BEFORE THE STATE CORPORATION COMMISSION

OF THE STATE OF KANSAS

DIRECT TESTIMONY

OF

AHMAD FARUQUI

ON BEHALF OF

WESTAR ENERGY

DOCKET NO. 15-WSEE-115-RTS

I. INTRODUCTION

Q. WHAT IS YOUR NAME AND ADDRESS?

A. My name is Ahmad Faruqui. I am a Principal with the Brattle Group, an economics consulting firm. My address is 201 Mission Street, Suite 2800, San Francisco, California 94105.

Q. ON WHOSE BEHALF ARE YOU SUBMITTING TESTIMONY?

A. I am testifying on behalf of Westar Energy, Inc. (“Westar”).

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to propose modifications to the existing rate design for residential customers and to introduce some new rate designs.

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. It is organized into several sections. Section II presents my qualifications. Section III presents an executive summary. Section IV reviews the principles of rate design. Section V presents the rate design proposals. Section VI discusses the impact of the new rates. And Section VII concludes the testimony.

II. QUALIFICATIONS

Q. WHAT ARE YOUR QUALIFICATIONS AS THEY PERTAIN TO THIS TESTIMONY?

A. I have 35 years of consulting and research experience in rate design. In my career, I have analyzed and evaluated a wide range of rate designs for more than one hundred clients in the United States and abroad. I have authored or co-authored more than one hundred papers on rate designs and related issues and co-edited three books on pricing and customer choice.

I hold bachelor's and master's degrees in economics from the University of Karachi, Pakistan, a master's degree in agricultural economics and a master's degree in economics, both from the University of California at Davis, and a doctoral degree in economics also from the University of California at Davis. My resume is included as Appendix A to this testimony.

III. EXECUTIVE SUMMARY

Q. HOW WOULD YOU SUMMARIZE YOUR TESTIMONY?

A. To ensure that the principle of cost-causation is reflected in Westar's rates for residential customers, and to reduce or eliminate inter-customer inequities, the company is proposing to offer three rate design choices to all residential customers without distributed generation (DG) and to offer two of those rate design choices to those residential customers that have DG.[1] The three residential rate design choices that will be offered to customers who don't have DG include (1) the current two-part rate with a monthly basic service fee and a volumetric charge – the "Residential Standard Service" or RSS, (2) a new two-part rate with a higher monthly basic service fee

[1]Throughout my testimony, when I refer to customers who have DG this includes both residential customers who own the DG as well as those who have leased it.

that is more cost-based than the current rate and a lower volumetric charge – the “Residential Stability Plan” or RSP, and (3) a new three-part rate with the monthly basic service fee at the same level as the RSS, a demand charge and a lower volumetric charge – the “Residential Demand Plan” or RDP. New residential customers who have DG will be offered either the RSP or the RDP plans (Nos. 2 and 3 above, respectively) and will not be eligible for the RSS rate offering in order to reduce the subsidy created and imposed on customers that do not have DG resources. As I describe later in my testimony, the majority of the utility's costs are fixed or driven by peak demand rather than total energy consumption. Generation, transmission, distribution and customer service costs to serve all customers and these costs will not significantly decrease as a result of DG adoption. Absent effective rate design, these costs are shifted to and recovered from all customers, the vast majority of whom are not DG customers; meaning that non-DG customers end up subsidizing customers with DG resources.

To move rates gradually toward the actual cost of providing service, Westar is also proposing to increase the monthly basic service fee on the RSS rate offering from $12 to $15. The RDP rate offering was created with a $15 monthly basic service fee to be effective with the rate order in this case. Westar is also proposing to further increase the monthly basic service fee on both of these rate offerings by three dollars each year for the next four years, moving monthly basic service fees more in line with fixed costs. Over that same period, Westar would reduce the energy charge under the RSS and RDP rate offerings to remain revenue neutral for the class as a whole. This four year plan is offered to move rates closer to cost of service while ensuring that the principle of gradualism is observed.

IV. PRINCIPLES OF RATE DESIGN

Q. WHAT ARE THE GENERALLY ACCEPTED RATE DESIGN PRINCIPLES FOR ELECTRICITY?

A. The principles that guide electric rate design have evolved over time. Many authorities have contributed to their development, beginning with the legendary rate engineers John Hopkinson and Arthur Wright in the late 1800's.[2] Their thinking on the subject led them to propose a three-part tariff, consisting of a fixed charge, a demand charge and an energy charge. The demand charge was based on the maximum level of demand which occurred during the billing period. In some versions of the tariff, the energy charge could also feature seasonal or time-of-use variation that corresponded to the variation in the cost of energy supply.[3]

---

[2] See, for example, D.J. Bolton, *Electrical Engineering Economics, and Vol. 2: Costs and Tariffs in Electricity Supply*, (London: Chapman & Hall, Ltd., 1951), at p. 190.

[3] 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).

Q. HAS A THREE-PART TARIFF BEEN WIDELY APPLIED TO ALL CLASSES OF CUSTOMERS?

A. No, not at most utilities. Largely because of lack or expense of necessary metering, the three-part tariff has typically been applied to medium and large commercial and industrial customers, where the amount of electricity demand more easily justifies the investment in meters which measure both demand and energy. For residential and small commercial customers, a two-part tariff has been deployed because those customers typically lacked a demand meter. This two-part tariff, consisting of a customer charge and an energy charge (Schedule RS), is available to Westar's residential customers today.

Q. WHAT MODIFICATIONS, IF ANY, HAVE ECONOMISTS MADE TO THE ORIGINAL DESIGN WHICH WAS PROPOSED BY RATE ENGINEERS?

A. British, French and American economists have made enhancements to the original, three-part rate design. These 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.

In 1961, Professor James C. Bonbright coalesced their thinking in his canon, *Principles of Public Utility Rates*[4] , which was

[4] James C. Bonbright, *Principles of Public Utility Rates* (New York, Columbia University Press, 1951).

reissued in its second edition in 1988. Some of these ideas were further expanded upon by Professor Alfred Kahn in his widely cited treatise, *The Economics of Regulation.* [5] While Professor Bonbright's "Principles" go back five decades, they continue to be relevant today and serve as the foundation for reasonable rate design. It is, of course, appropriate to refine these principles to account for marketplace and technological advances that have occurred since his text was published.

Q. WHAT ARE THE MARKETPLACE AND TECHNOLOGICAL ADVANCES TO WHICH YOU REFER?

A. Distributed generation, demand response, proliferation of digital metering technology, and energy efficiency opportunities now play a growing role in the electric industry. Sales growth has slowed down because of these and other factors. As rooftop solar and net energy metering become major factors, the discussions of pricing and structuring the appropriate incentives become increasingly important. Moreover, since the original principles have a fair degree of overlap, they can be compressed into four principles without loss of generality. If we add a new principle dealing with customer satisfaction, e.g., that arising from a choice of different rate options,

[5] Alfred Kahn, *The Economics of Regulation: Principles and Institutions* (MIT Press, June 1988).

we get a new set of five updated rate design principles for guiding the evolution of modern rate design.

Q. WHAT DO YOU CONSIDER TO BE THE UPDATED BONBRIGHT PRINCIPLES?

A. The five updated Bonbright principles are: (1) economic efficiency, (2) equity, (3) revenue adequacy and stability, (4) bill stability and (5) customer satisfaction. The core of these principles continues to be the notion that charges for electricity to customers should reflect cost causation to the utility. Accordingly, a two-part tariff where the fixed charge reflects those costs of providing service that do not vary with usage and the variable charge reflects those energy costs that vary with usage is the appropriate design for residential customers without a demand meter. Such a rate design is often referred to as a straight fixed-variable (SFV) tariff. In the economics literature, it is referred to as non-linear pricing.

Q. A KEY COMPONENT OF AN SFV TARIFF IS THE MONTHLY FIXED CHARGE. HAS THE NOTION OF A FIXED CHARGE RECEIVED WIDESPREAD SUPPORT IN THE ECONOMICS LITERATURE?

A. Yes. The role of fixed charges has been recognized in economics for decades. For example, as early as 1946, Nobel laureate R.H. Coase stressed the importance of fixed charges when he wrote the following passage in a widely cited article[6]:

> A consumer does not only have to decide whether to consume additional units of a product; he has also to decide whether it is worth his while to consume the product at all rather than spend his money in some other direction. … [T]he consumer should not only pay the costs of obtaining additional units of product at the central market, he should also pay the cost of carriage. How can this be brought about? The obvious answer is that the consumer should be charged one sum to cover the cost of carriage while for additional units he should be charged the cost of the goods at the central market. We thus arrive at the conclusion that the form of pricing which is appropriate is a multi-part pricing system (in the particular case considered, a two-part pricing scheme), a type of pricing well known to students of public utilities and which has often been advocated for just the reasons which I have set out in this article.[7]

Q. IS THERE AN OVER-RIDING PRINCIPLE IN RATE DESIGN?

A. Yes, the over-riding principle is that of cost-causation, i.e., that rates should reflect costs. For example, if 60 percent of the costs are fixed and only 40 percent are variable, then rates should recover 60 percent of the revenues through fixed charges and 40 percent through variable charges.[8] Additionally, if the cost of serving customers varies by customer demand, then rates should include a component that reflects the demand placed by the customer on the electric system.

---

[6] R. H. Coase, “The Marginal Cost Controversy,” *Economica*, Vol 13, No 51, August 1946.

[7] Ibid, page 173.

[8] These are illustrative values; for Westar-specific estimates, see the testimony of Westar witness Overcast.

Q. IS WESTAR PROPOSING SFV RATES IN THIS PROCEEDING?

A. No. Westar is proposing to redesign its residential rates to better reflect the relative levels of fixed and variable costs in its operations, but what it is proposing stops short of SFV pricing. Implementing SFV on a flash-cut basis would violate the ratemaking principle of gradualism. Rather than proposing SFV, Westar is proposing changes that will begin to shift fixed costs out of charges that vary with energy consumption.

Q. WHAT PORTION OF WESTAR'S COST OF PROVIDING RESIDENTIAL SERVICE IS FIXED?

A. According to 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 Dr. Overcast did not study transmission costs because they are generally recovered through Westar's FERC-approved transmission formula and its retail Transmission Delivery Charge, he did testify that virtually all of the costs of transmission are fixed.

Q. WHAT ARE THE FIXED COSTS OF GENERATION?

A. In the case of generation, I am generally referring to 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 control systems and a small amount of variable maintenance.

Q. WHAT ARE THE FIXED COSTS OF TRANSMISSION AND DISTRIBUTION?

A. As with generation, the fixed costs of transmission and distribution are the costs related to constructing the facilities. As indicated by Dr. Overcast, the vast majority of Westar's costs of distribution and transmission are fixed.

Q. WHAT CUSTOMER SERVICE-RELATED COSTS ARE FIXED?

A. 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. These costs are discussed further in the testimony of Westar witness Overcast.

Q. WILL THE RATE DESIGN PROPOSED BY WESTAR ENHANCE THE POTENTIAL TO ACHIEVE THE ECONOMIC OBJECTIVES UNDERLYING CUSTOMER SATISFACTION?

A. Yes. Redesigning rates to better reflect the split between fixed and variable costs in Westar's operations ensures that customers' changes in consumption will directly affect their energy bills. Residential customers will be able to choose the rate that best meets their energy needs.

Q. DOES REDESIGNING RATES TO BETTER REFLECT THE SPLIT BETWEEN FIXED AND VARIABLE COSTS INCENTIVIZE UTILITIES TO SUPPORT ENERGY EFFICIENCY EFFORTS?

A. Yes, it does, by reducing disincentives to the utility under the current rate design. Acceptance and support for services and products that serve to reduce kilowatt-hour consumption, such as energy efficiency services and distributed generation, are more likely to be provided by a utility if its revenues do not depend on the extent of customer usage. If the utility's revenue was entirely recovered through a volumetric charge, then the utility would likely be averse to offering energy efficiency programs because they would impede the utility's cost recovery. Pricing that better reflects the way the utility incurs costs will reduce this disincentive. Similarly, to the extent that public policy is designed to encourage the adoption of clean sources of behind-the-meter distributed generation like rooftop solar, such a rate design helps to address concerns about revenue sufficiency to maintain the investments in generation, transmission, distribution and customer service.

Q. WILL THE REDESIGNED RATES PROMOTE FAIRNESS AND EQUITY?

A. Yes. Each customer imposes costs on the system that are essentially fixed. Under purely volumetric tariffs, customers with lower usage would not be paying their fair share of the cost of creating the utility's generation, transmission and distribution system and providing customer service. Instead, higher use customers would be covering the deficit and paying more than their fair share. Redesigned rates that more closely match fixed and variable costs with fixed and variable charges 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 providing customer service.

Q. WILL THE PROPOSED REDESIGNED RATES PROMOTE THE BONBRIGHT RATEMAKING OBJECTIVE OF CUSTOMER BILL STABILITY?

A. Yes. 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 the hardship of unnecessarily high seasonal bills relative to other times of the year.

Q. SHOULD THE FIXED MONTHLY CHARGE BE LIMITED TO RECOVERING THE COST OF METERS AND SENDING OUT BILLS?

A. No. Suppose a new housing development is being built. Before the homes can be inhabited, Westar must have sufficient generation and transmission capacity to serve the load and must extend its distribution system to the development, including a network of sub-stations, transformers, feeders, and circuits, connect each home to the grid through service drops, and install a meter at each home, among many other activities. These investments must be made before a single kilowatt-hour of electricity is available for consumption by any resident.

Because of the magnitude of the investment associated with providing service to new customers, it is unreasonable to subject the recovery of these fixed costs to the uncertainty associated with energy consumption patterns. It is also unreasonable for customers to pay for these costs through volumetric rates, when the costs themselves are not driven by customers' energy consumption alone but also by the magnitude of customers' kW demand, by the cost of connecting the customer to the grid and the costs of measuring consumption and billing customers for their service. That is the basic rationale for recovering fixed costs through fixed charges and demand charges.

The installation of roof top solar panels provides another example of the rationale for recovering fixed costs through fixed charges. Consider customers who install rooftop solar panels that completely offset their energy consumption over the course of the month. Because the sun doesn't 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.

Under a rate design with no fixed charge component, such customers will pay nothing for delivery service on their electricity bills while still benefiting from using Westar's generation, transmission, distribution, and customer service facilities as backup 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. 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.

Those backup services impose real costs on the utility. It must have generation, transmission, distribution, and customer service available to serve the DG customer when and as needed. Those costs will be borne by other customers under the current rate design. A fixed charge that represents the fixed costs associated with DG customers continuing to be connected to the Westar system would address this inequity. 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 don't have DG.

Q. IF DEMAND METERING IS FEASIBLE, THEN DOES IT MAKE SENSE TO MOVE FROM A TWO-PART RATE TO A THREE-PART RATE BY ADDING A DEMAND CHARGE?

A. Yes, it makes good economic sense where that metering technology is deployed. As I noted earlier, that is how rates have been designed for medium and large commercial and industrial customers since early in the last century. The demand charge would be based on the customer's demand either at the time of system (generation or distribution) peak or it would be based on the customer's maximum demand regardless of time of occurrence. It would be designed to recover those demand-related capacity costs that would otherwise be collected through a fixed charge.

V. THE RATE DESIGN PROPOSALS

Q. WHAT IS WESTAR'S CURRENT RATE DESIGN?

A. Today, Westar offers its residential customers a single two-part rate through Schedule RS.[9] The monthly fixed charge is $12 a month. The variable charge for energy consumption varies by season and is shown in Table 1.

Table 1: Westar's Current Residential Service (RS) Rate

Current Residential Standard Service					
Winter			**Summer**		
Customer Charge	$	12.00	Customer Charge	$	12.00
1st 500 kWh	$	0.064313	1st 500 kWh	$	0.064313
Next 400 kWh	$	0.064313	Next 400 kWh	$	0.064313
All Additional kWh	$	0.052575	All Additional kWh	$	0.075589
Riders (per kWh)					
RECA	$	0.023162			
TDC	$	0.014042			
ECRR	$	0.003910			
PTS	$	0.001961			
EER	$	0.000280			

The customer also pays the riders that are noted at the bottom of the table.[10] This rate applies to all residential customers regardless of whether or not they have DG. The customer charge of $12 covers only a small portion of Westar's fixed customer service costs – Westar witness Dr. Overcast states that Westar could support a monthly basic service fee of $30 based on embedded customer costs alone – much less all the fixed costs of providing service and standing by as a backup provider for DG customers. To account for

[9] https://www.westarenergy.com/Portals/0/Resources/Documents/Tariffs/RS%20eff%2012-2-13.pdf.

[10] A glossary of acronyms is provided in Appendix C.

this, Westar is proposing to change its rate design offerings to the residential class.

Q. WHAT NEW RATE DESIGNS ARE BEING PROPOSED BY WESTAR?

A. To facilitate customer satisfaction with Westar's rate offerings, the company is proposing to introduce new rate choices to its residential customers. These choices embody rate designs that are based on a cost-of-service study that was carried out by Westar witness Dr. Overcast. The choices available to the customer will vary depending on whether or not the customer has DG. It is worth noting that the vast majority of Westar's customers do not have DG. Those customers will have three rate options under the Company's proposal. However, new DG customers will choose between two different rate designs – the second and third options shown in Table 2.

Table 2: Westar's Proposed Rate Designs (2015)

Residential Standard Service					
Winter			**Summer**		
Customer Charge	$	15.00	Customer Charge	$	15.00
1st 500 kWh	$	0.081999	1st 500 kWh	$	0.081999
Next 400 kWh	$	0.081999	Next 400 kWh	$	0.081999
All Additional kWh	$	0.068849	All Additional kWh	$	0.089497
Residential Stability Plan					
Winter			**Summer**		
Customer Charge	$	50.00	Customer Charge	$	50.00
1st 600 kWh	$	0.020000	1st 600 kWh	$	0.020000
Next 400 kWh	$	0.078200	Next 400 kWh	$	0.078200
All Additional kWh	$	0.078200	All Additional kWh	$	0.090000
Residential Demand Plan					
Winter			**Summer**		
Customer Charge	$	15.00	Customer Charge	$	15.00
Energy / kWh	$	0.049000	Energy / kWh	$	0.049000
Demand / kW	$	3.00	Demand / kW	$	10.00
Riders (per kWh) - Applied to All Proposed Rates					
RECA	$	0.023162			
TDC	$	0.014042			
ECRR		-			
PTS		-			
EER	$	0.000280			

Note: ECRR and PTS are accounted for in the energy charge of the proposed rates.

Q. WHAT IS THE "RESIDENTIAL STANDARD SERVICE" (RSS) FOR CUSTOMERS WITHOUT DG?

A. The "Residential Standard Service" or RSS modifies the current two-part rate, Schedule RS, by raising the basic service fee by $3 per month to $15 per month to begin to move it toward current costs. The structure of the volumetric charges remains unchanged other than a slight decrease in the third tier of the summer rate and will be further adjusted based on the revenue requirement established by the Commission's order.

Q. WHAT IS THE "RESIDENTIAL STABILITY PLAN" OR RSP?

A. The "Residential Stability Plan" or RSP has a basic service fee of $50 per month and lower volumetric charges. The basic service fee for the RSP better matches the fixed cost which Westar incurs in serving a residential customer. It also lines up with a national estimate of $51 per month which EPRI estimated in its report on the Integrated Grid.[11]

Q. WHAT IS THE "RESIDENTIAL DEMAND PLAN" OR RDP?

A. The "Residential Demand Plan" or RDP includes a basic service fee of $15 per month, a demand charge of $10/kW-month during the summer and $3/kW-month during the winter, and a year-round volumetric charge of $0.049000/kWh.

As noted earlier in my testimony, 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. It is the standard rate design for medium and large commercial and industrial customers.

[11] EPRI, *The Integrated Grid: Realizing the Full Value of Central and Distributed Energy Resources*, p. 22, Palo Alto: The Electric Power Research Institute, February 2014.

The Residential Demand Plan rate is conceptually similar to Westar's Peak Management rate.[12] The Peak Management rate was first offered in 1981 and has been closed to new enrollment since January 2006 as part of the effort to consolidate rates between Westar's north and south customers. It is referenced in Schedule RS. At its peak enrollment, more than 15,600 customers were enrolled in the Peak Management rate. The number is now closer to around 7,400 because new enrollment has not been permitted for several years and attrition has occurred as customers leave the service territory or switch to the standard rate.

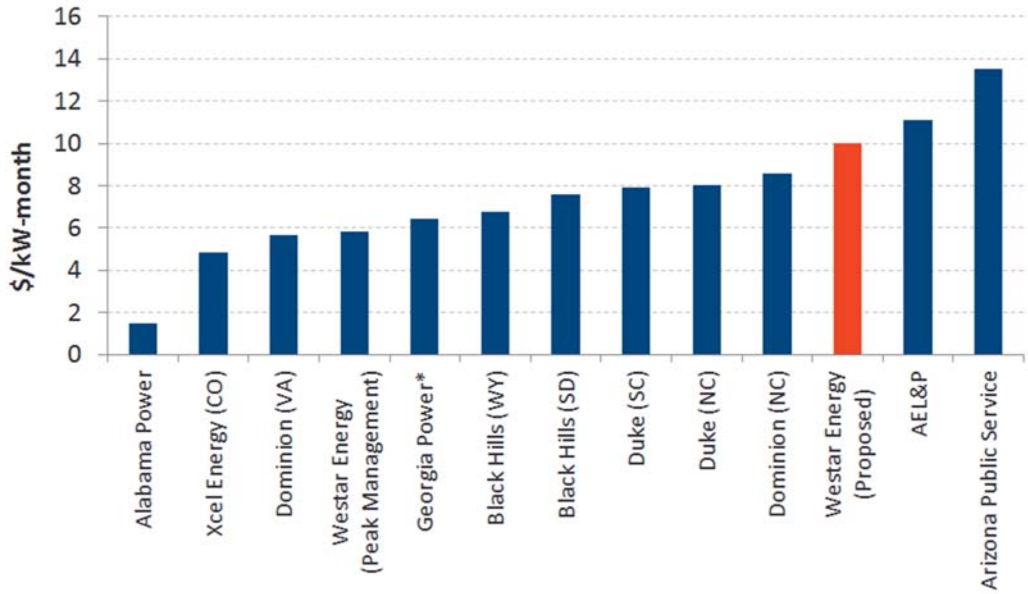
Q. HAVE DEMAND CHARGES BEEN INCLUDED IN RESIDENTIAL RATES OFFERED BY OTHER UTILITIES?

A. Yes, in addition to Westar, there are currently at least nine utilities offering three-part rates to residential customers in a dozen states. Most of these rates have been offered for decades. The utilities currently offering a residential three-part rate are Alabama Power, Alaska Electric Light & Power ("AELP"), Arizona Public Service ("APS"), Black Hills (in South Dakota and Wyoming), Dominion (in Virginia and North Carolina), Duke Energy (in North Carolina and South Carolina), Georgia Power, and Xcel Energy (in Colorado). The rates vary across characteristics such as the timing of demand

[12] The Peak Management rate features a monthly fixed charge of $14.00, an energy charge of 3.9231 cents per kWh, a summer period demand charge of $5.85 per kW and a winter period of $1.80 per kW. The demand charges are assessed on the customer's average kW load during the 30 minute period of maximum use during the month.

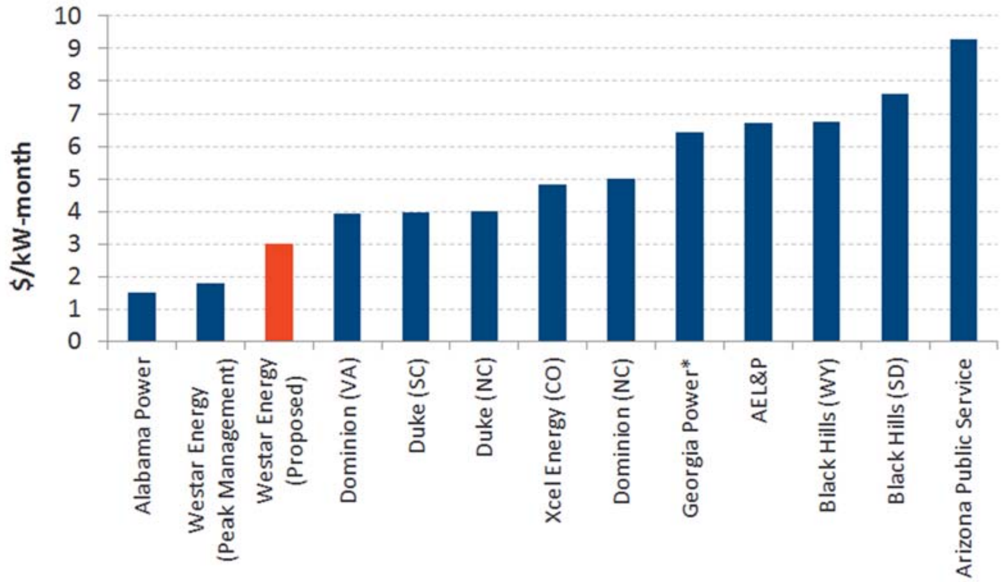
measurement, the duration of the demand interval, and whether the energy charge is time-varying. The demand charges being proposed by Westar in its Residential Demand Plan rate are compared to those of other utilities in Figure 1 and Figure 2.

Figure 1: Summer Demand Charges Offered by Other Utilities



Notes:
Georgia Power's rate is a proposed modification to its existing rate and approval is pending.
Westar's rate is currently closed to new enrollment.
Rates are from utility tariff sheets as of May 2014.

Figure 2: Winter Demand Charges Being Offered by Other Utilities



Notes:
Georgia Power's rate is a proposed modification to its existing rate and approval is pending.
Westar's rate is currently closed to new enrollment.
Rates are from utility tariff sheets as of May 2014.

Q. WILL THE RATES BE MODIFIED OVER TIME?

A. Yes, Westar proposes to transition to a basic service fee of $27 per month in the RSS and RDP by 2019. The fixed charge would increase in increments of $3 in each year in the month of the order date starting in 2016 and ending in 2019 to facilitate a gradual transition to this $27 fixed charge.

Q. WHAT CHOICES WILL BE OFFERED TO DG CUSTOMERS?

A. DG customers will be offered the proposed RSP and RDP rates. For comparison purposes, Appendix C contains a summary of recent activity in other states to update rates for customers who have DG.

Q. WHY WILL DG CUSTOMERS NOT BE OFFERED THE CURRENT TWO-PART RATE?

A. It is important that DG customers pay their fair share of the cost of being connected to the electric grid. The sun does not shine around the clock and solar DG facilities may not meet all of DG customers' needs even at times when the sun is out. When the sun is not shining or is obscured by clouds, DG customers rely on the utility's generation, transmission, distribution, and customer service facilities to light their homes, run their appliances and meet their other needs for electricity. When the sun is shining, DG customers use their generators to meet most of their energy needs. However, DG power will not be able to meet all their energy needs over the course of the entire day.

Under the standard rate, DG customers are allowed to use the utility as a free backup battery. However, the fixed costs of generation, transmission, distribution, and customer service are not avoided by the utility when DG customers' facilities generate. Those costs still have to be recovered, regardless of how much net energy is being drawn by the DG customers.

Under the standard rate, DG customers avoid paying their fair share of fixed costs when they substitute their generation for the utility's. 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 costs of generation, transmission, distribution and customer service that are not being recovered from DG customers when they rely upon such facilities as backup.

Q. HOW DOES WESTAR'S PROPOSED RESIDENTIAL DG RATE OFFERING COMPARE TO THAT OF RECENT PROPOSALS IN OTHER REGIONS?

A. The proposed DG offering compares favorably with the case studies that are included in Appendix C. Most companies offer just a single rate to DG customers, either a higher fixed charge or a three-part rate. Westar is offering two choices and letting them pick the rate that best meets their needs.

VI. THE IMPACT OF THE NEW RATES

Q. HAVE YOU ESTIMATED THE IMPACT OF THE NEW RATES ON CUSTOMER BILLS?

A. Yes, I have. First, I estimated the impact on customer bills if all customers were to remain on the current rate as the fixed charge increases from $15/month in 2015 to $27/month in 2019 (with an offsetting reduction in the volumetric charge). Then I considered the bill impacts if customers were to switch to one of the two alternative proposed rate options. I have chosen 2015 as the starting point for the bill impact analysis, because that is the first year in which the two new rate options are proposed to be offered to customers. Unless otherwise noted, my analysis illustrates bill changes associated with moving from the 2015 rate to the 2019 rate, to fully capture the effects of the proposed rate transition. The analysis assumes no change in the revenue requirement between 2015 and 2019. In other words, it isolates the impacts of offering new rate designs and does not quantify the impact of a change in the average rate level over that four year time period.

Q. WHAT DATA DID YOU USE TO ESTIMATE THESE BILL CHANGES?

A. I began with hourly consumption data for all customers in Westar's load research sample. I used the most recent data available at the time of my analysis, which covers the period from October 1, 2013, through September 30, 2014. I then limited the sample to customers for whom there was a full year of hourly observations in order to accurately account for the annual impact of the new rates.

Then, to ensure that I was only capturing the impact of the rate design changes on customer bills, I modified the rates provided to me by Westar to ensure that they were revenue neutral for the sample customers. I did so by modifying the volumetric charges, while holding the price ratio of the tiers constant, such that the rates would all produce the same revenue for the sample as the 2015 Residential Standard Service rate.[13] A summary of these adjustments is provided in Appendix D. The adjustments account for

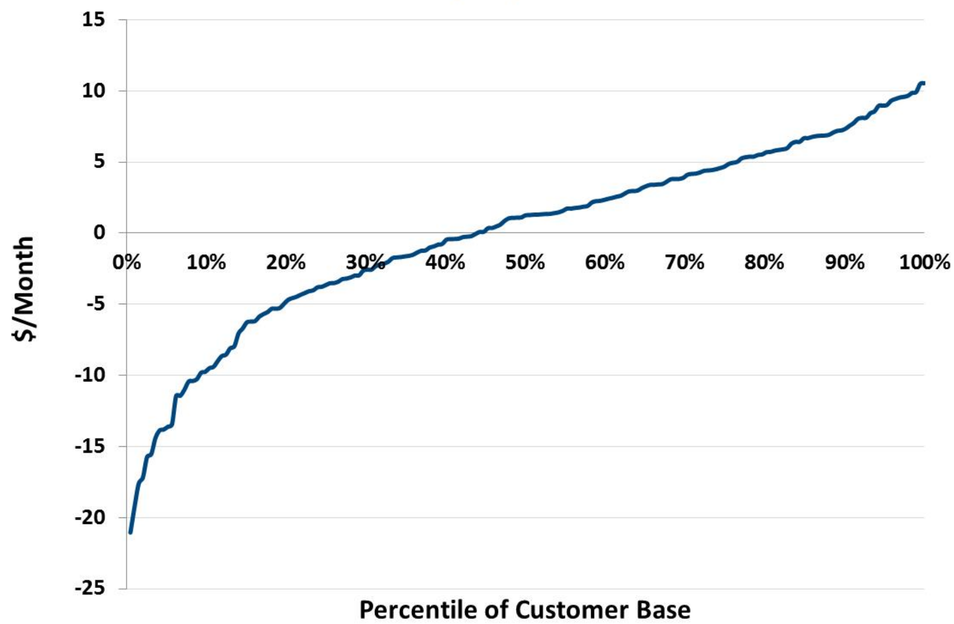
[13] The Residential Standard Service rate in 2015 is a two-part rate with a $15/month fixed charge.

slight differences between the load research sample and the class load profile.

Q. WHAT WILL BE THE IMPACT OF THE PROPOSED RATE CHANGES ON CUSTOMER BILLS?

A. If <u>all</u> customers were to remain on the current two-part tariff, many would experience bill changes over the multi-year rate transition. As the fixed charge increases from $15/month to $27/month over four years, and the volumetric charge decreases in an offsetting manner to ensure revenue neutrality, some customers would experience bill decreases and some would experience bill increases. A summary of the resulting change in the average monthly bill for the customers in Westar's load research sample is shown in Figure 3.

Figure 3: Distribution of Bill Impacts if All Customers Remain on Current Rate (2019)

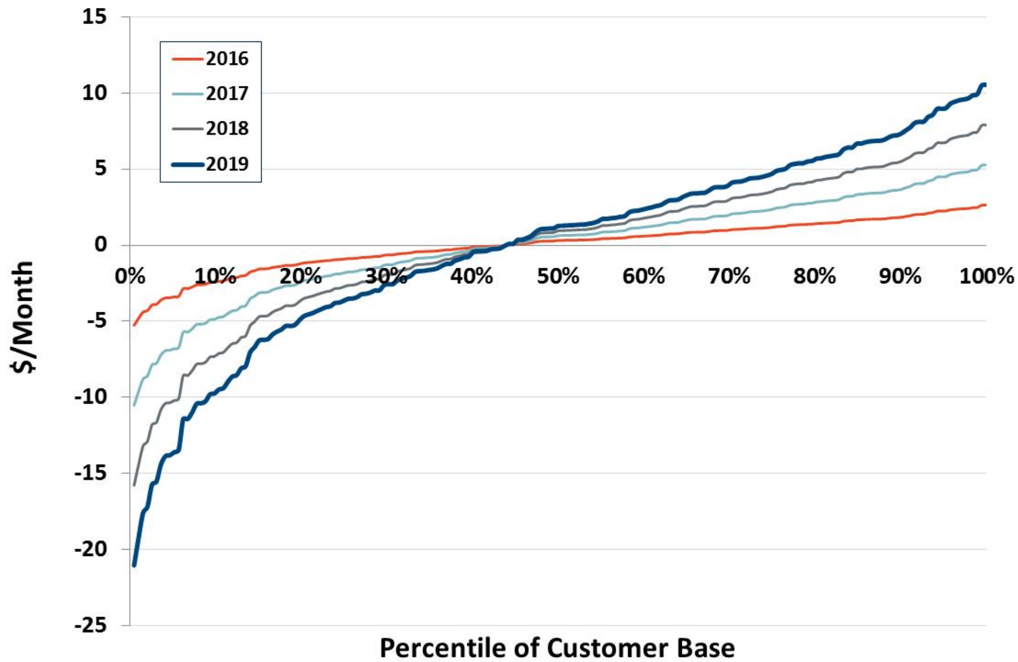


At the extremes, some customers could experience a bill decrease (i.e., savings) of around $20/month or a bill increase of around $10/month. Most customers would experience bill changes that are significantly less than this. Roughly 57 percent of customers would experience a bill decrease or increase of less than $5/month.

Q. WILL CUSTOMERS EXPERIENCE THESE BILL IMPACTS INSTANTANEOUSLY?

A. No, customers will experience the transition to the new rates gradually. Westar has proposed to increase the fixed charge in $3 increments from $15/month in 2015 to $27/month in 2019. Therefore, the bill impacts summarized in Figure 3 above would be reached gradually over several years, rather than instantaneously. Figure 4 below illustrates the annual progression of bill impacts from 2015 to 2019.

Figure 4: Annual Bill Impacts if All Customers Remain on Current Rate



Q. DO YOU EXPECT CUSTOMERS TO SWITCH AWAY FROM THE STANDARD RATE TO ONE OF THE TWO NEW RATE OPTIONS?

A. It is likely that some customers will choose to switch away from the standard rate and enroll in one of the new rate options. Customers are most likely to do so if they see an opportunity to reduce their bill by enrolling in a new rate, or if they wish to smooth out the seasonal variation in their bills. The magnitude of the bill savings opportunity is a key factor that will determine their likelihood of adopting the new rate. It is also possible that customers will be attracted to other features of the new rates that do not directly lead to bill reductions.

At the same time, there are also factors that will limit customer interest in switching to the new rates. Customers have limited resources and time available to study and react to their electricity bill.

A recent study found that customers spend six minutes per year thinking about their energy bills.[14] This may be because electricity represents a relatively small portion of customers' incomes, as Westar witness Mr. Ruelle notes in his testimony. Other customers are risk averse and have a fear of the unknown. Even in cases where customers have a clear opportunity to reduce their bill by switching to one of the two alternative rate options, they may not choose to do so. Research that I conducted with colleagues shows that most customers are likely to remain on the default rate when presented with alternatives even though they may appreciate the choice being offered to them.[15]

Q. HAVE YOU ANALYZED THE SWITCHING BEHAVIOR OF CUSTOMERS THAT WILL OCCUR WHEN THE NEW RATES ARE OFFERED?

A. Yes. I have simulated the impacts of rate switching under two different modeling frameworks. The first approach, which is only provided for illustrative purposes, assumes that customers have perfect access to information and know exactly what their bill would be under each rate. I refer to this as the "Perfect Choice" modeling approach. The second approach takes into account realistic switching behavior and accounts for uncertainty and the range of

[14] https://opower.com/uploads/library/file/23/Privacy_Principles_1.18.12.pdf

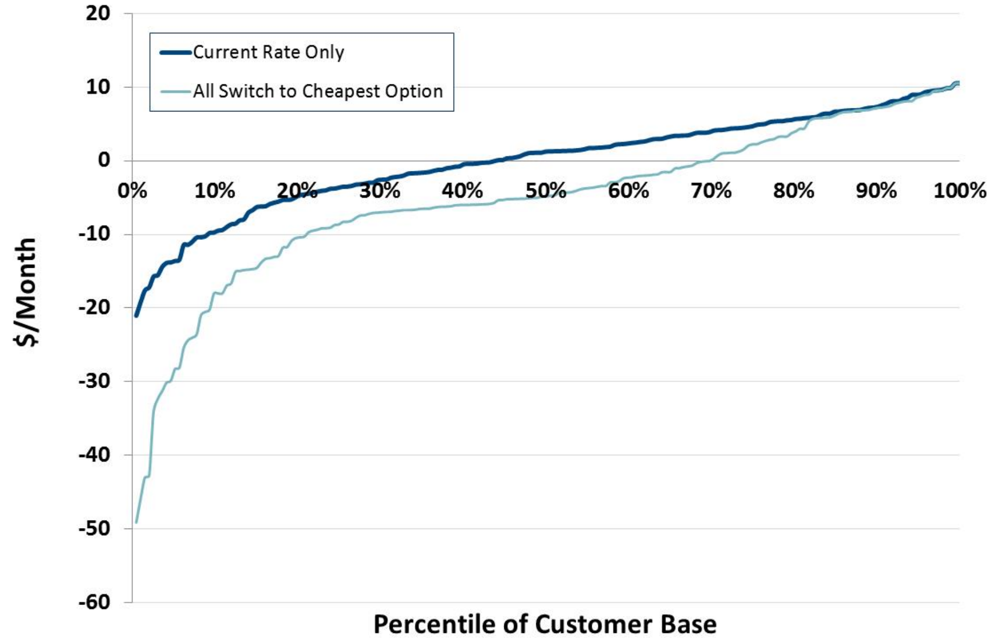
[15] Ahmad Faruqui, Ryan Hledik, and Neil Lessem, "Smart by Default," *Public Utilities Fortnightly*, August 2014.

preferences that are likely to be demonstrated by customers during the actual rollout. I refer to this as the "Likely Choice" approach.

Q. HOW MUCH SWITCHING WOULD TAKE PLACE UNDER THE HYPOTHETICAL "PERFECT CHOICE" APPROACH?

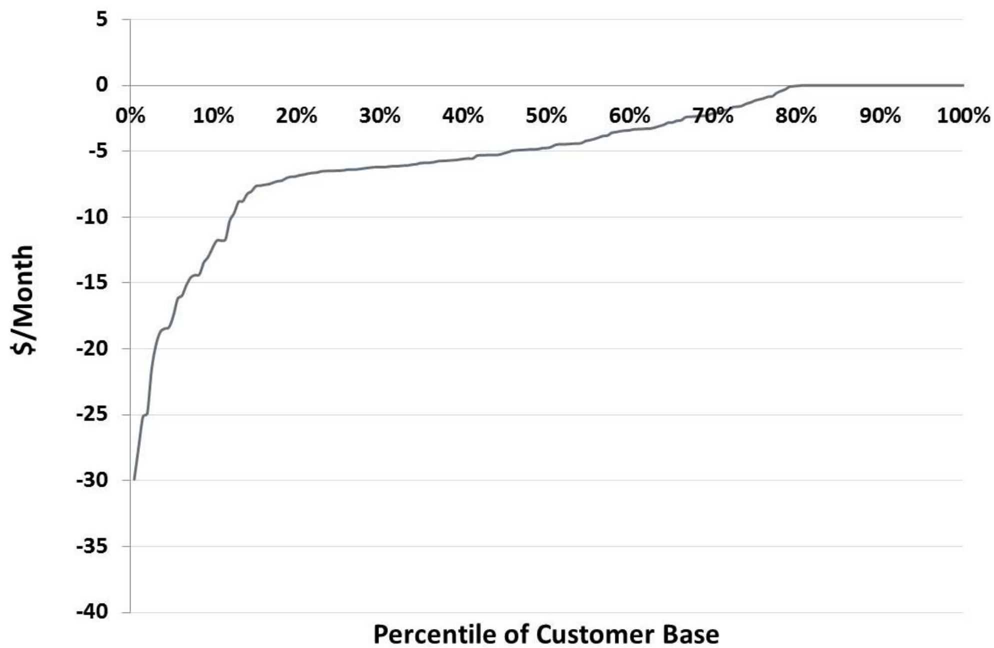
A. If <u>all</u> customers enroll in the rate that minimizes their bill, roughly 20 percent would stay on the Residential Standard Service rate, 36 percent would switch to the Residential Demand Plan rate, and 44 percent would switch to the Residential Stability Plan rate. Under this scenario, roughly 70 percent of Westar's customers would experience a bill decrease as part of the multi-year rate transition (compared to about 44 percent if no customers switched, as illustrated previously in Figure 3). Figure 5 illustrates how the distribution of customer bill impacts changes after accounting for switching under the "Perfect Choice" modeling approach.

Figure 5: Bill Impacts in 2019 Before and After Switching ("Perfect Choice" Approach)



On average, those customers who switch would save roughly 4.5 percent ($6.51/month) on their bills as a result of switching, equating to a 3.8 percent reduction in total residential revenue for Westar. Figure 6 illustrates the distribution of bill savings for those customers who switch. At the extreme, customers in the load research sample could save up to around $30/month by switching to one of the new rate options.

Figure 6: Bill Savings Due to Rate Switching ("Perfect Choice" Approach)



It is possible that customers would only switch to a new rate if it provides them with some minimum amount of bill savings. For example, customers might not be interested in switching to a new rate if it only saves them a few pennies, but that same rate could be considered an attractive opportunity for a different set of customers who, due to having different consumption patterns, could reduce their bills by five or ten percent by enrolling. Table 2 below illustrates the percentage of customers who would switch at various bill savings thresholds, with the savings thresholds expressed as both a percentage of the total bill and in dollars per month. It shows, for instance, that 28 percent of customers would have the opportunity to save at least five percent by switching to one of the alternative rates, and 12 percent of customers could save at least $10/month by switching.

Table 2: Customer Switching at Various Bill Savings Thresholds Under Perfect Choice Approach (2019)

Savings Threshold as % of Bill:	***0.0%***	***2.5%***	***5.0%***	***7.5%***	***10.0%***	***12.5%***	***15.0%***
Percent Switched	80.2%	62.0%	28.1%	7.3%	1.6%	0.0%	0.0%
Residential Revenue Change	-3.8%	-3.6%	-2.2%	-0.9%	-0.2%	0.0%	0.0%
Avg Savings of Switcher (%)	-4.5%	-5.2%	-6.9%	-9.0%	-11.1%	-	-
Avg Savings of Switcher ($/Month)	-$6.51	-$7.86	-$10.91	-$17.62	-$16.83	-	-
Savings Threshold in $/Month:	***$0.00***	***$5.00***	***$10.00***	***$15.00***	***$20.00***	***$25.00***	***$30.00***
Percent Switched	80.2%	45.3%	12.0%	6.8%	2.6%	1.6%	0.0%
Residential Revenue Change	-3.8%	-3.1%	-1.5%	-1.0%	-0.5%	-0.3%	0.0%
Avg Savings of Switcher (%)	-4.5%	-5.6%	-7.5%	-8.5%	-8.8%	-9.2%	-
Avg Savings of Switcher ($/Month)	-$6.51	-$9.28	-$17.25	-$20.69	-$25.79	-$27.50	-

This modeling approach is useful in that it represents a “bookend” on the level of switching that would take place. However, as an extreme case, it is unrealistic. As I discussed previously, customers have limited time, interest and resources available to dedicate to minimizing their electricity bill. There is uncertainty about their future consumption patterns and how that will affect their bills under the different rate options. Some customers may end up choosing a rate that increases their bill.[16] These factors should be taken into account when modeling customer switching behavior, and I have done that in the “Likely Choice” approach.

[16] For example, I analyzed the bills of 7,128 customers enrolled in Westar’s voluntary Peak Management rate with 12 months of consumption and demand data from October 1, 2013 to September 30, 2014. Approximately 37% of these customers would have lower bills if they instead chose to enroll in Westar’s standard rate option.

Q. HOW MUCH SWITCHING IS LIKELY TO TAKE PLACE UNDER THE "LIKELY CHOICE" APPROACH?

A. To implement the "Likely Choice" approach, I relied on the *Rate Choice Model,* which I developed with a team of consultants at Brattle. The *Rate Choice Model* is a "discrete choice model" that captures likely customer switching rates by accounting for the observation that some customers will switch to a rate that increases their bill, and some other customers will choose to remain on the current rate even when one of the two alternative new options could lower their bill.[17] By varying the parameters of the model, I am able to capture a reasonable range of assumptions about the customers' likelihood of switching away from the standard rate and their ability to accurately choose the rate that minimizes their bills. A detailed description of the model is included in Appendix E.

The actual switching behavior of Westar's customers will depend on a number of factors, such as how effectively the new rates are marketed, how engaged the customers are in energy management, how well they understand both their bill and the new rate options, and their level of risk aversion, among other factors. Given uncertainty around these factors, I analyzed two scenarios of switching behavior under the Likely Choice approach.

[17] Discrete choice models are often called logit models. Much of the original work on these models was performed by Daniel McFadden, a principal with Brattle, who was a professor at UC Berkeley at that time.

Q. WHAT WAS THE FIRST SCENARIO YOU ANALYZED?

A. The first scenario is calibrated to observed enrollment in Westar's Peak Management rate, which was offered to customers in the Westar North rate area beginning in 1981.[18] At its peak enrollment in 1998, approximately 15,600 customers were enrolled in the rate, representing roughly five percent of Westar's total residential customer base at that time.[19] The example of the Peak Management rate may provide a conservative estimate of the switching that would be expected under Westar's proposals in this case.

Q. WHY DO YOU BELIEVE THAT WESTAR'S EXPERIENCE WITH CUSTOMER ENROLLMENT IN THE PEAK MANAGEMENT RATE MAY BE A CONSERVATIVE ESTIMATE OF THE SWITCHING THAT WILL OCCUR UNDER THE NEW RATE OPTIONS?

A. I believe that to be a conservative case because the circumstances in which the Peak Management rate was offered are different from today's conditions. First, the Peak Management rate was offered only to customers in the Westar North rate area. Second, my understanding is that Westar only marketed the rate to customers

[18] The Peak Management Rate was implemented by The Kansas Power and Light Company (Westar North) prior to the merger with Kansas Gas and Electric Company (Westar South) that created Westar Energy. The Peak Management rate was never offered in the Westar South after the merger.

[19] The rate was closed to new enrollment in January 2006 when Westar consolidated the rates for its North and South rate areas, and participation has gradually tapered off since then as a result.

with electric heat, such as baseboard or heat pumps. My understanding from conversations with Westar is that the new rate is intended to be marketed to a larger customer base. Third, there is evidence that today's consumers are more interested in managing their energy bills, as demonstrated by the success of home energy reports and adoption of new energy management products like the Nest thermostat. To the extent that the Residential Demand Plan rate is seen by customers as an opportunity to manage their peak demands and reduce their energy costs by shifting their usage away from the peak period, they are more likely to enroll in that rate.

Calibrating the *Rate Choice Model* to roughly a five percent switching rate, I estimate that the bills of those customers who switch would decrease on average by between 1.7 and 4.1 percent ($2.44/month to $6.60/month) relative to a scenario in which all customers remain on the current rate. This equates to a reduction of between 0.1 and 0.3 percent in Westar's total residential revenue. The range of impacts accounts for a range of realistic assumptions regarding the ability of switchers to accurately choose the rate that minimizes their bill.

Q. WHAT WAS THE SECOND SCENARIO YOU ANALYZED?

A. The second scenario is based on the highest switching rates observed at other utilities around the U.S. A combination of market research studies and utility rate deployments have demonstrated that it is possible to achieve a 20 percent switching rate through heavy marketing and customer education initiatives.[20] For example, Oklahoma Gas & Electric has rolled out a new technology-enabled dynamic pricing rate to its customers, with a target of 20 percent enrollment over the first three years of the rollout.[21] Calibrating my model to a 20 percent switching rate results in average bill savings that range from 1.6 percent to 3.6 percent ($2.29/month to $5.56/month). These savings pertain to customers who switch to the new rate and are measured relative to a scenario in which all customers remain on the current rate. This translates into a loss of revenue for Westar that ranges from 0.3 to 0.8 percent. The results of both scenarios are summarized in Table 3.

Table 3: Customer Switching Under the Likely Choice Approach (2019)

	Residential Customers Switching to New Rate %	Average Bill Savings of Customer Who Switches %	Average Bill Savings of Customer Who Switches $/month	Change in Westar Annual Residential Revenue %
Scenario 1: Calibrated to historical Peak Management switching behavior	5% to 6%	1.7% to 4.1%	$2.44 to $6.60	-0.1% to -0.3%
Scenario 2: Calibrated to high switching rate observed at some other utilities	17% to 20%	1.6% to 3.6%	$2.29 to $5.56	-0.3% to -0.8%

Note: Range of impacts reflects a range of reasonable assumptions about switchers' ability to choose the rate that minimizes their bill.

[20] Ahmad Faruqui, Ryan Hledik, and Neil Lessem, "Smart by Default," *Public Utilities Fortnightly*, August 2014.

[21] The rate is a variable peak pricing (VPP) rate, which charges higher prices during peak hours on a limited number of days during the summer, and offers a discounted price during all other hours. OGE was targeting 120,000 participants by the end of 2014. http://tdworld.com/demand-response/oge-smarthours-program-target-sustainability-and-growth

Q. WHAT DO YOU CONCLUDE ABOUT LIKELY CUSTOMER SWITCHING BEHAVIOR WHEN THE NEW RATES ARE OFFERED?

A. Some customers are likely to switch to the two new rate options. The extent to which the customers switch will depend partly on how heavily they are marketed by Westar through customer outreach activities and partly on how inherently engaged Westar's customers are in managing their electricity bills. Realistic switching rates over the five year transition period could range from being small (i.e., a few customers) to as much as 20 percent of the residential customer base. On average, the option to switch could lead to bill savings of up to around 4.1 percent ($6.60/month) for those customers who switch, with some customers saving more or less than this. These bill decreases due to rate switching will equate to revenue loss for Westar.

Q. WHAT ARE THE IMPLICATIONS OF YOUR ANALYSIS OF CUSTOMER BILLS?

A. Any revenue neutral change to a rate's design will cause some customers to experience bill increases and others to experience bill decreases. With the transition to a rate that more accurately reflects costs, as Westar has proposed, these bill changes reflect the removal of a subsidy that existed in the old rate. In other words, the bill changes show that the new rate is correcting an inequity in the old rate.

In recognition of the fact that customer bills will be changing, it is important to have a transition strategy to avoid large, unexpected bill increases for some customers. Three elements of Westar's rate proposal facilitate this transition. First, the transition is gradual. It ramps up the fixed monthly charge from $12/month to $27/month over a five year period. Doing so ensures that customers will be eased into the new rate structure, providing them ample time to explore bill management options. Second, the proposal includes rate choice. By providing customers with a choice of rates, they will have the option to reduce their bills through rate switching, as I discuss above. Third, the new rate options are voluntary for non-DG customers. (DG customers would have the choice of two options.) By rolling out the new rates on a voluntary basis, Westar does not force customers on to a rate that may not be their preferred option.

It will be important to closely monitor customer switching behavior once the new rates are rolled out. My simulations are based on the best available data and modeling techniques of which I am aware, but these results should be refined with new analysis once there is real experience with the new rates after they are rolled out in in Westar's service territory. Westar witness Mr. Wolfram sponsors an approach to track and defer any revenue over-recovery or shortfall resulting from rate switching and to credit or recover the deferred amount in a future rate case.

VII. CONCLUSIONS

Q. HOW WOULD YOU CONCLUDE YOUR TESTIMONY?

A. To ensure that the principle of cost-causation is reflected in Westar's rates for residential customers, and to eliminate inter-customer inequities, the company is proposing to offer three rate design choices to all residential customers who do not have their own generation and to offer two rate design choices to those who have generation. I believe these new rate designs are consistent with the principles of rate design and should be offered to Westar's customers. As with any rate change, some customers will see higher bills and some will see lower bills. I have quantified the bill impacts. To manage the adverse effect of the rate changes on some customers, Westar is proposing to roll out the proposed new rates consistent with the principle of gradualism and to provide protection for customers and Westar in the event that switching is larger or smaller than estimated.

Q. DOES THAT CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

Appendix A: Ahmad Faruqui Resume

Dr. Ahmad Faruqui leads a consulting practice focused on understanding and managing the way customers use energy. During his career, he has consulted with more than 125 utilities, commissions, government agencies, system operators, merchant generators, equipment manufacturers, technology developers, and energy service companies. His 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, his consulting practice is creating alternative rate designs, testing their impact on customer bills, and sponsoring testimony to have them implemented. It is 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. It has 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.** The practice helps 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. It is 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, the practice is studying the impact of dynamic pricing. It has completed similar studies for a utility in the Asia-Pacific region and a regulatory body in the Middle East. It also conducts 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.** The practice is studying the potential role of combined heat and power in enhancing energy efficiency in large commercial and industrial facilities. It is 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**. The practice analyzes 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 70 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 dynamic 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

California

Prepared testimony before the Public Utilities Commission of the State of California on behalf of Pacific Gas and Electric Company on rate relief, Docket No. A.10-03-014, summer 2010.

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.

Testimony on behalf of the Pacific Gas & Electric Company, in its application for Automated Metering Infrastructure with the California Public Utilities Commission. Docket No. 05-06-028, 2006.

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

Testimony before the Department of Public Utility Control, on behalf of the Connecticut Light and Power Company, in its application to implement Time-of-Use , Interruptible Load Response, and Seasonal Rates- Submittal of Metering and Rate Pilot Results- Compliance Order No. 4, Docket no. 05-10-03RE01, 2007.

District of Columbia

Direct testimony before the Public Service Commission of the District of Columbia on behalf of Potomac Electric Power Company in the matter of the Application of Potomac Electric Power Company for Authorization to Establish a Demand Side Management Surcharge and an Advance Metering Infrastructure Surcharge and to Establish a DSM Collaborative and an AMI Advisory Group, case no. 1056, May 2009.

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.

Testimony before the State of Illinois – Illinois Commerce Commission on behalf of Commonwealth Edison Company regarding the evaluation of experimental residential real-time pricing program, 11-0546, April 2012.

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.

Maryland

Direct testimony before the Public Service Commission of Maryland, on behalf of Potomac Electric Power Company and Delmarva Power and Light Company, on the deployment of Advanced Meter Infrastructure. Case no. 9207, September 2009.

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

Rebuttal testimony before the Minnesota Public Utilities Commission State of Minnesota on behalf of Northern States Power Company, doing business as Xcel Energy, in the matter of the Application of Northern States Power Company for Authority to Increase Rates for Electric Service in Minnesota, Docket No. E002/GR-12-961, March 25, 2013.

Direct testimony before the Minnesota Public Utilities Commission State of Minnesota on behalf of Northern States Power Company, doing business as Xcel Energy, in the matter of the Application of Northern States Power Company for Authority to Increase Rates for Electric Service in Minnesota, Docket No. E002/GR-12-961, November 2, 2012.

Pennsylvania

Direct testimony before the Pennsylvania Public Utility Commission, on behalf of PECO on the Methodology Used to Derive Dynamic Pricing Rate Designs, Case no. M-2009-2123944, October 28, 2010.

REGULATORY APPEARANCES

Arkansas

Presented before the Arkansas Public Service Commission, “The Emergence of Dynamic Pricing” at the workshop on the Smart Grid, Demand Response, and Automated Metering Infrastructure, Little Rock, Arkansas, September 30, 2009.

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

"Making the Most of the No Load Growth Business Environment," with Dian Grueneich. *Distributed Generation and Its Implications for the Utility Industry*. Ed. Fereidoon P. Sioshansi. Academic Press, 2014. 303-320.

"*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.

"Will Energy Efficiency make a Difference," with Fereidoon P. Sioshansi and Gregory Wikler. *Energy Efficiency: Towards the end of demand growth*. Ed. Fereidoon P. Sioshansi. Academic Press, 2013. 3-50.

"The Ethics of Dynamic Pricing." *Smart Grid: Integrating Renewable, Distributed & Efficient Energy*. Ed. Fereidoon P. Sioshansi. Academic Press, 2012. 61-83.

Electricity Pricing in Transition. Co-editor with Kelly Eakin. Kluwer Academic Publishing, 2002.

Pricing in Competitive Electricity Markets. Co-editor with Kelly Eakin. Kluwer Academic Publishing, 2000.

Customer Choice: Finding Value in Retail Electricity Markets. Co-editor with J. Robert Malko. Public Utilities Inc. Vienna. Virginia: 1999.

The Changing Structure of American Industry and Energy Use Patterns. Co-editor with John Broehl. Battelle Press, 1987.

Customer Response to Time of Use Rates: Topic Paper I, with Dennis Aigner and Robert T. Howard, Electric Utility Rate Design Study, EPRI, 1981.

Technical Reports

Quantifying the Amount and Economic Impacts of Missing Energy Efficiency in PJM's Load Forecast, with Sanem Sergici and Kathleen Spees, prepared for The Sustainable FERC Project, September 2014.

Structure of Electricity Distribution Network Tariffs: Recovery of Residual Costs, with Toby Brown, prepared for the Australian Energy Market Commission, August 2014.

Impact Evaluation of Ontario's Time-of-Use Rates: First Year Analysis, with Sanem Sergici, Neil Lessem, Dean Mountain, Frank Denton, Byron Spencer, and Chris King, prepared for Ontario Power Authority, November 2013.

Time-Varying and Dynamic Rate Design, with Ryan Hledik and Jennifer Palmer, prepared for RAP, July 2012. http://www.raponline.org/document/download/id/5131

The Costs and Benefits of Smart Meters for Residential Customers, with Adam Cooper, Doug Mitarotonda, Judith Schwartz, and Lisa Wood, prepared for Institute for Electric Efficiency, July 2011. http://www.smartgridnews.com/artman/uploads/1/IEE_Benefits_of_Smart_Meters_Final.pdf

Measurement and Verification Principles for Behavior-Based Efficiency Programs, with Sanem Sergici, prepared for Opower, May 2011. http://opower.com/uploads/library/file/10/brattle_mv_principles.pdf

Methodological Approach for Estimating the Benefits and Costs of Smart Grid Demonstration Projects. With R. Lee, S. Bossart, R. Hledik, C. Lamontagne, B. Renz, F. Small, D. Violette, and D. Walls. Pre-publication draft, prepared for the U. S. Department of Energy, Office of Electricity Delivery and Energy Reliability, the National Energy Technology Laboratory, and the Electric Power Research Institute. Oak Ridge, TN: Oak Ridge National Laboratory, November 28, 2009.

Moving Toward Utility-Scale Deployment of Dynamic Pricing in Mass Markets. With Sanem Sergici and Lisa Wood. Institute for Electric Efficiency, June 2009.

Demand-Side Bidding in Wholesale Electricity Markets. With Robert Earle. Australian Energy Market Commission, 2008. http://www.aemc.gov.au/electricity.php?r=20071025.174223

Assessment of Achievable Potential for Energy Efficiency and Demand Response in the U.S. (2010-2030). With Ingrid Rohmund, Greg Wikler, Omar Siddiqui, and Rick Tempchin. American Council for an Energy-Efficient Economy, 2008**.**

Quantifying the Benefits of Dynamic Pricing in the Mass Market. With Lisa Wood. Edison Electric Institute, January 2008.

California Energy Commission. *2007 Integrated Energy Policy Report,* CEC-100-2007-008-CMF.

Applications of Dynamic Pricing in Developing and Emerging Economies. Prepared for The World Bank, Washington, DC. May 2005.

Preventing Electrical Shocks: What Ontario—And Other Provinces—Should Learn About Smart Metering. With Stephen S. George. C. D. Howe Institute Commentary, No. 210, April 2005.

Primer on Demand-Side Management. Prepared for The World Bank, Washington, DC. March 21, 2005.

Electricity Pricing: Lessons from the Front. With Dan Violette. White Paper based on the May 2003 AESP/EPRI Pricing Conference, Chicago, Illinois, EPRI Technical Update 1002223, December 2003.

Electric Technologies for Gas Compression. Electric Power Research Institute, 1997.

Electrotechnologies for Multifamily Housing. With Omar Siddiqui. EPRI TR-106442, Volumes 1 and 2. Electric Power Research Institute, September 1996.

Opportunities for Energy Efficiency in the Texas Industrial Sector. Texas Sustainable Energy Development Council. With J. W. Zarnikau et al. June 1995.

Principles and Practice of Demand-Side Management. With John H. Chamberlin. EPRI TR-102556. Palo Alto: Electric Power Research Institute, August 1993.

EPRI Urban Initiative: *1992 Workshop Proceedings (Part I)*. The EPRI Community Initiative. With G.A. Wikler and R.H. Manson. TR-102394. Palo Alto: Electric Power Research Institute, May 1993.

Practical Applications of Forecasting Under Uncertainty. With K.P. Seiden and C.A. Sabo.TR-102394. Palo Alto: Electric Power Research Institute, December 1992.

Improving the Marketing Infrastructure of Efficient Technologies: A Case Study Approach. With S.S. Shaffer. EPRI TR- I 0 1 454. Palo Alto: Electric Power Research Institute, December 1992.

Customer Response to Rate Options. With J. H. Chamberlin, S.S. Shaffer, K.P. Seiden, and S.A. Blanc. CU-7131. Palo Alto: Electric Power Research Institute (EPRI), January 1991.

Articles and Chapters

"Smart By Default," with Ryan Hledik and Neil Lessem, *Public Utilities Fortnightly*, August 2014. http://www.fortnightly.com/fortnightly/2014/08/smart-default?page=0%2C0&authkey=e5b59c3e26805e2c6b9e469cb9c1855a9b0f18c67bbe7d8d4ca

08a8abd39c54d

"Quantile Regression for Peak Demand Forecasting," with Charlie Gibbons, SSRN, July 31, 2014.
http://papers.ssrn.com/sol3/papers.cfm?abstract_id=2485657

"Study Ontario for TOU Lessons," *Intelligent Utility*, April 1, 2014.
http://www.intelligentutility.com/article/14/04/study-ontario-tou-lessons?quicktabs_11=1&quicktabs_6=2

"Impact Measurement of Tariff Changes When Experimentation is Not an Option – a Case Study of Ontario, Canada," with Sanem Sergici, Neil Lessem, and Dean Mountain, SSRN, March 2014.
http://ssrn.com/abstract=2411832

"Dynamic Pricing in a Moderate Climate: The Evidence from Connecticut," with Sanem Sergici and Lamine Akaba, *Energy Journal*, 35:1, pp. 137-160, January 2014.

"Charting the DSM Sales Slump," with Eric Schultz, *Spark*, September 2013.
http://spark.fortnightly.com/fortnightly/charting-dsm-sales-slump

"Arcturus: International Evidence on Dynamic Pricing," with Sanem Sergici, *The Electricity Journal*, 26:7, August/September 2013, pp. 55-65.
http://www.sciencedirect.com/science/article/pii/S1040619013001656

"Dynamic Pricing of Electricity for Residential Customers: The Evidence from Michigan," with Sanem Sergici and Lamine Akaba, *Energy Efficiency*, 6:3, August 2013, pp. 571–584.

"Benchmarking your Rate Case," with Ryan Hledik, *Public Utility Fortnightly*, July 2013.
http://www.fortnightly.com/fortnightly/2013/07/benchmarking-your-rate-case
"Surviving Sub-One-Percent Growth," *Electricity Policy*, June 2013.
http://www.electricitypolicy.com/articles/5677-surviving-sub-one-percent-growth

"Demand Growth and the New Normal," with Eric Shultz, *Public Utility Fortnightly*, December 2012.
http://www.fortnightly.com/fortnightly/2012/12/demand-growth-and-new-normal?page=0%2C1&authkey=4a6cf0a67411ee5e7c2aee5da4616b72fde10e3fbe215164cd4e5dbd8e9d0c98

"Energy Efficiency and Demand Response in 2020 – A Survey of Expert

Opinion," with Doug Mitarotonda, March 2012. Available at SSRN: http://ssrn.com/abstract=2029150

"Dynamic Pricing for Residential and Small C&I Customers," presented at the Ohio Public Utilities Commission Technical Workshop, March 28, 2012. http://www.brattle.com/_documents/UploadLibrary/Upload1026.pdf

"The Discovery of Price Responsiveness – A Survey of Experiments Involving Dynamic Pricing of Electricity," with Jennifer Palmer, *Energy Delta Institute*, Vol.4, No. 1, April 2012. http://www.energydelta.org/mainmenu/edi-intelligence-2/our-services/quarterly-2/edi-quarterly-vol-4-issue-1

"Green Ovations: Innovations in Green Technologies," with Pritesh Gandhi, *Electric Energy T&D Magazine*, January-February 2012. http://www.electricenergyonline.com/?page=show_article&mag=76&article=618

"Dynamic Pricing of Electricity and its Discontents" with Jennifer Palmer, *Regulation*, Volume 34, Number 3, Fall 2011, pp. 16-22. http://www.cato.org/pubs/regulation/regv34n3/regv34n3-5.pdf

"Smart Pricing, Smart Charging," with Ryan Hledik, Armando Levy, and Alan Madian, *Public Utility Fortnightly*, Volume 149, Number 10, October 2011. http://www.fortnightly.com/archive/puf_archive_1011.cfm

"The Energy Efficiency Imperative" with Ryan Hledik, *Middle East Economic Survey*, Vol LIV: No. 38, September 19, 2011.

"Are LDCs and customers ready for dynamic prices?" with Jürgen Weiss, *Fortnightly's Spark*, August 25, 2011. http://spark.fortnightly.com/sitepages/pid58.php?ltemplate=intro_archive&pageId=58&lcommtypeid=6&item_id=33

"Dynamic pricing of electricity in the mid-Atlantic region: econometric results from the Baltimore gas and electric company experiment," with Sanem Sergici, *Journal of Regulatory Economics*, 40:1, August 2011, pp. 82-109.

"Better Data, New Conclusions," with Lisa Wood, *Public Utilities Fortnightly*, March 2011, pp. 47-48. http://www.fortnightly.com/archive/puf_archive_0311.cfm

"Residential Dynamic Pricing and 'Energy Stamps,'" *Regulation*, Volume 33, No. 4, Winter 2010-2011, pp. 4-5. http://www.cato.org/pubs/regulation/regv33n4/v33n4.html

"Dynamic Pricing and Low-Income Customers: Correcting misconceptions about load-management programs," with Lisa Wood, *Public Utilities Fortnightly*, November 2010, pp. 60-64. http://www.fortnightly.com/archive/puf_archive_1110.cfm

"The Untold Story: A Survey of C&I Dynamic Pricing Pilot Studies" with Jennifer Palmer and Sanem Sergici, *Metering International*, ISSN: 1025-8248, Issue: 3, 2010, p.104.
"Household response to dynamic pricing of electricity–a survey of 15 experiments," with Sanem Sergici, *Journal of Regulatory Economics* (2010), 38:193-225

"Unlocking the €53 billion savings from smart meters in the EU: How increasing the adoption of dynamic tariffs could make or break the EU's smart grid investment," with Dan Harris and Ryan Hledik, *Energy Policy*, Volume 38, Issue 10, October 2010, pp. 6222-6231. http://www.sciencedirect.com/science/article/pii/S0301421510004738

"Fostering economic demand response in the Midwest ISO," with Attila Hajos, Ryan Hledik, and Sam Newell, *Energy*, Volume 35, Issue 4, Special Demand Response Issue, April 2010, pp. 1544-1552. http://www.sciencedirect.com/science/article/pii/S0360544209004009

"The impact of informational feedback on energy consumption – A survey of the experimental evidence," with Sanem Sergici and Ahmed Sharif, *Energy*, Volume 35, Issue 4, Special Demand Response Issue, April 2010, pp. 1598-1608. http://www.sciencedirect.com/science/article/pii/S0360544209003387

"Dynamic tariffs are vital for smart meter success," with Dan Harris, *Utility Week*, March 10, 2010. http://www.utilityweek.co.uk/news/news_story.asp?id=123888&title=Dynamic+tariffs+are+vital+for+smart+meter+success

"Rethinking Prices," with Ryan Hledik and Sanem Sergici, *Public Utilities Fortnightly*, January 2010, pp. 31-39. http://www.fortnightly.com/uploads/01012010_RethinkingPrices.pdf

"Piloting the Smart Grid," with Ryan Hledik and Sanem Sergici, *The Electricity Journal*, Volume 22, Issue 7, August/September 2009, pp. 55-69. http://www.sciencedirect.com/science/article/pii/S1040619009001663

"Smart Grid Strategy: Quantifying Benefits," with Peter Fox-Penner and Ryan Hledik, *Public Utilities Fortnightly*, July 2009, pp. 32-37. http://www.fortnightly.com/pubs/07012009_QuantifyingBenefits.pdf

"The Power of Dynamic Pricing," with Ryan Hledik and John Tsoukalis, *The Electricity Journal*, April 2009, pp. 42-56. http://www.sciencedirect.com/science/article/pii/S1040619009000414

"Transition to Dynamic Pricing," with Ryan Hledik, *Public Utilities Fortnightly*, March 2009, pp. 26-33. http://www.fortnightly.com/display_pdf.cfm?id=03012009_DynamicPricing.pdf

"Ethanol 2.0," with Robert Earle, *Regulation*, Winter 2009. http://www.cato.org/pubs/regulation/regv31n4/v31n4-noted.pdf

"Inclining Toward Efficiency," *Public Utilities Fortnightly*, August 2008, pp. 22-27. http://www.fortnightly.com/exclusive.cfm?o_id=94

"California: Mandating Demand Response," with Jackalyne Pfannenstiel, *Public Utilities Fortnightly*, January 2008, pp. 48-53. http://www.fortnightly.com/display_pdf.cfm?id=01012008_MandatingDemandResponse.pdf

"Avoiding Load Shedding by Smart Metering and Pricing," with Robert Earle, *Metering International*, Issue 1 2008, pp. 76-77.

"The Power of 5 Percent," with Ryan Hledik, Sam Newell, and Hannes Pfeifenberger, *The Electricity Journal,* October 2007, pp. 68-77. http://www.sciencedirect.com/science/article/pii/S1040619007000991

"Pricing Programs: Time-of-Use and Real Time," *Encyclopedia of Energy Engineering and Technology,* September 2007, pp. 1175-1183. http://www.drsgcoalition.org/resources/other/Pricing_Programs_TOU_and_RTP.pdf

"Breaking Out of the Bubble: Using demand response to mitigate rate shocks," *Public Utilities Fortnightly*, March 2007, pp. 46-48 and pp. 50-51. http://brattlegroup.com/_documents/uploadlibrary/articlereport2438.pdf

"From Smart Metering to Smart Pricing," *Metering International,* Issue 1, 2007. http://www.brattle.com/_documents/UploadLibrary/ArticleReport2439.pdf

"Demand Response and the Role of Regional Transmission Operators," with Robert Earle, *2006 Demand Response Application Service*, Electric Power Research Institute, 2006.

"2050: A Pricing Odyssey," *The Electricity Journal,* October, 2006. http://www.puc.nh.gov/Electric/06061/epact%20articles/EJ%202050%20%20A%20Pricing%20Odyssey.pdf

"Demand Response and Advanced Metering," Regulation, Spring 2006. 29:1 24-27. http://www.cato.org/pubs/regulation/regv29n1/v29n1-3.pdf

"Reforming electricity pricing in the Middle East," with Robert Earle and Anees Azzouni, *Middle East Economic Survey (MEES)*, December 5, 2005.

"Controlling the thirst for demand," with Robert Earle and Anees Azzouni, *Middle East Economic Digest (MEED),* December 2, 2005. http://www.crai.com/uploadedFiles/RELATING_MATERIALS/Publications/files/Controlling%20the%20Thirst%20for%20Demand.pdf

"California pricing experiment yields new insights on customer behavior," with Stephen S. George, *Electric Light & Power*, May/June 2005. http://www.elp.com/index/display/article-display/229131/articles/electric-light-power/volume-83/issue-3/departments/news/california-pricing-experiment-yields-new-insights-on-customer-behavior.html

"Quantifying Customer Response to Dynamic Pricing," with Stephen S. George, *Electricity Journal*, May 2005.

"Dynamic pricing for the mass market: California experiment," with Stephen S. George, *Public Utilities Fortnightly*, July 1, 2003, pp. 33-35.

"Toward post-modern pricing," Guest Editorial, *The Electricity Journal*, July 2003.

"Demise of PSE's TOU program imparts lessons," with Stephen S. George. *Electric Light & Power*, January 2003, pp.1 and15.

"2003 Manifesto on the California Electricity Crisis," with William D. Bandt, Tom Campbell, Carl Danner, Harold Demsetz, Paul R. Kleindorfer, Robert Z. Lawrence, David Levine, Phil McLeod, Robert Michaels, Shmuel S. Oren, Jim Ratliff, John G. Riley, Richard Rumelt, Vernon L. Smith, Pablo Spiller, James Sweeney, David Teece, Philip Verleger, Mitch Wilk, and Oliver Williamson. May 2003. Posted on the AEI-Brookings Joint Center web site, at http://www.aei-brookings.org/publications/abstract.php?pid=341

"Reforming pricing in retail markets," with Stephen S. George. *Electric Perspectives*, September/October 2002, pp. 20-21.

"Pricing reform in developing countries*," Power Economics*, September 2002, pp. 13-15.

"The barriers to real-time pricing: separating fact from fiction," with Melanie Mauldin, *Public Utilities Fortnightly*, July 15, 2002, pp. 30-40.

"The value of dynamic pricing," with Stephen S. George, *The Electricity Journal*, July 2002, pp. 45-55.

"The long view of demand-side management programs," with Gregory A. Wikler and Ingrid Bran, in *Markets, Pricing and Deregulation of Utilities*, Michael A. Crew and Joseph C. Schuh, editors, Kluwer Academic Publishers, 2002, pp. 53-68.

"Time to get serious about time-of-use rates," with Stephen S. George, *Electric Light & Power*, February 2002, Volume 80, Number 2, pp. 1-8.

"Getting out of the dark: Market based pricing can prevent future crises," with Hung-po Chao, Vic Niemeyer, Jeremy Platt and Karl Stahlkopf, *Regulation*, Fall 2001, pp. 58-62. http://www.cato.org/pubs/regulation/regv24n3/specialreport2.pdf

"Analyzing California's power crisis," with Hung-po Chao, Vic Niemeyer, Jeremy Platt and Karl Stahlkopf, *The Energy Journal*, Vol. 22, No. 4, pp. 29-52.

"Hedging Exposure to Volatile Retail Electricity Prices," with Bruce Chapman, Dan Hansen and Chris Holmes, *The Electricity Journal*, June 2001, pp. 33-38.

"California Syndrome," with Hung-po Chao, Vic Niemeyer, Jeremy Platt and Karl Stahlkopf, *Power Economics*, May 2001, Volume 5, Issue 5, pp. 24-27.

"The choice not to buy: energy savings and policy alternatives for demand response," with Steve Braithwait, *Public Utilities Fortnightly*, March 15, 2001.

"Tomorrow's Electric Distribution Companies," with K. P. Seiden, *Business Economics,* Vol. XXXVI, No. 1, January 2001, pp. 54-62.

"Bundling Value-Added and Commodity Services in Retail Electricity Markets," with Kelly Eakin, *Electricity Journal*, December 2000.

"Summer in San Diego," with Kelly Eakin, *Public Utilities Fortnightly*, September 15, 2000.

"Fighting Price Wars," *Harvard Business Review*, May-June 2000.

"When Will I See Profits?" *Public Utilities Fortnightly*, June 1, 2000.

"Mitigating Price Volatility by Connecting Retail and Wholesale Markets," with Doug Caves and Kelly Eakin, *Electricity Journal*, April 2000.

"The Brave New World of Customer Choice," with J. Robert Malko, appears in *Customer Choice: Finding Value in Retail Electricity Markets*, Public Utilities Report, 1999.

"What's in Our Future?" with J. Robert Malko, appears in *Customer Choice: Finding Value in Retail Electricity Markets,* Public Utilities Report, 1999.

"Creating Competitive Advantage by Strategic Listening," *Electricity Journal*, May 1997.

"Competitor Analysis," *Competitive Utility*, November 1996.

"Forecasting in a Competitive Environment: The Need for a New Paradigm," *Demand Forecasting for Electric Utilities*, Clark W. Gellings (ed.), 2nd edition, Fairmont Press, 1996.

"Defining Customer Solutions through Electrotechnologies: A Case Study of Texas Utilities Electric," with Dallas Frandsen et al. *ACEEE 1995 Summer Study on Energy Efficiency in Industry*. ACEEE: Washington, D.C., 1995.

"Opportunities for Energy Efficiency in the Texas Industrial Sector," *ACEEE 1995 Summer Proceedings*.

"Study on Energy Efficiency in Industry," with Jay W. Zarnikau et al. *ACEEE*: Washington, D.C., 1995.

"Promotion of Energy Efficiency through Environmental Compliance: Lessons Learned from a Southern California Case Study," with Peter F. Kyricopoulos and Ishtiaq Chisti. *ACEEE 1995 Summer Study on Energy Efficiency in Industry*. ACEEE: Washington, D.C., 1995.

"ATLAS: A New Strategic Forecasting Tool," with John C. Parker et al. Proceedings: *Delivering Customer Value, 7^{th} National Demand-Side Management Conference*. EPRI: Palo Alto, CA, June 1995.

"Emerging Technologies for the Industrial Sector," with Peter F. Kyricopoulos et al. *Proceedings: Delivering Customer Value, 7th National Demand-Side Management Conference*. EPRI: Palo Alto, CA, June 1995.

"Estimating the Revenue Enhancement Potential of Electrotechnologies: A Case Study of Texas Utilities Electric," with Clyde S. King et al. *Proceedings: Delivering Customer Value, 7th National Demand-Side Management Conference. EPRI*: Palo Alto, CA, June 1995.

"Modeling Customer Technology Competition in the Industrial Sector," *Proceedings of the 1995 Energy Efficiency and the Global Environment Conference*, Newport Beach, CA, February 1995.

"DSM opportunities for India: A case study," with Ellen Rubinstein, Greg Wikler, and Susan Shaffer, *Utilities Policy*, Vol. 4, No. 4, October 1994, pp. 285-301.

"Clouds in the Future of DSM," with G.A. Wikler and J.H. Chamberlin. *Electricity Journal*, July 1994.

"The Changing Role of Forecasting in Electric Utilities," with C. Melendy and J. Bloom. *The Journal of Business Forecasting*, pp. 3-7, Winter 1993–94. Also appears as "IRP and Your Future Role as Forecaster." *Proceedings of the 9th Annual Electric Utility Forecasting Symposium. Electric Power Research Institute (EPRI).* San Diego, CA, September 1993.

"Stalking the Industrial Sector: A Comparison of Cutting Edge Industrial Programs," with P.F. Kyricopoulos. *Proceedings of the 4CEEE 1994 Summer Study on Energy Efficiency in Buildings*. ACEEE: Washington, D.C., August 1994.

"Econometric and End-Use Models: Is it Either/Or or Both?" with K. Seiden and C. Melendy. *Proceedings of the 9th Annual Electric Utility Forecasting Symposium. Electric Power Research Institute (EPRI*). San Diego, CA, September 1993.

"Savings from Efficient Electricity Use: A United States Case Study," with C.W. Gellings and S.S. Shaffer. *OPEC Review*, June 1993.

"The Trade-Off Between All-Ratepayer Benefits and Rate Impacts: An Exploratory Study*," Proceedings of the 6th National DSM Conference*. With J.H. Chamberlin. Miami Beach, FL. March 1993.

"The Potential for Energy Efficiency in Electric End-Use Technologies," with G.A. Wikler, K.P. Seiden, and C.W. Gellings. *IEEE Transactions on Power Systems*. Seattle, WA, July 1992.

"The Dynamics of New Construction Programs in the 90s: A Review of the North American Experience," with G.A. Wikler. *Proceedings of the 1992 Conference on New Construction Programs for Demand-Side Management*, May 1992.

"Forecasting Commercial End-Use Consumption" (Chapter 7), "Industrial End-Use Forecasting" (Chapter 8), and "Review of Forecasting Software" (Appendix 2) in *Demand Forecasting in the Electric Utility Industry*. C.W. Gellings and P.E. Lilbum (eds.): The Fairmont Press, 1992.

"Innovative Methods for Conducting End-Use Marketing and Load Research for Commercial Customers: Reconciling the Reconciled," with G.A. Wikler, T. Alereza, and S. Kidwell. *Proceedings of the Fifth National DSM Conference*. Boston, MA, September 1991.

"Potential Energy Savings from Efficient Electric Technologies," with C.W. Gellings and K.P. Seiden. *Energy Policy*, pp. 217–230, April 1991.

"Demand Forecasting Methodologies: An overview for electric utilities," with Thomas Kuczmowski and Peter Lilienthal, *Energy: The International Journal*, Volume 15, Issues 3-4, March-April 1990, pp. 285-296.

"The role of demand-side management in Pakistan's electric planning," *Energy Policy*, August 1989, pp. 382-395.

"Pakistan's Economic Development in a Global Perspective: A profile of the first four decades, 1947-87," with J. Robert Malko, *Asian Profile*, Volume 16, No. 6, December 1988.

"The Residential Demand for Electricity by Time-of-Use: A survey of twelve experiments with peak load pricing," with J. Robert Malko, *Energy: The International Journal*, Volume 8, Issue 10, October 1983, pp. 781-795.

"Time-of-Use Rates and the Modification of Electric Utility Load Shapes," with J. Robert Malko, *Challenges for Public Utility Regulation in the 1980s*, edited by H.M. Trebing, Michigan State University Public Utilities Papers, 1981.

"Implementing Time-Of-Day Pricing of Electricity: Some Current Challenges and Activities," with J. Robert Malko, *Issues in Public Utility Pricing and Regulation*, edited by M. A. Crew, Lexington Books, 1980.

"Incorporating the Social Imperatives in Economic Structure: Pakistan in the years ahead," *The Journal of Economic Studies*, Volume 1, No. 1, Autumn 1974.

Appendix B: Glossary of Acronyms

Glossary of Acronyms in Testimony

DG	Distributed Generation
ECRR	Environmental Cost Recovery Rider
EER	Energy Efficiency Rider
kW	Kilowatt
kWh	Kilowatt Hour
PTS	Property Tax Surcharge
RECA	Retail Energy Cost Adjustment (Fuel Charge)
RS	Residential Service
SFV	Straight Fixed Variable
TDC	Transmission Delivery Charge
VPP	Variable Peak Pricing

Appendix C: Summary of Utility DG Rate Reform

This appendix summarizes recent activity to reform residential rates primarily in response to or in anticipation of inequities created by DG adoption and declining sales growth. A summary of the state-level activity is provided in Table 1.

Table 1: Summary of Recent DG Rate Reform Activity

State	*Utility*	Demand Charge	Fixed Monthly Charge	Capacity Charge	Streamlined Tiered Rate Structure	Time-Varying Rates	Buy-Sell Arrangement	DG-Specific Rate
Arizona	Arizona Public Service	×		✔			×	✔
Arizona	Salt River Project	✓	✓			✓		✓
California	Investor Owned Utilities		✓		✓			
California	Sacramento Municipal Utility District		✓			✓		
Connecticut	Connecticut Light and Power		✔					
Georgia	Georgia Power Co.	✔		×		✔		×
Hawaii[1]	Hawaiian Electric Co.		✓				✓	✓
Idaho	Idaho Power Co.		×	×				×
Minnesota[2]	Statewide						✓	✓
Missouri	KCP&L; Empire District Electric Co.		✓					
Nevada[3]	NV Energy		✔					
Oklahoma[4]	Statewide		✓					✓
Texas	Austin Energy						✔	✔
Utah	PacifiCorp (Rocky Mountain Power)		×					×
Washington	PacifiCorp (Pacific Power)		✓					
Wisconsin	Statewide	×	✔					

[1] HECO filed a Power Supply Improvement Planand a Distributed Generation Improvement Plan , but no formal request for a rate change has yet been filed.
[2] Minnesota currently allows buy-sell arrangements, but we have not found an example of a utility who has adopted this practice yet.
[3] NV Energy received approval for an increase in its fixed charge in its north service territory; a decision for its southern service territory is pending.
[4] State legislation allows an increase in the fixed monthly charges for DG customers, but we have not found an example of a utility who has adopted this practice yet.

Key

✔	Approved
✓	Proposed (decision pending)
×	Proposed & rejected or withdrawn

Arizona: In July 2013, Arizona Public Service (APS) proposed a new NEM policy for DG owners. APS proposed two options. The first option would put DG owners on a three-part rate and continue to compensate them for their generation at the full retail rate. The second option was a buy-sell arrangement under which DG owners would have all consumption billed under one of the existing rate options, but they would be paid a lower wholesale rate for the electricity that they generate. In November 2013, the Arizona Corporation Commission instead voted to implement a $0.70/kW capacity charge for DG owners, equating to a surcharge of roughly $5/month for a typical residential rooftop solar installation.[22]

Additionally, APS offers the most highly subscribed three-part rate in the United States. Offered on an opt-in basis since the early 1980's, approximately 10 percent of APS's residential customers are enrolled in the rate, representing roughly 20 percent of residential sales.[23] Participants face a demand charge of $13.50/kW in the summer and $9.30/kW in the winter, as well as a $16.68/month fixed charge and a time-varying energy charge.[24] The rate option is available to all residential customers including DG owners.

Salt River Project (SRP) has also proposed a new rate for DG customers. The proposal is a three-part rate and would apply only to DG customers.[25] The fixed charge would vary by a customer's amperage and ranges from $32.44/month to $45.44/month (both higher than the charge to non-DG customers). The variable charge varies by time of day and by season. The demand charge also varies by season and increases with a

[22] APS's Proposal to Change Net-Metering, ASU Energy Policy Innovation Council. Published October 2013, updated December 2013, p. 2, 3 and 5.

[23] Based on FERC Form-1 Data from 2013 and 2014.

[24] APS Rate Schedule ECT-2, Residential Service Time-of-Use with Demand Charge, Revised on July 1, 2012, p.1.

[25] Ahmad Faruqui and Ryan Hledik, "An Evaluation of SRP's Electric Rate Proposal for Residential Customers with Distributed Generation," prepared for Salt River Project, January 2015. http://www.srpnet.com/prices/priceprocess/pdfx/DGRateReview.pdf

customer's demand, ranging in the peak summer months of July and August from $8.10/kW-month for a customer's first 3 kW of demand, to $15.05/kW-month for the next 7 kW of demand, to $28.93/kW-month for demand in excess of 10 kW (with different, lower prices during other times of year). The proposal is under consideration by SRP's Board of Directors.

California: In California, two of the three investor owned utilities (IOUs) currently do not have a fixed charge in their residential rate (San Diego Gas & Electric and Pacific Gas & Electric) and the third (Southern California Edison) has a nominal fixed charge of $0.94/month[26]. All three utilities have very small minimum bill requirements. Additionally, the residential rate is an inclining block rate with four tiers. The gap in prices has grown over time and now exceeds a ratio of 2:1.[27] In ongoing proceedings on redesigning residential rates, the utilities have proposed to reduce the number of tiers from four to two and to significantly reduce the price differential. They have also proposed a fixed charge of $10/month.[28] These changes would be phased in over a four-year period, and customers would also have the option to enroll in a variety of alternative time-differentiated rates.

---

[26] Notice of Southern California Edison Company's Supplemental Filing for Residential Electric Rate Changes (R/12-06-013, Phase 1), p.1 <https://www.sce.com/wps/wcm/connect/a0984d12-3f22-45da-8495-910c0641705b/Phase1ResRateNoticeV4_English.pdf?MOD=AJPERES>

[27] PGEWebsite, <http://www.pge.com/en/myhome/saveenergymoney/plans/tiers/index.page>, accessed 12/15/2014.

[28] Renewable Energy World.com <http://www.renewableenergyworld.com/rea/news/article/2014/07/net-metering-the-great-debate>, accessed 12/19/2014.

In contrast, Sacramento Municipal Utility District (SMUD) has proposed to transition all of its residential customers to a rate with a time-varying volumetric charge and a $16/month fixed charge. The transition will occur over a multi-year period.[29]

Connecticut: Connecticut Light and Power (CL&P), a subsidiary of Northeast Utilities, recently requested an increase in its fixed charge from $16 to $25.50.[30] A December 17, 2014 decision by the Public Utilities Regulatory Authority (PURA) approved a smaller increase, raising the fixed charge to $19.25/month

Georgia: In its 2013 rate case, Georgia Power proposed a new tariff for DG customers in all classes. Specifically, the utility proposed to introduce a monthly capacity charge of $5.56/kW. For a 4 kW rooftop solar system, this translates into $22.24/month. The charge would have been entirely incremental to the existing rate. DG customers could avoid the capacity charge if they took service on a demand or RTP rate. However, in November 2013 Georgia Power withdrew its proposal as part of a settlement agreement with interveners. Residential rooftop solar owners continue to be billed under the utility's tiered rate structure, which has inclining tiers in the summer and declining tiers in the winter, and includes a

---

[29] General Manager's Report and Recommendation on Rates and Service, SMUD. May 2, 2013. Volume 1. <https://www.smud.org/en/about-smud/company-information/document-library/documents/2013-GM-Rate-Report-Vol-1.pdf>, accessed 12/17/2014.

[30] FOX CT news <http://foxct.com/2014/12/01/pura-proposal-cuts-clp-customer-increase-by-6mo/>, accessed 12/19/2014.

$10/month fixed charge.[31] In that rate case, however, Georgia Power received approval for an optional three-part tariff with a time-varying energy charge for residential customers.

Hawaii: Hawaiian Electric Company (HECO) filed a Power Supply Improvement plan (PSIP) and a Distributed Generation Improvement Plan (DGIP) before The Hawaii Public Utilities Commission on August 26, 2014. The plan includes an illustrative $55/month fixed charge for all residential customers and an additional $16/month charge for DG owners, accounting for standby generation and capacity requirements. The filing also describes a "gross export purchase model" which compensates net energy metered customers at wholesale rates for the power they contribute to the grid.[32] However, this one of several possible scenarios described in the plans, and no formal request for a rate change has yet been filed with the commission. Both the PSIP and DGIP are under review by the Hawaii Public Utilities Commission.

Idaho: In late 2012, Idaho Power proposed to increase the fixed charge for residential net metering customers from $5/month to $20.92/month. With this proposal, Idaho Power would have also established a "basic load capacity charge" of $1.48 per kilowatt that would be applied to the average of the two highest billing demands for each customer's most recent twelve

---

[31] Georgia Power Residential Service Schedule: "R-20", p.1

[32] HECO Companies Propose Significant Charges for DG Customers, Green Energy Institute, September 24, 2014. <http://law.lclark.edu/live/news/27986-heco-companies-propose-significant-charges-for-dg>, accessed on 12/14/2014.

month period. These new charges would be offset by a reduction in the energy rates paid by net metering customers. The Idaho Public Utilities Commission rejected the rate design proposal in July 2013, stating these changes could be raised again in the context of a general rate case.[33]

Louisiana: Entergy proposed to reduce the net metering payment to DG owners, in recognition that solar-powered homes aren't paying for their full use of the grid. The Louisiana Public Service Commission rejected the proposal in June 2013, but agreed to conduct a detailed study on the costs and benefits of solar, and to revisit the issue when the enrollment cap on the state's net metering policy is reached.[34]

Minnesota: Minnesota has passed legislation that will allow its utilities to use a "Value of Solar" tariff (or buy-sell arrangement) as an alternative to traditional net metering. The measures of value that will ultimately determine the payment to DG generators are energy and its delivery, generation capacity, transmission capacity, transmission and distribution line losses, and environmental value. [35]

Missouri: In October 2014, Kansas City Power & Light (KCPL) submitted a proposal requesting an increase in its fixed charge from $9 to $25. The

---

[33] The Idaho Public Utilities Commission Website <http://www.puc.idaho.gov/fileroom/cases/summary/IPCE1227.html>

[34] Bird Lori, Updates on State Solar Net Metering Activities, NREL, September 23, 2014. <http://www.cesa.org/assets/Uploads/Bird.pdf>, accessed on 12/19/2014.

[35] Minnesota Value of Solar: Methodology, Prepared for Minnesota Dept. of Commerce, Division of Energy Resource, by Clean Power Research. January 30, 2014, pp. 1, 3.

Empire District Electric Co. recently requested an increase in its fixed charge from $12.52 to $18.75.[36] Both proposals are pending approval.

Nevada: In 2013, NV Energy received approval for an increase in its fixed charge for all residential customers in its northern service territory. The fixed charge was increased from $9.25/month to $17.50/month,[37] citing a desire by the PUC to adhere to a "cost follows causation" principle. Additionally, an initial proposal in the utility's southern territory included an increase in the fixed charge from $10/month to $15.25/month. However, the utility has since modified its proposal as part of a settlement process and is now seeking a $2.75/month increase, which the Nevada PUC is considering.[38] The increase in the fixed charge would be offset by a decrease in the volumetric charge, resulting in no net change in revenue.

Oklahoma: In April 2014, Oklahoma passed Senate Bill 1456, which allows regulated utilities to charge distributed generation customers a separate rate, effective November 2014. The separate DG rate includes a fixed charge, which may be higher than the fixed charge allowed for customers within the same class who do not have distributed generation. The law does

---

[36] Midwest Energy News. <http://www.midwestenergynews.com/2015/01/06/as-in-wisconsin-missouri-utilities-seek-to-raise-fixed-charges/>

[37] SNL, "Basic service charge for many Sierra Pacific Power customers to nearly double Jan. 1," December 17, 2013. <https://www.snl.com/InteractiveX/ArticleAbstract.aspx?id=26308183>

[38] Las Vegas Review Journal <http://www.reviewjournal.com/business/energy/nv-energy-seeks-raise-customer-rates-average-282-month>, accessed 2/15/2014.

not apply to customers who installed solar panels prior to November 2014.[39] Oklahoma Gas & Electric (OG&E) is expected to include a DG tariff in their 2015 rate case.[40] Although monthly demand charges are not currently allowed by the legislation, Oklahoma Gas & Electric is considering proposing one.[41]

South Carolina: A settlement agreement reached in December 2014 between utilities, conservation groups, and solar industry groups in South Carolina outlines key provisions for DG rates. One key provision dictates that rooftop solar owners be credited at the full retail rate. Additionally, charges cannot be levied exclusively on DG owners.[42]

Texas: Austin Energy began offering a "Value of Solar" tariff in October 2012. The tariff is similar in concept to the buy-sell arrangement offered by other utilities, although the payment to DG owners includes a number of components, such as environmental value and avoided fuel hedging costs, that tend to lead to a higher price paid to DG owners. The tariff also

---

[39] Oklahoma's Senate Bill 1456.

[40] NewsOK, <http://newsok.com/oklahoma-solar-customers-may-see-charges-for-grid-costs/article/5361990>

[41] Utility DIVE. <http://www.utilitydive.com/news/oklahoma-gas-electric-considers-new-charge-for-distributed-generation/328739/>

[42] SNL Website, <https://www.snl.com/Interactivex/article.aspx?ID=30173551>, accessed 2/15/2014.

includes a floor price that ensures a minimum payment level to DG owners over a future time period.[43]

Utah: After several years of unsuccessful attempts to introduce a customer charge above $5/month, PacifiCorp (through subsidiary Rocky Mountain Power) proposed a surcharge of $4.65/month for DG customers, indicating that the charge would "produce the same average monthly revenue per customer for distribution and customer costs that is recovered in energy charges from all residential customers based on the cost of service study."[44] In its rate case testimony, the utility advised the Utah Commission that the surcharge was an interim measure and that in its next rate case it would be proposing a three-part rate designed specifically for partial requirements DG customers. The Public Service Commission of Utah did not approve the proposal, citing a need for further assessment of the costs and benefits of net metering.

Washington: PacifiCorp has proposed to increase its fixed charge from $7.75/month to $14/month. The proposal is packaged with a request for an overall rate increase. As in Utah, the utility advised the Washington Utilities and Transportation Commission that in its next rate case it would be proposing a three-part rate designed specifically for partial requirements

---

[43] Austin Energy – Value of Solar Residential Rate, DSIRE website. <http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=TX35R&re=1&ee=1>, accessed on 12/14/2014.

[44] PacifiCorp dba Rocky Mountain Power 2014 General Rate Case, Docket No. 13-035-184 < http://psc.utah.gov/utilities/electric/elecindx/2013/documents/26006513035184rao.pdf, p.20.

DG customers. A decision from the commission is expected by March 2015.[45]

Wisconsin: In June 2014, Madison Gas & Electric (MGE) proposed to eventually transition all of its residential customers to a three part rate. The rate would have included an increased fixed charge, a flat variable charge, and two different demand charges. One demand charge was based on a customer's maximum demand during any hour (designed to collect distribution costs) and the other was based on a customer's maximum demand during peak hours (designed to collect system peak-driven costs). During the interim period of transition to this three-part rate, MGE proposed a fixed charge that would escalate over a multi-year period and eventually be replaced with the demand charges. MGE ultimately withdrew this proposal, and the Wisconsin Public Service Commission is instead expected to approve a $19/month fixed charge, which is an $8.50 increase over the current fixed charge of $10.50/month.[46] The commission is also expected to approve fixed charges of $16/month for We Energies[47] and $19/month for Wisconsin Public Service Company.[48]

---

[45] Washington State Office of the Attorney General, October 10, 2014. <http://www.atg.wa.gov/pressrelease.aspx?id=32357#.VI8_MjHF_Ns>, accessed 12/15/2014.

[46] MGE website. <http://www.mge.com/about-mge/who-we-are/rate-case.htm>, accessed 12/17/2014.

[47] <http://www.jsonline.com/business/psc-begins-consideration-of-we-energies-rate-hike-plan-b99390765z1-282726581.html>, accessed 12/17/2014.

[48] <http://www.midwestenergynews.com/2014/11/11/wisconsin-fixed-charge-decision-a-sign-of-more-to-come/>, accessed 12/17/2014.

Appendix D: Modifications to Rates for Consistency with Load Research Sample

It was necessary to slightly modify the rates provided by Westar so that they would be revenue neutral for the load research sample that was used in the bill impacts analysis. In my adjustments, all of the proposed rates – for all years of the transition - were made revenue neutral to the 2015 Residential Standard Service rate for the load research sample. This allows my analysis to isolate the bill impact of a change in rate design, without assuming any change in the average rate level. The following describes the adjustments that I made to each rate. Generally, I set all charges other than the energy charge equal to the amounts provided to me by Westar, and then solve the energy charge for revenue neutrality. For rates in which the energy charge varies by tier, I maintain the price ratio between the tiers on a seasonal basis.

Residential Standard Service Rate (2015)

No changes were made to the Standard Rate for 2015. This is the rate that I used to establish the all-in revenue requirement for the load research sample. I calculated the annual revenue for all 192 customers in the load research sample under the 2015 Residential Standard Service rate to be $314,607.

Residential Demand Plan Rate (2015)

For each customer, I calculated the portion of their bill that would be determined by the fixed charge of $15 per month, the riders, and the seasonal demand charges. In other words, I calculated the non-energy portion of the bill. I summed the non-energy bills for all customers for all 12 months and then calculated the energy charge that would make up the difference between this amount and the total sample revenue requirement of $314,607. The energy charge under the Residential Demand Plan rate does not vary by season or tier.

Residential Demand Plan Rate (2019)

The methodology for calculating the revenue neutral Residential Demand Plan rate in 2019 is the same as described above for the three-part rate in 2015, but assumes a fixed charge of $27 rather than $15.

Residential Stability Plan Rate (2015–2019)

The Residential Stability Plan rate is the same for all years of the analysis. I use a fixed charge of $50 per month for each customer to calculate total monthly bills excluding energy charges. Then I calculate the revenue neutral energy charge using the same methodology described for the three part rate. The difference in the Residential Stability Plan rate is that the rate is tiered, with thresholds of 600 kWh/month for the first tier, the next 400 kWh/month for the second tier, and any remaining kWh/month for the third tier.

I calculate energy charge ratios by season and tier, based on Westar's proposed rate designs, using the winter tier 1 price as the denominator in the ratio to the other tiers. This maintains the tier price ratios across seasons.

Residential Standard Service Rate (2019)

For the 2019 Residential Standard Service rate, I use the same approach described for the Residential Stability Plan rate, but with a fixed charge of $27 per month rather than $50 per month.

Table 1 below shows the 2015 rates that Westar developed relative to the rates that I adjusted for revenue neutrality for the load research sample. Table 2 below shows the 2019 rates.

Table 1: Proposed and Revenue Neutral Rate Designs for 2015

Residential Standard Service (Proposed)

Winter			Summer		
Customer Charge	$	15.00	Customer Charge	$	15.00
1st 500 kWh	$	0.081999	1st 500 kWh	$	0.081999
Next 400 kWh	$	0.081999	Next 400 kWh	$	0.081999
All Additional kWh	$	0.068849	All Additional kWh	$	0.089497

Residential Standard Service (Revenue Neutral - Same as Proposed)

Winter			Summer		
Customer Charge	$	15.00	Customer Charge	$	15.00
1st 500 kWh	$	0.081999	1st 500 kWh	$	0.081999
Next 400 kWh	$	0.081999	Next 400 kWh	$	0.081999
All Additional kWh	$	0.068849	All Additional kWh	$	0.089497

Residential Stability Plan (Proposed)

Winter			Summer		
Customer Charge	$	50.00	Customer Charge	$	50.00
1st 600 kWh	$	0.020000	1st 600 kWh	$	0.020000
Next 400 kWh	$	0.078200	Next 400 kWh	$	0.078200
All Additional kWh	$	0.078200	All Additional kWh	$	0.090000

Residential Stability Plan (Revenue Neutral)

Winter			Summer		
Customer Charge	$	50.00	Customer Charge	$	50.00
1st 600 kWh	$	0.018721	1st 600 kWh	$	0.018721
Next 400 kWh	$	0.073200	Next 400 kWh	$	0.073200
All Additional kWh	$	0.073200	All Additional kWh	$	0.084245

Residential Demand Plan (Proposed)

Winter			Summer		
Customer Charge	$	15.00	Customer Charge	$	15.00
Energy / kWh	$	0.049000	Energy / kWh	$	0.049000
Demand / kW	$	3.00	Demand / kW	$	10.00

Residential Demand Plan (Revenue Neutral)

Winter			Summer		
Customer Charge	$	15.00	Customer Charge	$	15.00
energy / kWh	$	0.048973	energy / kWh	$	0.048973
demand / kW	$	3.00	demand / kW	$	10.00

Riders (per kWh) - Applied to All Rates

RECA	$	0.023162
TDC	$	0.014042
ECRR		-
PTS		-
EER	$	0.000280

Note: ECRR and PTS are accounted for in the energy charge of the proposed rates.

Table 2: Revenue Neutral Rate Designs for 2019

Residential Standard Service

Winter			Summer		
Customer Charge	$	27.00	Customer Charge	$	27.00
1st 500 kWh	$	0.070150	1st 500 kWh	$	0.070150
Next 400 kWh	$	0.070150	Next 400 kWh	$	0.070150
All Additional kWh	$	0.058901	All Additional kWh	$	0.076565

Residential Stability Plan

Winter			Summer		
Customer Charge	$	50.00	Customer Charge	$	50.00
1st 600 kWh	$	0.018721	1st 600 kWh	$	0.018721
Next 400 kWh	$	0.073200	Next 400 kWh	$	0.073200
All Additional kWh	$	0.073200	All Additional kWh	$	0.084245

Residential Demand Plan

Winter			Summer		
Customer Charge	$	27.00	Customer Charge	$	27.00
Energy / kWh	$	0.037290	Energy / kWh	$	0.037290
Demand / kW	$	3.00	Demand / kW	$	10.00

Riders (per kWh) - Applied to All Rates

RECA	$	0.023162
TDC	$	0.014042
ECRR		-
PTS		-
EER	$	0.000280

Note: ECRR and PTS are accounted for in the energy charge of the proposed rates.

Appendix E: The Rate Choice Model

This appendix describes the Rate Choice Model (RCM), which I used to develop estimates of customer rate switching behavior in the "Likely Choice" scenario in my testimony. The model is driven by two parameters – simply called "alpha" and "beta"– which I discuss in detail below.

The RCM belongs to a family of models referred to in the economics literature as a "multinomial logit model" or a "discrete choice model."[49] When a customer is presented with a choice of two or more electricity rates, the model captures that customer's likelihood of enrolling in each rate as a function of their average monthly bill on each rate. The logic of the model rests on the intuitive presumption is that a customer would be more likely to enroll in a rate that leads to a lower bill.

But while a customer is most likely to choose the rate that produces a lower bill, he/she will not choose that rate with complete certainty. There is some likelihood that the customer will choose one of the other available rate options. This could be because the customer is uncertain about his/her consumption profile and is not sure which rate will produce the lowest bill. It could also be the case that the customer has limited time and resources at his/her disposal to conduct the research necessary to make the optimal decision. There could also be a perception that features of the bill-minimizing rate - such as, for example, a risk of greater bill volatility - are negative attributes and would lead the customer to deliberately choose a rate that produces a higher bill that has less price volatility associated with it.

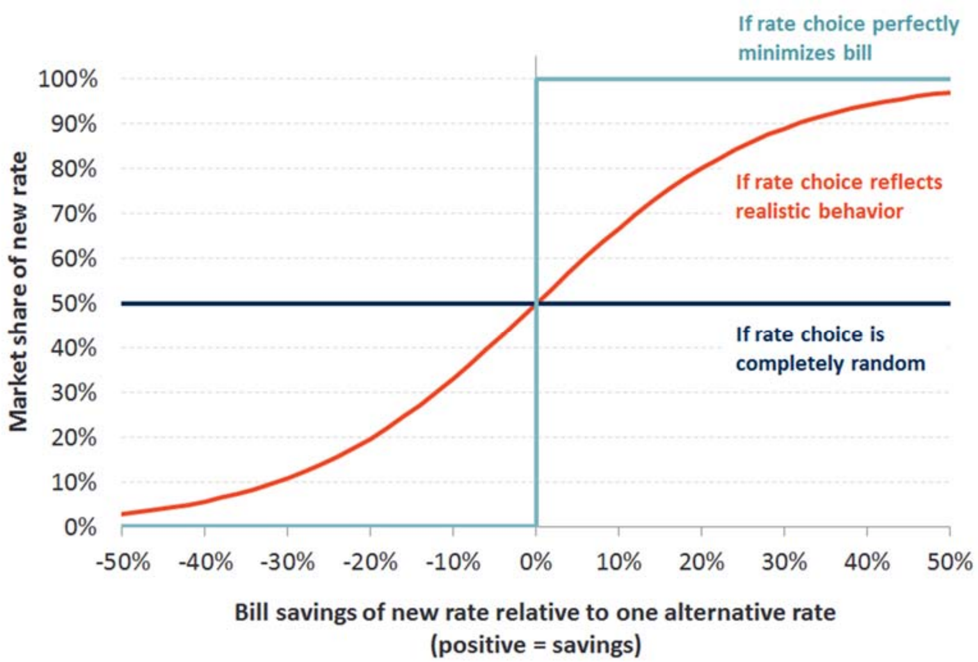
The customer's ability and willingness to choose the rate that minimizes his/her bill is represented in the model by a parameter called "beta." Beta has a negative value. The larger (i.e., more negative) the negative value, the more likely the customer is to choose the rate that minimizes his/her bill. A large beta value (e.g., -1.0) means that a customer is highly likely to

[49] Logit modeling has been used to model customer choice for decades. Nobel prize-winning economist Dan McFadden pioneered its development. See McFadden, D. (1974) "Conditional logit analysis of qualitative choice behavior" in Frontiers in Econometrics Ed. P. Zarembka New York Academic Press 105-142.

choose the rate that minimizes his/her bill, whereas a small beta value (e.g., -0.01) means that the customer is more likely to make a random rate enrollment choice.

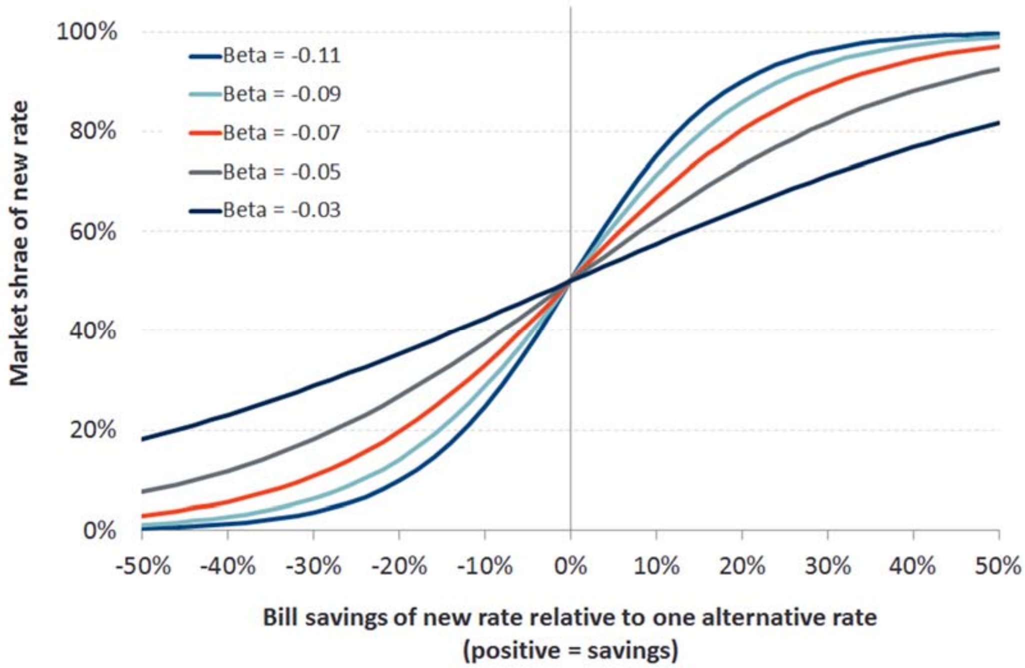
To illustrate, consider a case where a customer is faced with a choice of two new rate options. At one extreme, a price sensitive customer with perfect information would always choose to enroll in the cheapest rate, even if it saved him/her only a penny per year on his/her electricity bill. In Figure 1 below, this type of perfect least-cost behavior is represented by the light blue line. At the other extreme, a customer with no interest in his/her electricity bill would make a completely random choice of rate, regardless of the relative cost of each. This is represented by the dark blue line. In reality, the vast majority of customers will fall somewhere between these two extremes; a beta value of -0.07 represents intuitively realistic rate enrollment behavior. This is the red line. The figure illustrates a customer's likelihood of enrolling in the rate that minimizes his/her bill (the vertical axis) as a function of their monthly bill savings from enrolling in that rate (the horizontal axis).

Figure 1: Rate Adoption Curve When Choosing Between Two New Alternatives



With a beta value of -0.07, the customer's likelihood of enrolling in the cheapest rate increases with the relative bill savings associated with that rate. The customer has a 50% chance of enrolling in the cheapest rate if there are negligible bill savings (i.e., he/she is indifferent between the two rates). At bill savings of around 20%, the customer has roughly a 75% chance of enrolling in the cheapest rate. And if bill savings are expected to be 40%, the customer is more than 90% likely to enroll. The beta value can be adjusted by the RCM user to modify this relationship and move the curve between the two extreme cases discussed above. Figure 2 illustrates how the rate adoption curve changes with various assumed beta values.

Figure 2: Adoption Curve with Various Beta Value Assumptions

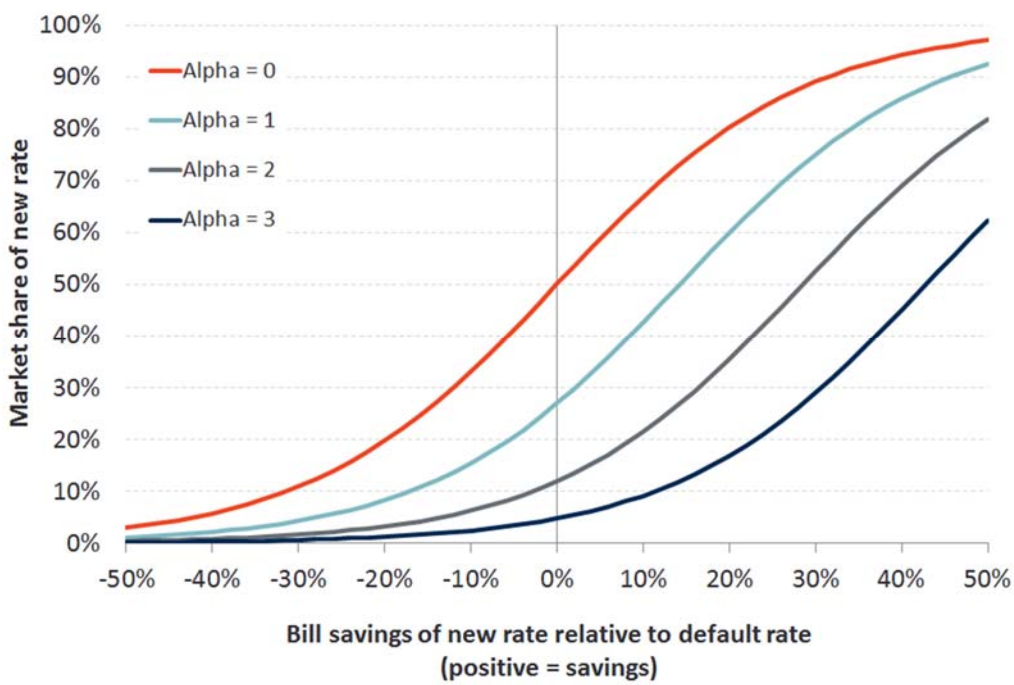


There is also a second factor that will affect a customer's decision to enroll in a new rate option. That is the presence or absence of a default rate. The example above assumes that the customer is presented with two new rate options and that the customer must choose one of those two options. In other words, in that example, the customer did not have a "default" rate in which he/she was already enrolled. When there is a default rate option (as is the case in Westar's proposal), research has found that customers have a natural tendency to remain on the default rate. There is an inherent "stickiness" associated with the default rate; customers who could save money by switching to one of the alternative new rate options demonstrate some hesitancy in doing so.

The RCM has a parameter called “alpha” that captures the “stickiness” associated with the default rate. Alpha is a positive value, and a larger alpha value means that a customer is more likely to remain on the default rate regardless of the relative attractiveness of the alternative rates. A large alpha value (e.g., 5.0) means that a customer is highly likely to remain on the default rate, whereas a low value (e.g., 0.5) value means that the customer would treat the default rate more like one of the new alternative rate options - there is less “stickiness” with a low alpha value.

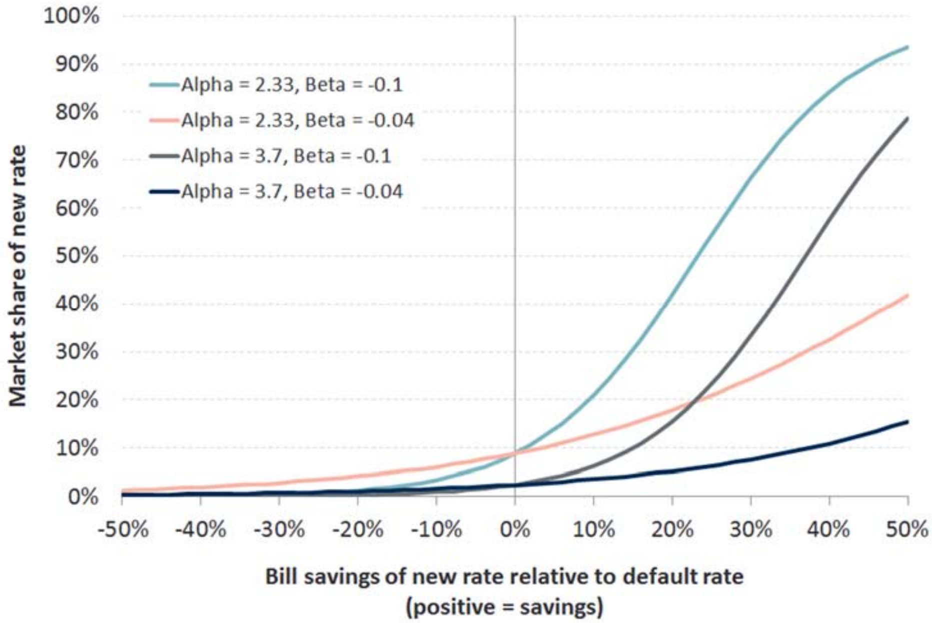
Figure 3 below illustrates how the adoption curve (with beta value of -0.07) changes with various assumptions for the value of alpha. In the figure, the customer has a choice between the default rate or one alternative new rate. With a beta value of -0.07 and an alpha of 3.0, the customer has only a 15% likelihood of switching to the new rate if it would provide bill savings of 20% and a 45% likelihood of switching if it provides bill savings of 40%.

Figure 3: Adoption Curve with Various Alpha Value Assumptions



As I described in my testimony, I analyzed two different adoption scenarios for Westar. One is anchored on roughly a 5% switching rate (consistent with alpha of 3.70) and the other is anchored on roughly a 20% switching rate (consistent with alpha of 2.33). For each of these scenarios, I tested a high beta of -0.10 and a low beta of -0.04. The adoption curves associated with each of these four cases are shown in Figure 4. The figure illustrates the choice between a default rate and one new alternative rate.

Figure 4: Four Adoption Cases Modeled in Analysis for Westar



For simplicity, the examples above illustrate a choice between just two rates. However, the RCM modeling framework can account for any number of rate choices. In Westar's proposal, there is a default rate (the "Residential Standard Service rate") and two new rate options (the "Residential Stability Plan rate" and the "Residential Demand Plan rate"). The following is a mathematical representation of the model for this scenario.

$$\text{Likelihood of Choosing Default Rate} = \frac{e^{\alpha+\beta\times \text{Bill}_d}}{e^{\alpha+\beta\times \text{Bill}_d} + e^{\beta\times \text{Bill}_1} + e^{\beta\times \text{Bill}_2}}$$

$$\text{Likelihood of Choosing Alternative Rate 1} = \frac{e^{\beta\times \text{Bill}_1}}{e^{\alpha+\beta\times \text{Bill}_d} + e^{\beta\times \text{Bill}_1} + e^{\beta\times \text{Bill}_2}}$$

$$\text{Likelihood of Choosing Alternative Rate 2} = \frac{e^{\beta\times \text{Bill}_2}}{e^{\alpha+\beta\times \text{Bill}_d} + e^{\beta\times \text{Bill}_1} + e^{\beta\times \text{Bill}_2}}$$

Where α = "alpha" value

β = "beta" value

Bill_d = customer bill on Default Rate

Bill_1 = customer bill on Alternative Rate 1

Bill_2 = customer bill on Alternative Rate 2