by that host to the utility for providing what essentially amounts to a battery to supplement their self-generation. Since the costs of the distribution are fixed and not variable with the use of ''behind the meter'' generation, net metering results in a delta of revenue that is either made up for by non-solar customers or constitutes a loss for the utility. Neither outcome is likely to be satisfactory to either the utility or the regulators. Inevitably there will be ratemaking consequences. That problem is compounded, of course, by the fact that when the excess output of rooftop solar is being exported into the grid the solar provider is



being paid as if he/she was delivering the energy, a service obviously provided by the distribution utility. Thus, not only are solar hosts not paying their fair share of fixed costs, they are, by the operation of net metering, actually taking revenues away from the entity that actually provides the service. From the standpoint of the utility and of the non-solar ratepayers who have to bear the burden of such uneconomic and inequitable revenue allocation, rate design remedies will be sought.

One likely remedy to be proposed is to modify the fixed/variable ratio in rates. While distributions are indisputably fixed costs, regulators have generally divided the recovery of those costs on a different basis. Some have been recovered on a fixed basis, while others have been recovered on a variable, volumetric basis. There are two critical policy reasons why this has been the case. The first is that fixed charges tend to impose a disproportionate burden on low-income households and on customers whose consumption is relatively light. The other reason is that volumetric-based charges send a signal to end users that the more they consume, the more they pay. Stated succinctly, the price signal promotes the efficient use of energy. If the revenue stream to cover distribution costs is diminished through mechanisms like net metering, utilities concerned about revenue requirements and regulators, concerned about reliability will, almost inevitably, shift more costs into non-by passable fixed charges, thus imposing more of a burden on low-income households and, equally important, diluting price signals for energy efficiency. In short, net metering will almost certainly, at some point, serve to both cause cost recovery to be socially regressive, and to discourage energy efficiency. In effect, net metering will likely become a classic case of anti-green pricing.

The anti-green pricing aspect of net metering is also exemplified by the behavioral pattern it incents among solar hosts. As shown on both the California and New England

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graphs above, solar production slacks off and ultimately disappears as demand reaches its peak. Despite that, solar hosts are never signaled through prices that their consumption is no longer being supported by zero-marginal-cost solar production. Indeed, in most cases net metering determines prices on an average-cost basis, even though solar production, even in the best of circumstances, is only available a fraction of the time period used for averaging. Thus, solar hosts are essentially lulled into a pattern induced by low marginal prices, which continue in periods of peak demand, thereby driving the peak demand even higher, a result that is truly perverse, both economically and environmentally. In short, net metering and energy efficiency are simply not compatible.

D. Net metering and energy efficiency are incompatible

Many experts from all facets of the renewable energy discussion will assert that energy efficiency is an important, if not the most important, means to increase carbon reductions. Assuming those experts are correct, it is important to consider the ways in which net metering impacts incentives for energy efficiency. While solar DG and energy efficiency are not inherently anathema, net metering is not compatible with energy efficiency. As discussed above, net metering is a compensation mechanism that causes utilities and regulators to move costs into the fixed category, thereby diluting the price signals that would encourage energy efficiency.

E. Possible federal preemption

State regulators, in setting prices for solar DG, should also be

conscious of the potential for jurisdictional disputes should DG prices cause any dislocation in wholesale markets. Because of the economic distortions caused by NEM, there are some who are calling for DG to be under the control of the Federal Energy Regulatory Commission (FERC) rather than state public utilities commissions' jurisdiction.[3] Unless states begin to remedy the price distortions inherent in net metering, it would be surprising if many aggrieved wholesale generators did not seek relief from FERC. In a somewhat analogous situation, New Jersey and Maryland sought to use state subsidies/mandates to support the construction of new power plants in order to manipulate and/or bypass the PJM capacity market. FERC, in a decision which was later affirmed by the Third Circuit Court of Appeals, struck down the state program by preemption. State commissions that continue to prop up a net metering regime with no basis in either market-based pricing or cost-of-service regulation may well discover the prospect of preemption hanging over them.[4] Further foreshadowing preemption are several other examples of state net metering programs running contrary to federal pricing regimes.

The Public Utility Regulatory Policies Act (PURPA) places an avoided-cost ceiling on power purchases; net metering evades that ceiling. Under net metering arrangements, not only are purchases of excess power mandated at levels well in excess of avoided costs, but they also include a cross-subsidy from non-solar customers for the distribution costs of solar DG providers. Bulk power renewables are subject to all of the rules of the wholesale market, which may include such costs as congestion costs, ancillary services, penalties for no availability, and others. Under net metering, solar DG providers are subject to none of these disciplines. In addition, some wholesale renewable generators complain that the arbitrarily high prices paid under net metering have the effect of attracting enough solar DG providers to fill up the RPS market, so that they

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are being effectively squeezed out of the portfolio entirely.

What is particularly ironic about this effect is that, as noted above, distributed, small-scale solar is the least efficient form of commonly used renewable energy sources in the United States. All of these factors indicate that an increasing number of parties are likely to be motivated to ask FERC to preempt net metering and other state-mandated regimes that allow for unreasonably discriminatory and anti-competitive pricing.

IX. Factors Mitigating Environmental Benefits

Expectations of environmental externality benefits may be the biggest motivator for supporting and subsidizing solar DG. Proponents of solar DG note that solar has zero carbon or other harmful emissions from the process of producing energy. Additionally, to the extent that wide deployment of solar PV avoids the need to invest in technologies that do have carbon and other undesirable emissions, there is an environmental benefit that avoids the social costs associated with pollution. In the absence of legal limits on relevant emissions such costs, solar DG advocates correctly point out, are not captured in the internalized costs of the competing technologies. Therefore, solar DG advocates suggest that regulators and policymakers should take these external social costs into consideration in setting prices for various forms of energy.

The use of external social costs, as opposed to solely the internalized economics of various forms of energy is a controversial subject. Many oppose the use of externalities as a factor in pricing because it distorts the market and makes social judgments economic regulators may not be empowered to make. In the views of such opponents, the only externalities that ought to be incorporated into pricing are those that are internalized by legal mandate. Proponents of incorporating externalities into rates contend that doing so is the only way to accurately reflect all social costs. They also contend that factoring in environmental externalities is a form of insurance against future regulatory requirements. While this article takes no position as to the merits of incorporating externalities into ratemaking, it will address this issue, on the assumption that at least some regulators and policymakers will look at externalities for purposes of assessing the value of solar DG.

Before delving into this issue any further, it is important to note that the United States Environmental Protection Agency (EPA), whose jurisdiction over carbon emissions has been affirmed by the U.S, Supreme Court,[5] has proposed new rules under Section 111(d) of the Clean Air Act that would, if promulgated, internalize the costs of carbon into electricity ratemaking, so the issue of whether or not to consider the costs of carbon would no longer be debatable. Thus, there is a great deal of uncertainty which, in the short term, effectively strengthens the hand of those who contend consideration of carbon emissions would be a form of insurance against future regulation. In the longer term, however, the likelihood that carbon emissions will be internalized gives rise to very serious questions as to the value of including externalities which, over time may run contrary to the economics of internalized carbon costs. It is also worth noting that there are already several states that have adopted controls on carbon emissions. In those states, it is especially important to make certain that renewable policy and pricing enhances efficiency in compliance, as opposed to confusing means and ends. Regardless, the environmental issue, in terms of solar DG, is

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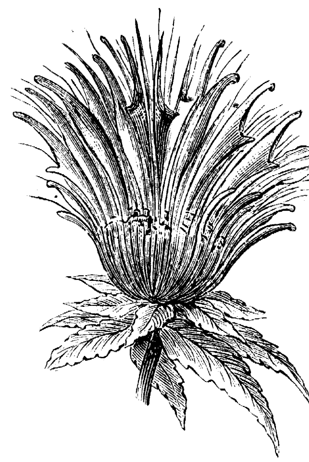
how cost effective such installations are for reducing carbon.

There is little dispute that solar DG is the least efficient of all renewable energy resources in common use in this country. As noted, there is even a consensus, which includes Amory Lovins, that agrees that solar DG is the least efficient renewable resource for reducing carbon. That view is fully supported by the facts in the California duck graph, as well as the ISO-New England and EPRI Value of the Grid data, which demonstrate conclusively that solar DG is consistently off-peak. When priced at net metering levels, it is also the most expensive renewable resource, thereby producing a perverse paradigm that where the least efficient resource costs the most. Therefore, it is evident, without considering any other factors, that solar DG is the least cost-effective use of renewable energy to reduce carbon emissions. There is also the reality that, as a general rule the least efficient and ''dirtiest'' plants are most likely getting dispatched at times of peak demand. Thus, in the rare instance that solar DG is available at peak in the United States, it is not displacing the most carbon emitting plants. Instead, it is displacing more efficient, less polluting generating units. Moreover, as an intermittent resource, its availability is highly uncertain and fossil plants are often called upon to operate on a less efficient, more carbon-emitting basis than if they were running as pure baseload. Thus solar DG is not only expensive, it is also much more likely to displace low-emitting, more efficient generation than less efficient, dirtier units. In addition, as noted earlier, net metering significantly dilutes the price signals for environmentally benign energy efficiency.



Those conclusions have been borne out by developments in Germany. In that country, where there has been a very dramatic increase in reliance on intermittent energy, prices have risen 37 percent since 2005, and were accompanied by spikes in both carbon emissions and the use of brown coal (lignite). While there are very significant difference between most states and Germany, perhaps most notably that Germany has decided to close down its nuclear plants (although it has replaced much of the domestic nuclear with imported nuclear energy), the experience in that country is very telling.[6] The German example clearly demonstrates that increased dependence on renewable energy resources, particularly intermittent resources, does not, as many solar DG proponents claim, *ipso facto*, mean fewer carbon emissions, and may, in fact, cause the opposite to occur. It also demonstrates that prices will escalate dramatically if the feed in tariffs are as far in excess of market as NEM prices are, as shown by the DTE graph above. The Germans, incidentally, have recognized their miscalculations and are dramatically recalibrating their strategy.

X. Regressive Social Impact

There are social effects beyond the environment that have to be taken into account if externalities are to be factored into ratemaking. Any failure to examine environmental externalities without recognizing that there are other social externalities to be considered as well will yield highly skewed results. Perhaps the most important of those is the social impact.

The social impacts of solar DG are caused by three main factors. First, as noted above, solar DG users have their electricity costs cross-subsidized by their neighbors who completely rely on the grid. Second, some data suggests that solar DG users are unusual electricity users. Third, not everyone can afford to be a solar DG user. To address the second point, unlike typical residential customers, in some regions solar

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DG users use little or no grid power at midday but quickly ramp up demand on peak, when PV production wanes (as is demonstrated by the charts in from the New England and California ISOs). Utilities must be able not only to serve full load on days when solar PV is not performing, but also to ramp up resources quickly to address the peak created by solar DG users. In order to ramp up as needed, utilities will purchase energy at the marginal price and then distribute those costs across all users, not just solar DG users. Thus, users without solar DG may be penalized for the use patterns of their solar DG neighbors. A comparison of residential electricity consumers in the western United States may be found below in **Figure 6**.[7]

Further, the impact of net metering is not simply the creation of a cross-subsidy from non-solar PV customers to solar PV customers but, as has been pointed out in a recent study by E3,[8] it is a cross-subsidy from less affluent households to more affluent ones. Indeed, the average median household income of net energy metering customers in California is 68 percent higher than that of the average household in the state, according to the study. In a recent proceeding, the staff of the Arizona Commerce Commission noted the same consequence.[9] As one wry observer in California noted, net metering is not ''Robin Hood'' but rather it is ''robbin' the hood.'' In order to install rooftop solar panels, often individuals must be homeowners with high credit ratings or sufficient capital. Leasing arrangements are also widespread, but are generally available only to customers who own their own premises and they require the assignment of most of the rooftop solar benefits to the lessor. Many electricity customers, particularly less affluent ones, do not own homes or lost their homes in the most recent recession. The electricity customers who are unable to afford rooftop solar are forced to subsidize those who are already in a more favorable financial position. Thus, it is entirely fair to characterize NEM as a wealth transfer from less affluent ratepayers to more affluent ones.

Tariffs with a regressive social impact are certainly worthy of consideration from a policy and rate-making perspective. Thus, if externalities are to be weighed in setting pricing for solar DG, then it is important to avoid inordinate cost shifting and, in particular, to avoid adding new burdens to the less affluent in order to provide benefits to those further up on the income scale.

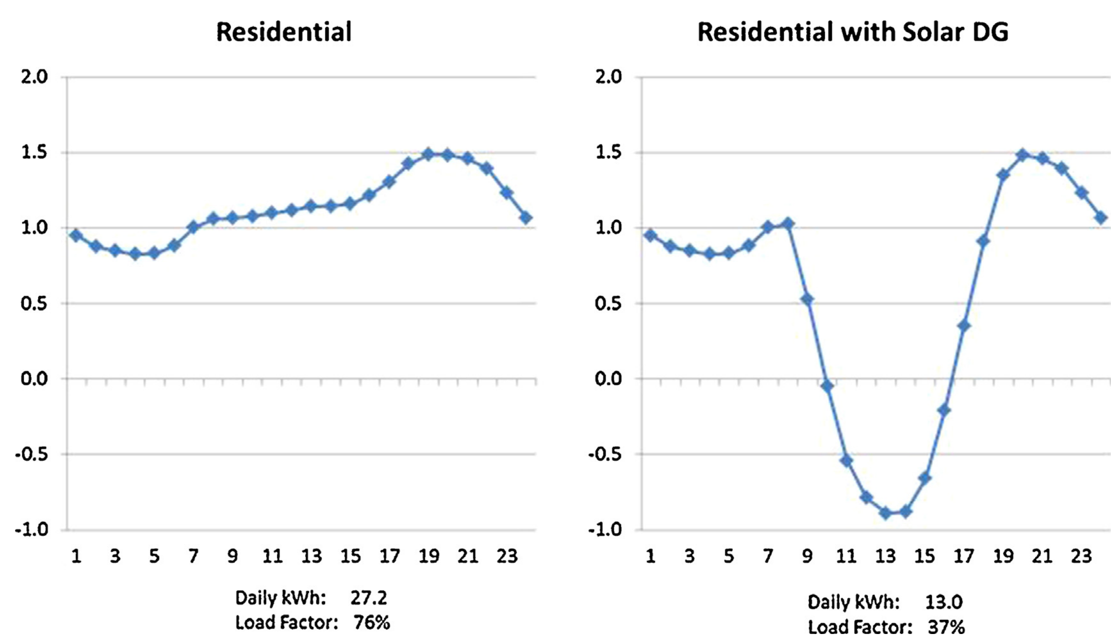

Figure 6: Typical Residential Loads Average Day – Iowa

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XI. Impact on Job Creation

The impact of solar PV on jobs is often cited as an externality benefit. Any analysis of the job impact must be comprehensive and not an effort to cherry pick data. For instance, merely citing the number of solar installers employed does not tell us much. Many aspirations for more jobs manufacturing PV units in the United States have not materialized due to China's capture of the market. Other impacts to be considered are the effect of solar PV on electric rates and the impact of that on the job market, not only in terms of what happens with rates, but also in terms of the rate structure that is implemented as a result of more market penetration by solar DG. For example, it is conceivable that any movements toward more fixed costs could discourage energy efficiency work thus displacing jobs in manufacturing and installing energy efficiency technology.

XII. Conclusion

There is value in solar DG, but that value is severely diminished and placed in peril if its pricing discourages efficiency improvements and distorts critical price signals in the marketplace. It is similarly counterproductive to the future of solar DG if its pricing has socially regressive effects and if it sucks needed revenue away from the essential distribution grid. From an economic point of view solar DG has energy value, the potential for reducing some transmission costs, and perhaps under the right circumstances, some capacity value, and ought to be compensated accordingly. With regard to externalities, it is not entirely clear, when viewed in the entire scope of its impact, that solar DG, has positive environmental value, but it is absolutely

clear that when net metering is deployed, it is simply not a cost-effective means for reducing carbon emissions. In fact, it is possible that solar DG might do more harm than good if it has the effect of removing price incentives for energy efficiency, and if it causes older plants to extend their lives and to operate inefficiently on a ramping basis for which they were not designed. It seems clear that if we are to capture the full value of solar DG, net metering must be discarded and replaced with a market-based pricing system that values the resource appropriately and includes incentives for making it more efficient over the long run.■

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4. 135 FERC 13 61,022, April 12, 2011 *affirmed* New Jersey Board of Public Utilities et al. v. FERC, 744 F.3d 74 (2014).

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