BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA

Nevada Power Company d/b/a NV Energy
Docket No. 15_____
Net Metering and Distributed Generation Cost of Service and Tariff Design

Prepared Direct Testimony of

Ahmad Faruqui

I. INTRODUCTION OF WITNESS

1. Q. PLEASE STATE YOUR NAME, JOB TITLE, BUSINESS ADDRESS AND PARTY FOR WHOM YOU ARE FILING TESTIMONY.

   A. My name is Ahmad Faruqui. I am a Principal with the Brattle Group. My business address is 201 Mission Street, Suite 2800, San Francisco, California 94105. I am filing testimony on behalf of Nevada Power Company d/b/a NV Energy (“Nevada Power”) and Sierra Pacific Power Company d/b/a NV Energy (“Sierra” and, together with Nevada Power, “NV Energy” or the “Companies”).

2. Q. PLEASE DESCRIBE YOUR PROFESSIONAL BACKGROUND AND EXPERIENCE.

   A. I have 35 years of consulting and research experience. During my career, I have advised several dozen utilities, private energy companies, technology providers, transmission system operators, regulatory commissions and government agencies in the United States and in Australia, Canada, Egypt, Hong Kong, Jamaica, Philippines, Saudi Arabia, South Africa and Vietnam on a wide range of customer-side issues including sales and peak demand forecasting, demand response, energy efficiency, rate design, integrated resource planning, and the use of demand-side resources to facilitate the
integration of retail and wholesale markets. I have testified or appeared before a dozen state and provincial regulatory commissions and legislative bodies. 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.

More details regarding my professional background and experience are set forth in my Statement of Qualifications, included as Exhibit Faruqui-Direct-1.

3. Q. WHAT ARE YOUR RESPONSIBILITIES AS PRINCIPAL WITH THE BRATTLE GROUP?
   A. In my current position, I lead the firm’s practice in understanding and managing the changing needs of energy consumers. This work encompasses rate design, distributed generation, energy efficiency, demand response, demand forecasting and cost-benefit analysis of emerging technologies such as advanced metering, energy storage, rooftop solar, smart thermostats and electric vehicles.

4. Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA (“COMMISSION”)?
   A. No, I have not.

II. OVERVIEW AND TESTIMONY ORGANIZATION
5. Q. WHAT IS THE PURPOSE OF YOUR PREPARED DIRECT TESTIMONY IN THIS CASE?
The purpose of my testimony is to review the new rate designs that Nevada Power and Sierra are submitting to the Commission for net energy metering (“NEM”) customers in Nevada.

6. Q. PLEASE SUMMARIZE YOUR TESTIMONY.
   A. I have reviewed the three-part rate designs for new NEM customers that are being proposed by Nevada Power and Sierra Pacific. The rates are based on marginal cost of service studies. The three-part rates include a monthly service charge, a demand charge and an energy charge. Two choices are being offered to NEM customers, one of which does not have time variation in the demand and energy charges, and one of which does have time variation in these charges. I have calibrated NV Energy’s rates against the Bonbright principles of rate design, which can be distilled into five principles: economic efficiency, equity, bill stability, revenue stability and customer satisfaction. I have found the NV Energy rates to be consistent with those principles. Finally, I have calibrated their numerical values against the three-part rate designs that are being offered by other utilities in the US and found them to be broadly in line with those of the sampled utilities.

7. Q. HOW IS YOUR TESTIMONY ORGANIZED?
   A. It is organized into several sections. Section III reviews the principles of rate design. Section IV presents NV Energy’s rate design proposal, and compares it to similar rates or rate proposals of other U.S. utilities. Section V concludes the testimony.

8. Q. ARE YOU SPONSORING ANY EXHIBITS?
   A. Yes, I sponsor the following exhibits to my testimony:

Faruqui-DIRECT
III. PRINCIPLES OF RATE DESIGN

9. Q. PLEASE PROVIDE A HISTORICAL PERSPECTIVE ON THE THEORY OF ELECTRIC RATE DESIGN.

A. The principles that guide electric rate design have evolved over time. Many authorities have contributed to their development, beginning with the legendary rate engineer John Hopkinson in the late 1800’s.¹ His thinking on the subject led him to propose a three-part tariff, consisting of a fixed service 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 Hopkinson tariff, as the demand, fixed service fee and energy charge tariff came to be called, also feature seasonal or time-of-use (“TOU”) variation corresponding to the variations in the costs of energy supply.²

British, French and American economists have made further 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

economists’ thinking in his canon, *Principles of Public Utility Rates*, which was 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*.

10. **WHAT ARE THE GENERALLY ACCEPTED RATE DESIGN PRINCIPLES?**

A. Professor Bonbright developed 10 Principles of Rate Design that are widely used as a foundation in designing rates. We have distilled these 10 principles into five Core Principles of Rate Design.

1. Economic efficiency: this principle ensures that price acts as a signal ensuring resources are not wasted. If a price is set to the incremental cost of providing a kWh, customers who value the kWh more than the cost will use it and customers who value it less will not.

2. Equity: no customer should unintentionally subsidize another customer. For example, under flat rate pricing, different load profiles mean that “peaky” customers are using electricity when it is most expensive and they are subsidized by less “peaky” customers who overpay for cheap off-peak electricity. Note that equity is not the same as social justice.

3. Revenue adequacy and stability: theoretically, all pricing schemes can be implemented to be revenue neutral within a class, but this would require perfect foresight of the future. Changing technologies and customer behaviors make load forecasting more difficult and increase the risk of the utility either under-recovering or over-recovering costs when rates are not cost reflective.

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4. Bill stability: rates should be stable and predictable. Rates that are not cost reflective are less stable over time, since both costs and loads are changing over time. For example if you spread a fixed charge over a certain number of kWh’s and the next year the number of kWh’s halves, then the price per kWh will double even though there is no change in the underlying fixed cost.

5. Customer satisfaction: for a rate to work as planned, customers need “buy in” for the rate. Because residential customers consider electricity to be a relatively low priority, rates need to be relatively simple to understand and simple to respond to. Providing choices to customers can also help, because it allows customers to better answer varying needs and risk tolerances.

Figure 1 shows the mapping between Bonbright’s original 10 principles and the Five Core Principles defined above.
Figure 1: Deriving the Five Core Principles of Rate Design

10 Bonbright Principles

1. Effectiveness in yielding total revenue requirements under the fair-return standard without any socially undesirable expansion of the rate base or socially undesirable level of product quality and safety.

2. Revenue stability and predictability, with a minimum of unexpected changes that are seriously adverse to utility companies.

3. Stability and predictability of the rates themselves, with a minimum of unexpected changes that are seriously adverse to utility customers and that are intended to provide historical continuity.

4. Static efficiency, i.e., discouraging wasteful use of electricity in the aggregate as well as by time of use.

5. Reflect all present and future private and social costs in the provision of electricity (i.e., the internalization of all externalities).

6. Fairness in the allocation of costs among customers so that equals are treated equally.

7. Avoidance of undue discrimination in rate relationships so as to be, if possible, compensatory (free of subsidies).

8. Dynamic efficiency in promoting innovation and responding to changing demand-supply patterns.

9. Simplicity, certainty, convenience of payment, economy in collection, understandability, public acceptability, and feasibility of application.

10. Freedom from controversies as to proper interpretation.

5 Core Principles

- Revenue adequacy and stability
- Bill stability
- Economic efficiency
- Equity
- Customer satisfaction

11. Q. HOW DO THESE PRINCIPLES ACCORD WITH THE WIDELY ACCEPTED NOTION OF COST CAUSATION IN RATE DESIGN?

A. Economic efficiency and equity relate directly to the notion of cost causation. Economic efficiency is achieved by having cost-reflective prices. This ensures that products are only consumed by those customers who value them at more than they cost to produce. Pricing below cost is wasteful because customers will purchase and consume products that they would not choose to consume if faced with paying full cost. Similarly, pricing above cost is wasteful because customers, who would get a net benefit from
consuming the product over its cost of production, lose out on that enjoyment. Respecting the equity principle requires that the tariff’s design not result in one customer unintentionally subsidizing another customer. This differs from social justice, which would be an intentional subsidization among customers through the tariff. Prices that are cost reflective minimize unintentional subsidies. Cost causation may need to be balanced against the other Core Principles such as customer satisfaction or bill stability.

12. Q. PLEASE SUMMARIZE THE STRUCTURE OF UTILITY COSTS?
A. In order to provide electricity to a customer, a utility must bear – directly or indirectly – costs related to energy, generation, transmission, distribution, metering and customer service (billing, customer inquiry, etc.). Generation energy costs vary directly with electricity consumption, while distribution and transmission costs vary with demand. Generation capacity costs vary with demand. Metering and customer services are a fixed cost per each customer. Some of these costs vary across time. Generation costs will vary from hour to hour depending on the marginal generation source. Distribution and transmission networks, while used year round, are sized to meet peak demand. This system peak will be split across a limited number of hours throughout the year.

13. Q. HOW DO THESE COSTS TRANSLATE INTO RATES?
A. According to the notion of cost causation, rates structure should match the nature of the costs and have a fixed service charge, a demand charge and an energy charge. The demand charge and the energy charge might vary with the time of use of electricity and have different seasonal and/or peak/off-peak charges.
14. Q. HAVE THESE COST CAUSATION PRINCIPLES BEEN APPLIED IN PRACTICE?
   A. Yes, most commercial and industrial customers across the U.S. are served under cost-reflective three-part rate structures.

15. Q. HAVE THESE COST CAUSATION PRINCIPLES BEEN APPLIED TO RESIDENTIAL CUSTOMERS?
   A. Historically they have not, however this is changing rapidly due to several technological advances that have emerged in the last several years. As described in the Summary of Residential Three-Part Tariffs that is attached as Exhibit Faruqui Direct-2, at least 19 utilities in 14 states are currently offering three-part rates to residential customers. Exhibit Faruqui Direct-3 discusses rate reforms which for the most part aim at modifying rates to make them more cost-reflective. For instance, as shown in Table 1 of Exhibit Faruqui Direct-3, most of the rate changes discussed in other US jurisdictions include an increase in fixed the charge or minimum bill, proposed to better reflect the utilities’ costs in the rates.

16. Q. WHAT TECHNOLOGICAL ADVANCES HAVE LEAD TO INCREASED USE OF THREE-PART RATE STRUCTURES FOR RESIDENTIAL CUSTOMERS?
   A. Smart meters are capable of recording advanced billing functions such as incremental consumption and demand, thereby removing a large barrier/cost to the dissemination of cost-reflective rates (since additional specialized meters are no longer required). In addition, smart meters can provide feedback to customers on their electricity usage in real or near-real time and also communicate with devices in the home. This allows a customer to
clearly understand their electricity usage and manage their bills in a way that was not widely available before.

The introduction of renewable DG, coupled with the two-part rate structure, has resulted in the shifting of costs and revenue requirement. Utilities receive less revenue from customers who pay two-part rates after the customer installs renewable DG; yet, fixed and demand costs incurred to serve the customer are largely not reduced. Responsibility for these costs is then shifted to other customers, thereby shifting costs from customers who install renewable DG to other customers. In short, customers who install renewable DG are subsidized by customers who do not when a simple two-part rate design that relies primarily on volumetric rates to recover demand and fixed costs continues to be used. In these circumstances, the benefits of cost-reflective rates (due to decreases in equity and efficiency) are larger than before.

17. Q. WHY IS THERE A COST SHIFT?
   A. The cost shift occurs because the current flat/volumetric rate includes several fixed cost and demand-based elements. Customers who self-generate can reduce the amount of energy that they receive from the utility and thereby avoid paying for these fixed and demand elements.

IV. THE RATE DESIGN PROPOSAL
18. Q. WHAT ARE THE CURRENT RATE DESIGNS FOR NV ENERGY’S NEM CUSTOMERS?
   A. Residential NEM customers at Nevada Power and Sierra currently pay the same rate as their otherwise applicable tariff schedule. This includes a
monthly service charge (called the Basic Service Charge or “BSC”) and a volumetric rate. Customers have a choice of a flat volumetric rate or a TOU volumetric rate. Both are described for Nevada Power and Sierra in Table 1. It is important to note that 99% of residential customers have chosen the flat rate and 1% have chosen the TOU rate.

Table 1: Current Residential Rate Design

<table>
<thead>
<tr>
<th></th>
<th>Fixed Charged ($/kW)</th>
<th>Variable Charge ($/kWh)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>Flat rate</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Summer On</td>
</tr>
<tr>
<td>Sierra Flat rate</td>
<td>15.25</td>
<td>0.09842</td>
</tr>
<tr>
<td>Sierra TOU rate</td>
<td>15.25</td>
<td>0.41175</td>
</tr>
<tr>
<td>Nevada Flat rate</td>
<td>12.75</td>
<td>0.11642</td>
</tr>
<tr>
<td>Nevada TOU rate</td>
<td>12.75</td>
<td>0.36709</td>
</tr>
</tbody>
</table>

Source: NVE Net metering proposal July 16, 2015 presentation
Notes: Chart excludes Generation Meter Charge that is waived for Solar Generations customers

Any excess production from the customer’s self-generation facility is subject to the NEM arrangement. Under this arrangement, the customer is credited for the excess kWh production on the otherwise applicable tariff schedule. This credit goes into a “bank” account which will be used to pay for kWh consumption either in the current or future billing period.

19. Q. **WHY IS IT NECESSARY TO CHANGE THE CURRENT RATE STRUCTURE FOR NEM CUSTOMERS?**

A. The current two-part NEM rate structure has two shortcomings – it shifts revenue requirements (and therefore electricity costs) from NEM to non-NEM customers, thereby raising the bills for non-NEM customers, and it
does not account for any incremental costs that NEM customers may place upon the system, which again means that bills for non-NEM customers are raised.

20. Q. PLEASE DESCRIBE THE COST SHIFT CAUSED BY THE CURRENT RATE STRUCTURE FOR NEM CUSTOMERS.

A. The standard two-part residential rate consists largely of a volumetric rate which covers several cost elements, some of which are volumetric and some of which are not. Energy costs are volumetric, while distribution, transmission and the capacity component of generation costs are not. NEM customers will upload power to the grid in some periods and offload power in others, sometimes even within a single hour. Even though their net energy consumed may be zero, they have still been using the grid extensively in aggregate. Under the current NEM rate structure, any electricity exported onto the grid will earn a credit at the full retail rate which includes the cost of the grid as well as the cost of energy.

These credits reduce the contribution that NEM customers make toward the costs of transmission and distribution assets, but do not proportionately reduce the costs that they impose on the grid. For example, if the volumetric rate is 10 cents, and the cost of energy (scaled to recover revenue) is four cents, then the remaining six cents will be used to cover the costs of the grid and customer services. On a particular day, if a NEM customer exports five kWh of energy onto the grid, the NEM customer will receive a credit for each kWh, totaling 50 cents. However, the NEM customer would not have reduced the costs the utility incurs by 50 cents, but only by 20 cents (five kWh times four cents). This creates a revenue shortfall of 30 cents which...
then must be recovered from the non-NEM customers, thereby creating a 
cost shift from non-NEM customers to NEM customers.

21. **Q. WHO PAYS FOR THIS COST SHIFT?**  
   A. Currently, all non-NEM customers pay for the NEM cost shift.

22. **Q. PLEASE DESCRIBE THE POTENTIAL INCREMENTAL COSTS THAT NEM CUSTOMERS IMPOSE ON THE UTILITY?**  
   A. Serving and signing up NEM customers requires additional support staff to activate the new NEM accounts, answer customer inquiries and handle the advanced billing required due to the NEM credits. Other costs such as integrating renewables into the grid may also be applicable, but are not included in the current rates calculations.

23. **Q. WHAT NEW RATE DESIGNS FOR NEM CUSTOMERS ARE THE COMPANIES PROPOSING?**  
   A. Two new rate designs are being proposed. The first one is a three-part rate where the demand and energy charges do not have a time-of-use component. The second one is also a three-part rate, but its demand and energy charges have a TOU component. These rates are shown in Table 2.

<table>
<thead>
<tr>
<th>Flat rate</th>
<th>TOU rate</th>
<th>Summer On Peak</th>
<th>Winter On Peak</th>
<th>Variable Charge ($/kWh)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Sierra Flat rate</td>
<td>24.50</td>
<td>8.63</td>
<td>0.04749</td>
<td>0.08694</td>
</tr>
<tr>
<td>Sierra TOU rate</td>
<td>24.50</td>
<td>4.46</td>
<td>14.66</td>
<td>1.43</td>
</tr>
<tr>
<td>Nevada Flat rate</td>
<td>18.15</td>
<td>14.33</td>
<td>0.0547</td>
<td>0.09147</td>
</tr>
<tr>
<td>Nevada TOU rate</td>
<td>18.15</td>
<td>4.04</td>
<td>22.15</td>
<td>0.05036</td>
</tr>
</tbody>
</table>

Source: Rate Summary_SPPC and NPC.xlsx
Notes: Chart excludes Generation Meter Charge that is waived for Solar Generations customers
24. **Q. WILL THE NEM RATES BE MODIFIED OVER TIME?**  
   A. All rates are subject to change as the underlying cost drivers and load changes. The numerical parameters of the rates, such as the basic service charge, the demand charge and the energy charge, should be updated periodically in a general rate case to reflect changes in the marginal costs and loads that determine the rates. Structurally, the rates should remain unchanged unless it is shown that the three-part rate no longer adequately reflects the underlying cost elements.

25. **Q. HAVE YOU SEEN THE RESULTS OF THE MARGINAL COST OF SERVICE STUDIES FOR NEM CUSTOMERS FILED BY THE COMPANIES?**  
   A. Yes, I have seen the results of the studies.

26. **Q. ARE THE RATES DEVELOPED BY NV ENERGY CONSISTENT WITH THE RESULTS OF THE COST OF SERVICE STUDIES?**  
   A. Yes, the three-part rates developed directly reflect the different cost elements from the cost of service studies, scaled so as to recover the revenue requirement.

27. **Q. HAVE YOU SEEN THE RESULTS OF THE JULY 2014 COST-BENEFIT ANALYSIS (CALLED “NEVADA NET ENERGY METERING IMPACTS EVALUATION”) PREPARED BY E3?**  
   A. Yes, I have seen the results of that analysis.
28. Q. WHAT IS THE PURPOSE OF A MARGINAL COST OF SERVICE STUDY WHEN SUCH A COST-BENEFIT ANALYSIS IS AVAILABLE?

A. Prices send signals to customers about what actions to take and to the utility about what investments to make. If these price signals are cost reflective, then optimal decisions will be made that raise economic efficiency and enhance customer well-being, making society better off. Marginal cost of service studies establish a measure of long-run marginal costs for various aspects of utility costs. If these costs are then passed on to customers with minimal distortions (distortions are needed for revenue recovery), then customers will pay cost-reflective prices that enable them to make optimal decisions. A cost-benefit study does not estimate marginal costs or prices of any kind. Rather, it focuses on whether a specific investment, policy or program is desirable or not. For these reasons, cost-benefit studies are not suitable for determining rates.

29. Q. ARE THE NEWLY DESIGNED RATES CONSISTENT WITH THE COMPANIES’ COST OF SERVICE STUDIES?

A. Yes, the rates are based on their cost of service studies.

30. Q. HAVE YOU REVIEWED SENATE BILL 374 FROM THE 2015 SESSION OF THE NEVADA LEGISLATURE (“SB 374”)?

A. Yes, I have.

31. Q. WHAT ARE THE RELEVANT ASPECTS OF SB 374 WITH RESPECT TO NEM RATE DESIGN?
A. SB 374 directs the Commission to develop new NEM rules and rates that ensure that costs are not shifted from NEM customers to non-NEM customers. Section 2.3.e of SB 274 states that the Commission shall not authorize

"Any rates or charges for net metering that unreasonably shift costs from customer-generators to other customers of the utility."

Section 4.5 of SB 374 states that the proposed NEM rate may include:

"(a) A basic service charge that reflects marginal fixed costs incurred by the utility to provide service to customer-generators;
(b) A demand charge that reflects the marginal demand costs incurred by the utility to provide service to customer-generators; and
(c) An energy charge that reflects the marginal energy costs incurred by the utility to provide service to customer-generators."

32. Q. IS THE THREE-PART RATE DESIGN PROPOSED BY THE COMPANIES CONSISTENT WITH THE REQUIREMENTS OF SB 374?

A. Yes, it is. The Companies have conducted marginal cost of service studies for NEM customers by treating them as their own customer class, both in terms of costs incurred to serve them and load shapes used to derive marginal cost revenue. These cost of service studies were then used to derive class-specific factors for several NEM-only customer classes. The proposed NEM rates provide NEM customers a choice between a simple three-part rate and a time varying three-part rate. It is my belief that the proposed rates are
consistent with the principles of cost-causation and that they largely eliminate subsidies from non-NEM to NEM customers as required by SB 374 section 2.3e. In accordance with section 4.5, the rates include a basic service charge that reflects marginal fixed costs incurred by the Companies to serve NEM customers; a demand charge that reflects the marginal demand costs incurred by the Companies to serve NEM customers; and an energy charge that reflects the marginal energy costs incurred by the Companies to serve NEM customers.

33. Q. HAVE THREE-PART RATES BEEN PROVIDED TO RESIDENTIAL NEM CUSTOMERS IN OTHER U.S. JURISDICTIONS?

A. Yes, at least three U.S. utilities are currently offering three-part rates to residential NEM customers in three different states, as described in Exhibit Faruqui-Direct-2. These three-part rates include a fixed charge, a demand or capacity charge and a variable energy charge. All three rates are (or will be) applicable to all customers who elect to install a new grid-connected NEM system. These utilities are Salt River Project in Arizona, South Carolina Public Service Authority in South Carolina and We Energies in Wisconsin. Other utilities have proposed a three-part rate specific to NEM customers, such as UNS Energy in Arizona, but these rates have not been approved yet. Three-part rates have a long history for larger commercial and industrial customers, including NEM customers.

Furthermore, Exhibit Faruqui Direct-3 gives an overview of the current DG related reform landscape in the U.S. Several other U.S. jurisdictions and

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5 WE Energies has published its new NEM specific rates but will these will only be applicable after January 1, 2016.
6 See Exhibit Faruqui Direct-3.
utilities are proposing to change their rates. Some utilities only apply fixed charge increases for all residential customers (including DG customers), some design a three-part rate structure specific to NEM customers, while other utilities design a buy-sell arrangement through which the utility pays the customer-generator a volumetric rate for the electricity generated by the customer-generator that is different than the rate the customer-generator pays the utility for bundled electric service. Table 1 in Exhibit Faruqui Direct-3 attempts to give an overview of these proposed changes. All rate proposals discussed are driven by a similar cost recovery issue and aim at implementing a rate structure that better reflects cost causation.

34. Q. HAVE TIME-VARYING CHARGES OR CHARGES VARYING BY SEASON BEEN INCLUDED IN RATES OFFERED BY OTHER UTILITIES FOR NEM CUSTOMERS?

A. Yes, time-varying demand and energy charges are not uncommon for rates offered to NEM customers. For instance, the Salt River Project offers a rate to NEM customers with time-varying demand and time-varying energy charges that also vary seasonally (Winter, Summer and Summer Peak). South Carolina Public Service Authority, often known as Santee Cooper, also offers energy charges that vary with both the season and the time of day. Exhibit Faruqui Direct-3 also discusses several examples of proposed rates with time-varying charges for NEM customers.
35. **Q. IS IT POSSIBLE TO COMPARE NV ENERGY’S PROPOSED THREE-PART RATE TO THOSE OFFERED BY UTILITIES IN OTHER STATES?**

A. Yes, but any such comparison should recognize the fact that different utilities have different costs to serve\(^7\) and thus different overall rate levels.

Figure 2 shows the average volumetric rate in 2014 for all residential customers (NEM and non-NEM) for utilities offering three-part rates. The average rate is derived by dividing residential class revenue requirements by class sales. Figure 2 shows a circumscribed set of these utilities, limited to the 18 (out of 28) utilities for whom average volumetric rate data was readily available.\(^8\)\(^9\) Although both Nevada Power’s and Sierra Pacific’s average residential rates are generally in line with the U.S. average rate of 12.5 cents/kWh,\(^10\) they are at the higher end relative to the comparison group of utilities that offer three-part rates and have data readily available. This indicates that Nevada Power and Sierra Pacific are most likely in the higher range of the spectrum in terms of costs of service compared to the rest of the comparison group. This context should be recognized in the rate comparisons.

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\(^7\) Not only do the utilities have different costs to serve, but they also base their rates on different kinds of cost of service studies, some of which are marginal cost studies and some of which are embedded cost studies.

\(^8\) Only those utilities whose rates were included in the Edison Electric Institute (EEI) Typical Bills and Average Rates Report Winter 2015 were included.

\(^9\) If no separate DG class is defined, these rates will also apply to DG customers.

36. **Q. HOW DO NV ENERGY’S PROPOSED THREE-PART RATES COMPARE TO THREE-PART RATES OFFERED BY UTILITIES IN OTHER STATES?**

A. Figures 3 through 7 hereafter compare the fixed charge, the demand charge and the energy charge offered by Nevada Power and Sierra to three-part rates offered by other utilities. Both the flat and the three-part TOU rates are shown in all instances. All figures differentiate rates offered only to NEM customers (grey) from rates offered to all customers. All Nevada Power and Sierra rates are shown in as diagonal stripes.
Figure 3 shows NV Energy’s proposed fixed charges for their residential three-part NEM rates compared to those from other utilities offering three-part rates. These charges are at the higher end of the spectrum, but do not stand out as outliers. They are significantly lower than some of the NEM-only fixed charges being offered by other utilities.

Figure 3: Comparison of Fixed Charges between Utilities

In Figure 4 and Figure 5, we compare NV Energy’s set of proposed demand charges to those from other utilities offering three-part rates. In general, none of the components of NV Energy’s proposed rates are materially out of bounds with the other utilities’ demand rates. Demand charges vary along a number of dimensions including the length of the demand charge period and whether the demand charge is coincident with the utility’s peak demand or based on the customer’s maximum
demand regardless of time of occurrence. Some of these rates are explored in more
detail in Exhibit Faruqui Direct-2. The basic three-part rate structure proposed by
NV Energy has a non-coincident demand charge, while the TOU rate schedule has
both a non-coincident and coincident demand charge. For ease of comparison, we
have separated coincident and non-coincident (max demand) demand charges in
both Figure 4 and Figure 5. Figure 4 shows the summer demand charge. The
maximum demand charges for the flat three-part rates are on the higher end of the
spectrum, but are not outliers. The maximum demand charges for the TOU rates are
very low, but the rates also include a coincident demand charge. The coincident
demand charge for the TOU rates is again on the higher end of the spectrum, but in
line with other NEM-only coincident demand charges. Figure 5 shows the winter
demand charge. The maximum demand charges for the flat three-part rates are again
on the higher end of the spectrum, but are not outliers, while the winter coincident
peak charge for the TOU rate is by far the lowest (Nevada Power has a zero winter
coincident peak charge).
Figure 4: Comparison of Summer Demand Charges between Utilities

Notes:
1) All rates apart from Westar and UNS are drawn from their respective utility tariff sheets, valid as of July 2015.
2) At the date of filing, the Westar and UNS rates are only proposed and pending approval.
3) For Nevada TOU 3 Part Rate and Sierra TOU 3 Part Rate, if Max Demand occurs during the Coincident Peak Period then the Max and Coincident Charges are added together to make the rate $9.12/kW-month for Sierra TOU 3 Part Rate and $22.3/kW-month for Nevada TOU 3 Part Rate.
Figure 5: Comparison of Winter Demand Charges between Utilities

Figure 6 and Figure 7 show summer and winter energy charges respectively. Nevada Power’s and Sierra’s energy charges appear to be in the middle of the spectrum.

Notes:
1) All rates apart from Westar and UNS are drawn from their respective utility tariff sheets, valid as of July 2015.
2) At the date of filing, the Westar and UNS rates are only proposed and pending approval.
3) For Nevada TOU 3 Part Rate and Sierra TOU 3 Part Rate, if Max Demand occurs during the Coincident Peak Period then the Max and Coincident Charges are added together to make the rate $5.89/kW-month for Sierra TOU 3 Part Rate.
Figure 6: Comparison of Summer Energy Charges between Utilities

Notes:
1) All rates apart from Westar and UNS are drawn from their respective utility tariff sheets, valid as of July 2015.
2) At the date of filing, the Westar and UNS rates are only proposed and pending approval.
3) For UNS, the option to have a TOU feature is proposed.
V. CONCLUSION

37. WHAT ARE YOUR CONCLUSIONS ABOUT NV ENERGY’S RATE PROPOSAL FOR NEM CUSTOMERS

A. I find that NV Energy’s proposed NEM rates meet the widely held principles of rate design and are reasonable in magnitude compared to similar rates in other jurisdictions. NV Energy’s rates are derived from marginal cost of service studies and are consistent with the principles of economic efficiency and equity (no unintentional subsidization). Compared to the existing NEM rate, which is mostly a volumetric rate, the fixed charge and the demand charge of the new NEM rate offer month-to-month bill stability for customers and revenue stability for the utility. Since the rate is only applicable to new NEM customers, there are no issues with bill shocks or...
need for transition to the new rate. NEM customers are offered a choice of two rates and a simple and clear rate design meeting the principle of customer satisfaction.

38. Q. DOES THIS COMPLETE YOUR TESTIMONY?
   A. Yes, it does.
STATEMENT OF QUALIFICATIONS

DR. AHMAD FARUQUI

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

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

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

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

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

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

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

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

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

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

**AREAS OF EXPERTISE**

- **Innovative pricing.** He has identified, designed and analyzed the efficiency and equity benefits of introducing innovative pricing designs such as 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**

- 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.

**Colorado**

• 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

• 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.

Kansas


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


New Mexico

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

Pennsylvania


REGULATORY APPEARANCES

Arkansas


Delaware


Kansas


Ohio


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


**Technical Reports**


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


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=e5b59c3e26805e2c6b9e469cb9c1855a9b0f18c67bbe7d8d4ca08a8abd39c54d


• “Study Ontario for TOU Lessons,” Intelligent Utility, April 1, 2014.


  http://www.fortnightly.com/archive/puf_archive_0311.cfm
  http://www.fortnightly.com/archive/puf_archive_1110.cfm
• “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/S0360544209003387
  http://www.utilityweek.co.uk/news/news_story.asp?id=123888&title=Dynamic+tariffs+are+vital+for+smart+meter+success
  http://www.cato.org/pubs/regulation/regv31n4/v31n4-noted.pdf
  http://www.fortnightly.com/exclusive.cfm?o_id=94
  http://www.drscoalition.org/resources/other/Pricing_Programs_TOU_and_RTP.pdf
• “Demand Response and Advanced Metering,” Regulation, Spring 2006. 29:1 24-27.  
• “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


• “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.


### Summary of Residential Three-Part Tariffs

<table>
<thead>
<tr>
<th>#</th>
<th>Utility</th>
<th>Utility Ownership</th>
<th>State</th>
<th>Residential Customers Served</th>
<th>Effective Date of Rate</th>
<th>Demand Charge Peak ($/kW-month)</th>
<th>Timing of Demand Measurement</th>
<th>Demand Charge Peak Hours</th>
<th>Combined with Energy TOU?</th>
<th>Applicable Residential Customer Segment</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Nevada Power (3 Part Rate)</td>
<td>Investor Owned</td>
<td>NV</td>
<td>757,888</td>
<td>Proposed</td>
<td>18.12</td>
<td>Any time</td>
<td>15 min</td>
<td>NA</td>
<td>NA</td>
</tr>
<tr>
<td>2</td>
<td>Nevada Power (TOU 3 Part Rate)</td>
<td>Investor Owned</td>
<td>NV</td>
<td>757,888</td>
<td>Proposed</td>
<td>18.12</td>
<td>Any time</td>
<td>15 min</td>
<td>13:00 - 19:00</td>
<td>Yes</td>
</tr>
<tr>
<td>3</td>
<td>Sierra Pacific Power (3 Part Rate)</td>
<td>Investor Owned</td>
<td>NV</td>
<td>281,282</td>
<td>Proposed</td>
<td>24.50</td>
<td>Any time</td>
<td>15 min</td>
<td>NA</td>
<td>NA</td>
</tr>
<tr>
<td>4</td>
<td>Sierra Pacific Power (TOU 3 Part Rate)</td>
<td>Investor Owned</td>
<td>NV</td>
<td>281,282</td>
<td>Proposed</td>
<td>24.50</td>
<td>Any time</td>
<td>15 min</td>
<td>13:00 - 18:00</td>
<td>Yes</td>
</tr>
<tr>
<td>5</td>
<td>Alabama Power</td>
<td>Investor Owned</td>
<td>AL</td>
<td>1,241,998</td>
<td>10/1/2011</td>
<td>14.50</td>
<td>Any time</td>
<td>15 min</td>
<td>NA</td>
<td>NA</td>
</tr>
<tr>
<td>6</td>
<td>Alaska Electric Light and Power</td>
<td>Investor Owned</td>
<td>AK</td>
<td>13,968</td>
<td>9/2/2011</td>
<td>11.49</td>
<td>Peak Coincident</td>
<td>60 min</td>
<td>12:00 - 19:00</td>
<td>Yes</td>
</tr>
<tr>
<td>7</td>
<td>Arizona Public Service</td>
<td>Investor Owned</td>
<td>AZ</td>
<td>3,019,212</td>
<td>7/1/2012</td>
<td>16.94</td>
<td>Any time</td>
<td>15 min</td>
<td>17:00 - 21:00</td>
<td>Yes</td>
</tr>
<tr>
<td>8</td>
<td>Black Hills Power</td>
<td>Investor Owned</td>
<td>SD</td>
<td>54,637</td>
<td>4/1/2015</td>
<td>13.00</td>
<td>Peak Coincident</td>
<td>60 min</td>
<td>12:00 - 19:00</td>
<td>Yes</td>
</tr>
<tr>
<td>9</td>
<td>Black Hills Power</td>
<td>Investor Owned</td>
<td>WY</td>
<td>2,135</td>
<td>10/1/2014</td>
<td>13.50</td>
<td>Any time</td>
<td>15 min</td>
<td>13:00 - 19:00</td>
<td>Yes</td>
</tr>
<tr>
<td>10</td>
<td>City of Fort Collins Utilities</td>
<td>Municipal</td>
<td>CO</td>
<td>60,464</td>
<td>1/1/2015</td>
<td>5.32</td>
<td>Peak Coincident</td>
<td>60 min</td>
<td>7:00 - 9:00</td>
<td>No</td>
</tr>
<tr>
<td>11</td>
<td>City of Kinston</td>
<td>Municipal</td>
<td>NC</td>
<td>9,776</td>
<td>5/1/2005</td>
<td>14.02</td>
<td>Any time</td>
<td>15 min</td>
<td>7:00 - 9:00</td>
<td>No</td>
</tr>
<tr>
<td>12</td>
<td>City of Longmont</td>
<td>Municipal</td>
<td>CO</td>
<td>34,397</td>
<td>1/1/2014</td>
<td>15.40</td>
<td>Peak Coincident</td>
<td>13:00 - 19:00</td>
<td>No</td>
<td>No</td>
</tr>
<tr>
<td>13</td>
<td>Dakota Electric Association</td>
<td>Cooperative</td>
<td>MN</td>
<td>94,924</td>
<td>9/1/2014</td>
<td>11.00</td>
<td>Any time</td>
<td>15 min</td>
<td>13:00 - 19:00</td>
<td>No</td>
</tr>
<tr>
<td>14</td>
<td>Dominion</td>
<td>Investor Owned</td>
<td>NC</td>
<td>101,138</td>
<td>1/1/2014</td>
<td>16.53</td>
<td>Peak Coincident</td>
<td>30 min</td>
<td>6:30 - 12:00 17:00 - 21:00</td>
<td>Yes</td>
</tr>
<tr>
<td>15</td>
<td>Dominion</td>
<td>Investor Owned</td>
<td>VA</td>
<td>2,105,300</td>
<td>1/1/2015</td>
<td>12.00</td>
<td>Peak Coincident</td>
<td>30 min</td>
<td>7:00 - 11:00 17:00 - 21:00</td>
<td>Yes</td>
</tr>
<tr>
<td>16</td>
<td>Duke Energy Carolinas, LLC</td>
<td>Investor Owned</td>
<td>NC</td>
<td>1,608,151</td>
<td>7/1/2015</td>
<td>13.38</td>
<td>Peak Coincident</td>
<td>60 min</td>
<td>12:00 - 19:00</td>
<td>Yes</td>
</tr>
<tr>
<td>17</td>
<td>Duke Energy Carolinas, LLC</td>
<td>Investor Owned</td>
<td>SC</td>
<td>460,178</td>
<td>11/1/2014</td>
<td>9.93</td>
<td>Peak Coincident</td>
<td>30 min</td>
<td>7:00 - 12:00</td>
<td>Yes</td>
</tr>
<tr>
<td>18</td>
<td>Fort Morgan</td>
<td>Municipal</td>
<td>CO</td>
<td>5,273</td>
<td>2/1/2015</td>
<td>4.35</td>
<td>Any time</td>
<td>15 min</td>
<td>13:00 - 19:00</td>
<td>No</td>
</tr>
<tr>
<td>19</td>
<td>Georgia Power</td>
<td>Investor Owned</td>
<td>GA</td>
<td>20,72,262</td>
<td>4/1/2015</td>
<td>10.00</td>
<td>Peak Coincident</td>
<td>60 min</td>
<td>13:00 - 19:00</td>
<td>Yes</td>
</tr>
<tr>
<td>20</td>
<td>Midwest Energy Inc</td>
<td>Cooperative</td>
<td>KS</td>
<td>29,951</td>
<td>7/1/2015</td>
<td>22.00</td>
<td>Any time</td>
<td>15 min</td>
<td>13:00 - 19:00</td>
<td>No</td>
</tr>
<tr>
<td>21</td>
<td>Otter Tail Power Company</td>
<td>Investor Owned</td>
<td>MN</td>
<td>47,689</td>
<td>10/1/2015</td>
<td>16.00</td>
<td>Peak Coincident</td>
<td>60 min</td>
<td>13:00 - 19:00</td>
<td>Yes</td>
</tr>
<tr>
<td>22</td>
<td>Otter Tail Power Company</td>
<td>Investor Owned</td>
<td>ND</td>
<td>44,910</td>
<td>12/1/2009</td>
<td>18.38</td>
<td>Any time</td>
<td>60 min</td>
<td>13:00 - 19:00</td>
<td>No</td>
</tr>
<tr>
<td>23</td>
<td>Otter Tail Power Company</td>
<td>Investor Owned</td>
<td>SD</td>
<td>8,648</td>
<td>6/1/2011</td>
<td>13.00</td>
<td>Peak Coincident</td>
<td>60 min</td>
<td>13:00 - 19:00</td>
<td>No</td>
</tr>
<tr>
<td>24</td>
<td>Salt River Project</td>
<td>Political Subdivision</td>
<td>AZ</td>
<td>891,668</td>
<td>4/1/2015</td>
<td>32.44 or 45.48</td>
<td>Peak Coincident</td>
<td>30 min</td>
<td>13:00 - 20:00 5:00 no</td>
<td>Yes</td>
</tr>
<tr>
<td>25</td>
<td>South Carolina Public Service Authority</td>
<td>State</td>
<td>SC</td>
<td>140,126</td>
<td>2/1/2016</td>
<td>24.00</td>
<td>Peak Coincident</td>
<td>30 min</td>
<td>13:00 - 19:00</td>
<td>No</td>
</tr>
<tr>
<td>26</td>
<td>South Carolina Public Service Authority</td>
<td>State</td>
<td>SC</td>
<td>140,126</td>
<td>12/1/2014</td>
<td>22.00</td>
<td>Peak Coincident</td>
<td>60 min</td>
<td>13:00 - 19:00</td>
<td>No</td>
</tr>
<tr>
<td>27</td>
<td>Swanton Village Electric Department</td>
<td>Municipal</td>
<td>VT</td>
<td>3,208</td>
<td>9/1/2014</td>
<td>26.57</td>
<td>Peak Coincident</td>
<td>13:00 - 19:00</td>
<td>No</td>
<td>No</td>
</tr>
<tr>
<td>28</td>
<td>UNS Energy</td>
<td>Investor Owned</td>
<td>AZ</td>
<td>81,399</td>
<td>Proposed</td>
<td>20.00</td>
<td>Peak Coincident</td>
<td>60 min</td>
<td>13:00 - 19:00</td>
<td>No</td>
</tr>
<tr>
<td>29</td>
<td>We Energies</td>
<td>Investor Owned</td>
<td>WI</td>
<td>984,860</td>
<td>1/1/2016</td>
<td>17.86</td>
<td>Peak Coincident</td>
<td>60 min</td>
<td>13:00 - 19:00</td>
<td>No</td>
</tr>
<tr>
<td>30</td>
<td>Westar Energy</td>
<td>Investor Owned</td>
<td>KS</td>
<td>323,581</td>
<td>Proposed</td>
<td>15.00</td>
<td>Peak Coincident</td>
<td>60 min</td>
<td>13:00 - 19:00</td>
<td>No</td>
</tr>
<tr>
<td>31</td>
<td>Xcel Energy (PSCo)</td>
<td>Investor Owned</td>
<td>CO</td>
<td>1,182,098</td>
<td>7/1/2012</td>
<td>12.23</td>
<td>Peak Coincident</td>
<td>60 min</td>
<td>13:00 - 19:00</td>
<td>No</td>
</tr>
</tbody>
</table>
Westar Energy’s rate has been proposed by the utility in an ongoing regulatory proceeding but has not yet been approved.

Blacks Hills also offers an optional time of use rate that includes both energy and demand charges for customers owning demand controllers, these are smart home energy controllers that limit maximum demand. Rate also includes a three month shoulder period during which the energy charge is always equal to the 5.8049 cents per kWh off-peak rate (months of October, April, & May).

Mandatory if customer consumes more than 5,000 kWh per month for three consecutive months or has a recorded peak demand of 20 kW for three consecutive months. The rate also includes a summer mid-peak period for energy.

The monthly fixed charge is a daily basic service charge multiplied by 30.5 days.

Blacks Hills also offers an optional time of use rate that includes both energy and demand charges for customers owning demand controllers, these are smart home energy controllers that limit maximum demand.

The demand charge is tiered and applies to demand with thresholds of the first 3 kW, the next 7 kW, and all remaining kW. Energy and demand charges vary across three seasons: Winter, Summer (May, June, September, and October), and On-Peak Summer (July and August). All energy and demand charges shown here apply for the On-Peak Summer period. The utility is experimentally offering the rate plan to a limited number of non-DG customers.

The rate plan is proposed and pending approval. The proposed rate is mandatory for new DG customers and optional for other residential customers. For the energy charge, the option to have a time of use feature is also proposed. The rate is mandatory for DG customers with an aggregate nameplate rating of less than 300 kW. The monthly fixed charge is the daily generation facilities charge plus a DG rider multiplied by 30.5 days. If exports to the grid exceed delivered energy in a particular month then the difference is credited at 4.245 cents per kWh.

Peak periods are applicable from Monday through Friday excluding following holidays: New Year’s Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day, and Christmas. For some utilities, the monthly fixed charge has been calculated by multiplying a daily charge by 30.5. Rates that are applicable to DG customers only are for the most part mandatory and applicable only to new customers after the rates come into effect.

[2]: If max demand in summer occurs during the Coincident Peak period then the max demand charge (4.04 dollars per kW) and coincident demand charge (22.15 dollars per kW) are added together to make the demand charge: 26.19 dollars per kW. Otherwise the demand charge is simply equal to the max demand charge.

[3]: The demand charge is based on the higher of maximum demand or 80% of the average maximum demand for the last three summer months.

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

[5]: The demand charge is tiered and applies to demand with thresholds of the first 3 kW, the next 7 kW, and all remaining kW. Energy and demand charges vary across three seasons: Winter, Summer (May, June, September, and October), and On-Peak Summer (July and August). All energy and demand charges shown here apply for the On-Peak Summer period. The utility is experimentally offering the rate plan to a limited number of non-DG customers.

[6]: Demand will be the greater of the measured demand for the current month or 85% of the highest recorded demand established during the preceding eleven months.

[7]: This rate plan is proposed and pending approval. The proposed rate is mandatory for new DG customers and optional for other residential customers. For the energy charge, the option to have a time of use feature is also proposed. The rate is mandatory for DG customers with an aggregate nameplate rating of less than 300 kW. The monthly fixed charge is the daily generation facilities charge plus a DG rider multiplied by 30.5 days. If exports to the grid exceed delivered energy in a particular month then the difference is credited at 4.245 cents per kWh.

[8]: Westar Energy’s rate has been proposed by the utility in an ongoing regulatory proceeding but has not yet been approved.

Sources: Utility’s tariffs and “Form EIA-861 2013 data files, EIA_861_Retail_Sales_2013.xls"(for Utility, State, and Residential Customers Served columns)

Notes:

If max demand in summer occurs during the Coincident Peak period then the max demand charge (4.04 dollars per kW) and coincident demand charge (22.15 dollars per kW) are added together to make the demand charge: 26.19 dollars per kW. Otherwise the demand charge is simply equal to the max demand charge.

If max demand occurs during the Coincident Peak period then the max demand charge (4.46 dollars per kW) and coincident demand charge (14.66 dollars per kW in summer and 1.43 dollars per kW in winter) are added together to make the demand charge : 19.12 dollars per kW in summer and 5.89 dollars per kW in winter. Otherwise the demand charge is simply equal to the max demand charge. The rate also includes a summer mid-peak period for energy.

Rate also includes a three month shoulder period during which the energy charge is always equal to the 5,8049 cents per kWh off-peak rate (months of October, April, & May).

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

The monthly fixed charge is a daily basic service charge multiplied by 30.5 days.

Demand charge is the sum of the distribution demand charge and the generation demand charge. Energy charges are the sum of the generation kWh charge, transmission kWh charge, and distribution kWh charge. The distribution demand charge is 1.612 dollars per kW and the generation demand charge is 4.070 dollars per kW for the summer and 2.334 dollars per kW for the winter. The transmission charge is .970 cents per kWh and the distribution charge is .892 cents per kWh. The generation charge is 2.843 cents per kWh for peak and 0.915 cents per kWh for off-peak hours.

Demand period is not explicitly identified and it is assumed to be maximum demand.

Demand is measured as the maximum winter demand for the most recent 12 months. New customers have an assumed demand of 3 kW for their first year. Fixed charge for MN is customer charge per month plus facilities charge per month.
Summary of Utility Distributed Generation (‘‘DG’’) Rate Reform

This exhibit 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 in seventeen different states is provided in, Table 1, followed by descriptions of activities on a state by state basis.

Table 1: Recent Rate Reform Options by State

<table>
<thead>
<tr>
<th>State</th>
<th>Utility</th>
<th>Demand Charge</th>
<th>Seasonal or TOU Demand Charges</th>
<th>Fixed Monthly Charge</th>
<th>Increase of Fixed Charge or Minimum Bill</th>
<th>Capacity Charge</th>
<th>Streamlined Tiered Rate Structure</th>
<th>Seasonal or TOU Energy Charges</th>
<th>Buy-Sell Arrangement</th>
<th>DG-Specific Rate</th>
</tr>
</thead>
<tbody>
<tr>
<td>[1] Arizona</td>
<td>Arizona Public Service</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>[10] Idaho</td>
<td>Avista</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>[12] Illinois</td>
<td>Statewide</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>[14] Missouri</td>
<td>Ameren</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
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<td></td>
</tr>
<tr>
<td>[16] Missouri</td>
<td>KCP&amp;L</td>
<td></td>
<td></td>
<td></td>
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<td></td>
<td></td>
<td></td>
<td></td>
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<tr>
<td>[17] Oklahoma</td>
<td>Statewide</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>[18] South Carolina</td>
<td>South Carolina Public Service Authority</td>
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<td></td>
<td></td>
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<td></td>
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<tr>
<td>[19] Texas</td>
<td>Austin Energy</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
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<td></td>
</tr>
<tr>
<td>[20] Utah</td>
<td>PacifiCorp (Rocky Mountain Power)</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>[22] Washington</td>
<td>PacifiCorp (Pacific Power)</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>[23] Wisconsin</td>
<td>WE Energies</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Key:
✓ Approved
✓ Proposed (decision pending)
✓ Proposed & rejected or withdrawn

Notes:
This table shows changes in rate structure as an evolution to existing rates. Common features between new and proposed as well as existing rate structures are not reflected here. Streamlined Tiered Rate Structure refers to energy charges. The Capacity Charge column refers to a charge based on the capacity of the solar panels installed. An increase in the fixed charge was approved in December 2014. However, Senate Bill 570, which would result in a decrease in the fixed charge, has passed in the Senate and failed upon adjournment in the House.

An increase in the fixed charge was approved in December 2014. However, Senate Bill 570, which would result in a decrease in the fixed charge, has passed in the Senate and failed upon adjournment in the House. The capacity charge proposed was to be calculated on the basis of the customer’s peak demand over the past twelve months. Unlike other reforms referred to in the capacity charge column, this capacity charge does not depend on the size of the solar panel installation.

A proposed senate bill aims at adding a demand charge in the current residential rate design.

Not Energy offers subscribers of its “Solar Rewards Community Garden” program a buy-sell arrangement type of contract.

State legislation allows for 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.
1. Arizona

In July 2013, Arizona Public Service (“APS”) proposed a new net metering policy for DG owners. APS proposed two rate 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 total amount of electricity that they generate. In November 2013, the Arizona Corporation Commission (“ACC”) instead voted to implement a $0.70/kW charge on installed solar PV capacity, equating to a surcharge of roughly $5/month for a typical residential rooftop solar installation.1 In April 2015, APS requested an increase in this charge to $3.00/kW or $21/month for a typical residential rooftop solar installation.2 The request is currently pending. However, the ACC staff has asked the Commission to reject the increase and ask the company to include it in its next general rate case application.3

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.4 Participants face a demand charge of $13.50/kW in the summer and $9.30/kW in the winter, as well as a $16.96/month fixed charge and an

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4. Based on FERC Form-1 Data from 2013 and 2014.
energy charge that varies with the season and time of day (peak versus off-peak). The rate option is available to all residential customers including DG owners.

Salt River Project ("SRP") offers a rate for DG customers different from the rates offered to other residential customers. This rate was approved by SRP’s Board of Directors in February 2015. It is a three-part rate which only applies to DG customers. The fixed charge varies by a customer’s amperage and ranges from $32.44/month to $45.44/month (both higher than the charge to non-DG customers). It is meant to recover the costs of billing and metering, customer service and distribution facilities. The variable charge varies by time of day and by season. The demand charge also varies by season and increases with a customer’s demand, ranging in the peak summer months of July and August from $9.59/kW-month for a customer’s first 3 kW of demand, to $17.82/kW-month for the next 7 kW of demand, to $34.19/kW-month for demand in excess of 10 kW (with different, lower prices during other times of year). The standard rate for non-DG residential customers is a two-part rate with a fixed charge and a volumetric charge (with an optional Time-of-Use ("TOU") feature). A three-part rate is also being offered experimentally to a limited number of non-DG customers through the “Pilot Price Plan For Residential Demand Rate Service". The rates offered by this plan are identical to the three-part rate offered to DG customers.

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5 APS Rate Schedule ECT-2, Residential Service Time-of-Use with Demand Charge, Revised on July 1, 2012, page 1. Note: daily rate = $0.556 * 30.5 days.
9 Ibid., page 30.
10 Ibid., pages 34 - 39.
UNS Energy Corporation (the Arizona-based parent company of Tuscon Electric Power and UniSource Energy Services) asked the ACC to approve a three-part rate for DG customers who submit connections to new DG facilities after June 1, 2015. The fixed rate would be $20/month while the residential rate currently has a $10/month fixed charge. The demand charge proposed has a tiered structure. An optional TOU feature would be offered for the energy charge. This new three-part rate would also be proposed as an optional rate to non DG residential customers beginning May 1, 2016. Additionally, the utility is proposing to purchase excess energy from new rooftop systems using the Renewable Credit Rate (that would be set on the market price of power generated by large solar arrays). This will initially be set at 5.84 cents per kWh and updated on an annual basis. Currently, residential customers are offered a two-part rate with a fixed rate and an energy charge (with the option of a TOU feature). Currently, DG customers can participate in a Net Metering program in which excess generation is credited at the the standard retail rate.

13 “Rate Application.”, UNS, <https://www.uesaz.com/doc/UNSE_Rate_Application.pdf>
2. California

In October 2013, California Assembly Bill 327 (“AB 327”) was enacted, directing the California Public Utility Commission (“CPUC”) to reform residential rates including minimum bill and customer charges up to $10/month and develop a new rate for DG customers by December 31, 2015.\(^\text{16}\) This state legislation requires deriving a new framework from the analysis of the benefits and costs that distributed generation produces for the grid and for the public. The rates will be derived using a marginal cost based cost of service study. This initiative is called “NEM 2.0”.\(^\text{17}\)

Concerning residential rates applicable to all customers, two of the three investor owned utilities (“IOUs”) currently do not have a fixed charge (San Diego Gas & Electric and Pacific Gas and Electric) and the third (Southern California Edison) has a nominal fixed charge of $0.94/month.\(^\text{18}\) All three utilities have minimum bill requirements ranging from $2/month and $5/month.\(^\text{19}\) On July 3, 2015, the CPUC voted unanimously to make two structural changes to the rate design: requiring the utilities to implement default TOU rates by January 2019 and reducing the number of rate tiers from four to two. This decision also postponed consideration of levying a monthly fixed charge until at the earliest 2018, when default TOU rates have been put in place.\(^\text{20}\) However, in the CPUC’s NEM 2.0 proceeding, utilities may propose fixed charges that would apply to residential net metering customers.\(^\text{21}\) In addition, the CPUC decision raised the maximum fixed charge included on the minimum bill to $10/month for non-CARE (California

\(^{16}\) Assembly Bill No. 327, California State Assembly, approved October 7, 2013. [http://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201320140AB327]

\(^{17}\) “Rooftop Solar 2.0 – Hawaii and California grapple over net energy metering.”, Published on July 2, 2015, in Fortnightly, accessed on July 2, 2015, [http://www.fortnightly.com/fortnightly/2015/06/rooftop-solar-20]


\(^{19}\) Decision on Residential Rate Reform, California Public Utilities Commission, p. 218, July 3, 2015, [http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M153/K024/153024891_PDF]

\(^{20}\) “Calif. regulators approve major overhaul of residential electric rate design”, published on July, 3 2015 in SNL Financials.

Alternate Rates for Energy)\(^{22}\) customers and $5/month for CARE customers.\(^{23}\) The decision states this rate design change “will allow for more accurate allocation of costs and for energy rates to more fairly reflect the cost of service”.\(^{24}\)

Sacramento Municipal Utility District (“SMUD”) has a default two-part rate for all of its residential customers a consisting of a volumetric charge (which varies with season) and a $16/month fixed charge.\(^{25}\) This rate also has an optional TOU feature. In 2013, the Board approved a transition plan to eliminate the tiered structure of the volumetric charge by 2017.\(^{26}\) At the start of 2015, SMUD increased its fixed charge from $14/month to $16/month,\(^{27}\) and going forward, SMUD’s fixed charge will increase to $18/month in 2016 and to $20/month in 2017, as established by the Board in 2011. SMUD has also proposed a new optional rate for residential customers beginning in 2016. This proposed rate includes only three volumetric charges, year round peak and off-peak prices and a summer super peak price. This proposed TOU rate moves SMUD closer to what it expects to propose as the standard residential rate design for its customers in 2018.\(^{28}\)

\(^{22}\) The CARE program provides lower rates to low-income customers.


\(^{24}\) Ibid., page 1.


\(^{28}\) Ibid. pages 13-17.
3. Colorado

As part of an investigation on DG related issues opened by the Public Utilities Commission of Colorado in March 2014, the staff said in July 2014 that the Commission has the authority to create separate rate classes for DG customers. In the June 2015 staff comments, the staff recommended that customer’s excess energy rate credit be less than the retail rate they pay for electricity. The staff also recommended including a TOU rate to all residential customer rates and a minimum bill charge for DG customers that would be set at an amount that will ensure that the utility is revenue neutral.

4. Connecticut

Connecticut Light and Power (CL&P), a subsidiary of Northeast Utilities, requested an increase in its fixed charge from $16.00 to $25.50 in its 2014 rate case. A December 2014 decision by the Public Utilities Regulatory Authority (“PURA”) approved a smaller increase, raising the fixed charge to $19.25/month. More recently, in June 2015, the Senate passed Senate Bill 570, which caps the fixed charge that residential customers pay at $10/month. Although the bill passed unanimously in the Senate, it failed upon adjournment in the House.

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30 Trial staff’s initial brief in response to the Commission’s questions regarding Net Metering, Proceeding No. 14M-0235E, July 31, 2014.
5. Georgia

In its 2013 rate case, Georgia Power proposed a rate specific to DG customers, referred to as “Supplemental Power Service”. The utility proposed to introduce a monthly charge of $5.56/kW of installed solar PV capacity to be added as a surcharge to existing residential rates.36 However, in November 2013, Georgia Power withdrew its proposal as part of a settlement agreement with interveners, approved by the Commission in December 2013.37 Residential rooftop solar owners continue to be billed under the utility’s current tiered rate structure available for all residential customers, which has inclining tiers in the summer and declining tiers in the winter, and includes a $10/month fixed charge.38 The DG specific rate was rejected, but Georgia Power received approval for an optional three-part tariff with a TOU energy charge for residential customers in that same rate case.39

Georgia Power filed an update to the 2013 Rate Case Order and Settlement Agreement in October 2014, proposing to adjust the traditional base tariffs but with no change to the rate design. This was approved in December 2014 and came into effect in January 2015.40

6. Hawaii

Hawaiian Electric Company (“HECO”) filed a Power Supply Improvement Plan (“PSIP”)41 and a Distributed Generation Improvement Plan (“DGIP”)42 before the Hawaii Public Utilities Commission.

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40 Order Approving Tariffs Subject to Refund in Re: Georgia Power Company’s Update of Base Tariffs, Georgia Public Service Commission, Docket No. 36989, December 18, 2014.
on August 26, 2014 with several possible new rate design scenarios for DG customers. 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.\(^4\) In January 2015, HECO proposed to the Commission to repeal net energy metering and replace it with a transition tariff ("TDG") that would cut the rate credit for power sold back to the grid by a factor of about 50%. The proposal also mentioned implementing a monthly fixed charge of $55/month for all residential customers and an additional $16/month charge for DG owners. The Commission judged HECO’s proposal as “insufficiently supported” and refused to rule at this time.\(^{44}\)

On June 29, 2015, HECO submitted another request to the Hawaii Public Utilities Commission in which they asked again to withdraw their current net metering program in favor of a smaller energy credit that would be assigned a dollar value, which could be used to offset monthly bills.\(^{45}\) Rather than a fixed charge, this proposal includes a $25 minimum monthly bill for all future residential PV customers to all islands. Currently, the minimum monthly bill is $17.00 on O‘ahu, $18.00 on Maui, and $20.50 on Hawaii Island.\(^{46}\) HECO also recommends a pilot TOU rate, which would be a voluntary program to new DG customers.

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\(^46\) Ibid., page 2.
7. Idaho

In late 2012, Idaho Power proposed to increase the fixed charge for residential net metering customers from $5.00/month to $20.92/month. With this proposal, Idaho Power would have also established a “basic load capacity charge” of $1.48 per kilowatt to “reflect the full cost-of-service associated with their use of the distribution system”. 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.

Avista filed a Rate Case in May 2015 in which it asked Idaho Public Utilities Commission (IPUC) to increase its fixed and variable rates. The proposed fixed charge increase would be from $5.25 to $8.00 per month.

8. Illinois

In March 2015, SB 1879 and HB 3328 were introduced in Illinois’ state Senate and Assembly and proposed, among a number of items concerning Illinois’ electric grid, to add a demand charge to the current residential rates design. HB 3328 missed its legislative deadline and is re-referred back to the
House Rules Committee\(^{51}\) while SB 1879 passed the Senate Energy and Public Utilities Committee but is awaiting action on the Senate floor.\(^{52}\)

9. Louisiana

Entergy proposed to reduce the net metering payment to DG owners for their excess generation, 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\(^{53}\), 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.\(^{54}\) The Commission released the study in March 2015, stating that net metered solar owners pay only a portion of what they cost to utilities although Entergy has not yet made a follow-up proposal request to the Commission.\(^{55}\)

10. Minnesota

In March 2014,\(^{56}\) Minnesota passed legislation that will allow its utilities to use a “Value of Solar” (“VOS”) tariff (type of 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

Minnesota’s VOS policy will have a fixed price (or will have a set inflation rate over time) for the electricity the customer generates, set by a 25-year contract between the solar generator and the utility. The electricity generated would be credited at this rate on the customer’s bill.\footnote{“If 'value of solar' is optional, will Minnesota utilities adopt it?,” Midwest Energy News, Published April 9, 2014, <http://midwestenergynews.com/2014/04/09/if-value-of-solar-is-optional-will-minnesota-utilities-adopt-it/>., Accessed July 27, 2015} In Xcel Energy’s testimony to the Public Utilities Commission in February 2014, the utility estimated that the VOS energy charge would be 14.5 cents per kWh, which was higher than its residential rate at the time (11.5 cents per kWh).\footnote{“Shining Rewards,” Environment America, Published June 2015, <http://www.environmentamerica.org/sites/environment/files/reports/EA_shiningrewards_print.pdf>, Accessed July 27, 2015.} Xcel Energy updated their estimate of the VOS energy charge in April 2015 to a lower rate of 13.6 cents/kWh. The VOS energy charge would be adjusted for inflation using either a long term fixed rate or the Urban Consumer Price Index (CPI).

Utilities have the possibility to offer both options (VOS and traditional net metering) to their customers, but, according to a report published by Environment America in June 2015, “not a single Minnesota utility opted into the value-of-solar program.”\footnote{“Minnesota will 'get the ball rolling’ on community solar today,” Midwest Energy News, Published December 12, 2014, http://midwestenergynews.com/2014/12/12/minnesota-will-get-the-ball-rolling-on-community-solar-today>, Accessed July 27, 2015.}

11. Missouri

In October 2014, Kansas City Power & Light ("KCP&L") submitted a proposal requesting an increase in its fixed charge from $9/month to $25/month. In August 2014, the Empire District Electric Co. also requested an increase in its fixed charge from $12.52/month to $18.75/month.62 In June 2015, the Missouri Public Service Commission decided the fixed monthly customer charge for Empire District Electric Co. would stay at $12.52/month.63

In July 2014, Ameren Missouri also requested to increase their fixed charges from $8.00 to $8.77/month. In April 2015, the Missouri Public Service Commission approved a smaller rate increase with no increase in fixed charge.64

12. Oklahoma

In April 2014, Oklahoma passed Senate Bill 1456, which allows regulated utilities to charge DG 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 not apply to customers who installed solar panels prior to November 2014.65 Oklahoma Gas & Electric ("OG&E") and Public Service Company of Oklahoma

63 “PSC Issues Decision In The Empire District Electric Company Rate Case,” Missouri Public Service Commission, June 25, 2015,<http://psc.mo.gov/Electric/PSC_Issues_Decision_In_The_Empire_District_Electric_Company_Rate_Case>
(“PSO”) both plan to include a Distributed Generation Tariff to their rate cases expected by the end of 2015.66 A demand charge is also being considered by both utilities, although this type of charge is currently not allowed by the legislation, so would be more difficult to implement.67 OG&E cites that they “would prefer to deal with a distributed generation tariff as part of its upcoming rate case.”68

13. South Carolina

South Carolina Public Service Authority currently offers its DG customers a three-part rate which includes a fixed charge of $24/month, demand charges that vary for On-Peak and Off-Peak hours, and base energy charges that vary on both the time of year and time of day.69 The utility also has a net-metering program in which it offers its customers credits “based on the net On-Peak and net Off-Peak kilowatt hours purchased from or delivered to the Authority for the billing month.” Non-DG customers are also offered a similarly structured three-part rate, however they are charged a lower fixed charge of $22/month.70

14. Texas

Austin Energy began offering a Value of Solar (“VOS”) 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

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includes a number of components, such as environmental value and avoided fuel hedging costs, which tend to lead to a higher price paid to DG owners. The tariff also includes a floor price that ensures a minimum payment level to DG owners over a future time period.\footnote{Austin Energy – Value of Solar Residential Rate, DSIRE website. \ltt{http://programs.dsireusa.org/system/program/detail/5669}, Accessed December 14, 2014.}


\section*{15. Utah}

After several years of unsuccessful attempts to introduce a fixed 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.”\footnote{PacifiCorp dba Rocky Mountain Power 2014 General Rate Case, Docket No. 13-035-184, p.20 \ltt{http://psc.utah.gov/utilities/electric/elecindx/2013/documents/26006513035184rao.pdf}.} 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

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\textsuperscript{71} Austin Energy – Value of Solar Residential Rate, DSIRE website. \ltt{http://programs.dsireusa.org/system/program/detail/5669}, Accessed December 14, 2014.
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costs and benefits of net metering. The commission set up a public hearing for October 2015 to discuss this matter further. However, the decision by the Commission approved an increase in the customer charge from $5.00/month to $6.00/month as well as an increase in the minimum bill from $7.00/month to $8.00/month for residential customers.

16. Washington

In May 2014 PacifiCorp proposed to increase its fixed charge from $7.75/month to $14/month, which was rejected by the Washington Utilities and Transportation Commission in March 2015. The proposal was packaged with a request for an overall rate increase with no increase to the fixed charge. The commission accepted a smaller rate increase for PacifiCorp than was requested, citing that these were the “reasonable” rates. 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 DG customers.

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Avista filed a request with the Washington Utilities and Transportation Commission in February 2015 to increase its electric and natural gas rates. The filing includes a request to increase the monthly basic charge from $8.50/month to $14.00/month, and a decision is expected by January 2016.80

17. Wisconsin

As approved by the Commission in December 2014, WE Energies will offer a three-part rate to DG customers with less than 300 kW of installed capacity as of January 2016. The rate consists of a fixed charge of about $17.86/month81, a demand charge that depends on the class and voltage usage of the customer, and either a flat energy rate or an energy rate that depends on the time of year, time of day and voltage.82 The company credits net energy supplied by the customer using the Buy-Back Energy Rate which differs with the customer’s rate schedule. Standard Residential Customers are offered a two part rate that includes a daily fixed charge (lower than the one in the new DG rate) and an energy charge which can be either flat83 or dependent on the time of use.84

81 The monthly fixed charge is the daily generation facilities charge plus a DG rider multiplied by 30.5 days. This calculation is (0.05951*30.5)+(0.52602*30.5).
AFFIRMATION

STATE OF California
COUNTY OF Contra Costa

I, AHMAD FARUQUI, do hereby swear under penalty of perjury the following:

That I am the person identified in the attached Prepared Testimony and that such testimony was prepared by me or under my direct supervision; that the answers and information set forth therein are true to the best of my knowledge and belief; and that if asked the questions set forth therein, my answers thereto would, under oath, be the same.

AHMAD FARUQUI 07/28/2015

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

State of California
County of Contra Costa

Subscribed and sworn to (or affirmed) before me
on this 28th day of July, 2015.
by

(1) AHMAD FARUQUI —

proved to me on the basis of satisfactory evidence to be the person who appeared before me.

Signature — MUKESH P. PATEL

Signature of Notary Public