BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MONTANA

____________________________________________________
PREFILED DIRECT TESTIMONY
OF
AHMAD FARUQUI
ON BEHALF OF
NORTHWESTERN ENERGY

____________________________________
DOCKET NO. D2018.2.12
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I. INTRODUCTION

Q. WHAT ARE YOUR NAME AND ADDRESS?
A. My name is Ahmad Faruqui. I am a Principal with the Brattle Group, an economics consulting firm. My address is 201 Mission Street, Suite 2800, San Francisco, California 94105.

Q. ON WHOSE BEHALF ARE YOU SUBMITTING TESTIMONY?
A. I am testifying on behalf of NorthWestern Energy (“NorthWestern”).

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?
A. The purpose of my testimony is to present my proposal, on behalf of NorthWestern, to create a separate rate class for future net energy metering (NEM) customers and to modify the current rate design for those customers.¹ I focus specifically on the residential class.²

Q. HOW IS YOUR TESTIMONY ORGANIZED?
A. My testimony is organized into several sections:
   • The remaining subsections of Section I present my qualifications, provide an executive summary, and provide a brief summary of the residential NEM rate proposal.

¹ Existing NEM customers would be grandfathered into the existing residential rate class. Section 69-8-612, MCA.
² While the issues I discuss and analyze in my testimony also exist for non-residential NEM customers, as a first step I focus on analysis of residential customers. I discuss why this is appropriate later in my testimony.
Section II discusses the generally accepted principles of rate design.

Section III describes the reasons for creating a separate rate class for future NEM customers.

Section IV discusses the structure of, and support for, a three-part rate design for NEM customers in the separate rate class.

Section V discusses NorthWestern’s proposal to increase the customer charge in its residential rates.

Section VI concludes my testimony.

Several appendices are attached to my testimony, including a glossary of acronyms in Appendix A, a survey of fixed charges for residential customers in Montana and investor-owned utilities (IOUs) in neighboring states in Appendix B, a survey of U.S. utilities offering demand charges to residential customers in Appendix C, a survey of Montana utilities offering a demand charge to commercial and industrial (C&I) customers in Appendix D, details on an alternative two-part rate with a higher basic service charge on NEM customers in Appendix E, a description of the load research sample data in Appendix F, the methodology employed to calculate the proposed three-part rate in Appendix G, and my resume in Appendix H.

\section*{I.A. Qualifications}

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

A. I am an energy economist. My consulting practice is focused on customer-related issues. My areas of expertise include rate design, demand response, energy efficiency, distributed energy resources, advanced metering
infrastructure, plug-in electric vehicles, energy storage, inter-fuel substitution, combined heat and power, microgrids, and demand forecasting.

I have worked for nearly 150 clients on 5 continents. These include electric and gas utilities, state and federal commissions, independent system operators, government agencies, trade associations, research institutes, and manufacturing companies. I have testified or appeared before commissions in Alberta (Canada), Arizona, Arkansas, California, Colorado, Connecticut, Delaware, the District of Columbia, FERC, Illinois, Indiana, Kansas, Maryland, Minnesota, Nevada, Ohio, Oklahoma, Ontario (Canada), Pennsylvania, ECRA (Saudi Arabia), and Texas. Also, I have presented to governments in Australia, Canada, Egypt, Ireland, the Philippines, Thailand and the United Kingdom and given seminars on all 6 continents.

I hold B.A. and M.A. degrees from the University of Karachi, Pakistan, an M.A. in agricultural economics and a Ph.D. in economics from the University of California at Davis.

More details regarding my professional background and experience are set forth in my Statement of Qualifications, included in Appendix H.

Q. HAVE YOU PREVIOUSLY TESTIFIED ON THE TOPIC OF RATE DESIGN FOR NEM CUSTOMERS?

A. Yes. I have filed testimony on this topic in Arizona, Nevada, Kansas, and Idaho. Details are provided in Appendix H.

I.B. EXECUTIVE SUMMARY

Q. HOW WOULD YOU SUMMARIZE YOUR TESTIMONY?

A. To ensure that its residential rate offering is consistent with the generally accepted principles of rate design, I am proposing the creation of a separate rate class for future residential NEM customers and a mandatory three-part rate design for customers in that class. The rate will consist of a basic service fee ($/month), a volumetric charge ($/kWh), and a demand charge ($/kW-month).

Q. WHY DOES YOUR PROPOSAL ADDRESS RATES ONLY FOR FUTURE RESIDENTIAL NEM CUSTOMERS?

A. While the issues with cost shifting and misalignment between cost causation and cost recovery also exist for non-residential NEM customers, as a first step
I focus on rates for future residential NEM customers. Residential customers represent the vast majority of NorthWestern’s NEM customers today. Based on the historical trend, it is reasonable to expect that most new NEM customers in the future will also be residential.

Q. PLEASE SUMMARIZE THE KEY ARGUMENTS IN YOUR TESTIMONY.

A. In my testimony, I elaborate on the following points:

- The proposal to create a separate rate class is reasonable and justified.
- There is quantitative evidence that NEM customers differ from non-NEM customers along observable characteristics, especially patterns of energy consumption.
- Differences in customer load shapes create cost shifts and cross-subsidies between NEM and non-NEM customers under existing residential tariffs.
- The creation of a separate rate class and a class-specific revenue requirement would ameliorate these cost shifts.
- The establishment of a separate rate class for NEM customers is consistent with emerging practices in other jurisdictions to address these issues.
- The proposed three-part rate for NorthWestern’s future NEM customers is consistent with well-established principles for sound rate design, including economic efficiency, equity, revenue adequacy and stability, bill stability, and customer satisfaction.
- Support for three-part rates is found throughout the industry-accepted literature on rate design.
- Three-part rates are a proven concept and have been offered to commercial and industrial customers across the U.S. for decades, as well as residential customers in several states.
Empirical evidence and reason suggest that customers can understand the concept of kW demand and should be able to understand the concept of demand charges. Thus, I would expect customers to respond to three-part rates by modifying their electricity consumption patterns in economically beneficial ways.

Demand charges also promote the adoption of beneficial energy technologies like smart thermostats and batteries.

NorthWestern’s proposed basic service fee of $5.60/month is within the range of those observed by other utilities in Montana and across the Northwest U.S.

**I.C.** Brief Summary of the Residential Rate Proposal

**Q. WHAT IS NORTHWESTERN’S CURRENT RATE DESIGN?**

**A.** NorthWestern currently offers its residential customers a “two-part rate” through Schedules REDS-1 (Residential Electric Delivery Service) and ESS-1 (Electricity Supply Service). Together these Schedules comprise a two-part rate, because it consists of two types of charges: a basic service fee, which is a fixed charge per customer ($/month), and a volumetric charge which is based on the amount of electricity the customer has consumed (cents/kWh).

The residential rate charges are summarized in Table 1.
Table 1: NorthWestern’s Current Residential Rates (as of September 2018)

<table>
<thead>
<tr>
<th>Charge</th>
<th>Units</th>
<th>Value</th>
<th>Schedule</th>
</tr>
</thead>
<tbody>
<tr>
<td>Basic Service Charge</td>
<td>$/month</td>
<td>4.10</td>
<td>REDS-1</td>
</tr>
<tr>
<td>Energy Charge</td>
<td>$/kWh</td>
<td>0.109475</td>
<td></td>
</tr>
<tr>
<td>Supply</td>
<td>$/kWh</td>
<td>0.067314</td>
<td>ESS-1</td>
</tr>
<tr>
<td>Transmission</td>
<td>$/kWh</td>
<td>0.009822</td>
<td>ESS-1</td>
</tr>
<tr>
<td>Distribution</td>
<td>$/kWh</td>
<td>0.032339</td>
<td>REDS-1</td>
</tr>
<tr>
<td>Other Applicable Charges</td>
<td>$/kWh</td>
<td>0.002271</td>
<td></td>
</tr>
<tr>
<td>Supply Deferred Costs</td>
<td>$/kWh</td>
<td>0.000004</td>
<td>ESS-1</td>
</tr>
<tr>
<td>BPA Exchange Credit</td>
<td>$/kWh</td>
<td>-0.002249</td>
<td>REDS-1</td>
</tr>
<tr>
<td>CTC-QF</td>
<td>$/kWh</td>
<td>0.003182</td>
<td>CTC-QF-1</td>
</tr>
<tr>
<td>USBC</td>
<td>$/kWh</td>
<td>0.001334</td>
<td>E-USBC-1</td>
</tr>
</tbody>
</table>

Q. WHAT CHANGES ARE YOU PROPOSING TO NORTHWESTERN'S RATE DESIGN IN THIS PROCEEDING?

A. I propose the following changes to the current rate design:

1. The creation of a separate rate class for future residential NEM customers;

2. Transitioning to a mandatory “three-part” rate for residential NEM customers served under the separate rate class. The three-part rate consists of a fixed charge, a demand charge and an energy charge.

In addition, I provide support for NorthWestern’s proposal to increase the basic service fee in Schedule REDS-1.

Q. WHAT WOULD THE CREATION OF A SEPARATE RATE CLASS FOR RESIDENTIAL NEM CUSTOMERS ENTAIL?
A. I propose to create a separate rate class for future residential NEM customers. Such a class would have an allocated revenue requirement that is separate from that of other residential and non-residential rate classes.

Q. WHAT IS THE MANDATORY THREE-PART RATE THAT YOU PROPOSE FOR FUTURE RESIDENTIAL NEM CUSTOMERS?

A. I propose a three-part rate for future residential NEM customers. The rate is designed to better reflect the cost of serving NEM customers, and is based specifically on an embedded cost of service (ECOS) study conducted for all NorthWestern rate classes, as described in the Prefiled Direct Testimony of Paul M. Normand (Normand Direct Testimony). The proposed rate is summarized in Table 2; for details on the calculations underlying the proposed rate, see Appendix G.

Table 2: Proposed Three-Part Rate Design for Future NEM Customers

<table>
<thead>
<tr>
<th>Charge</th>
<th>Units</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Basic Service Charge</td>
<td>$/month</td>
<td>5.60</td>
</tr>
<tr>
<td>Energy Charge</td>
<td>$/kWh</td>
<td>0.065698</td>
</tr>
<tr>
<td>Supply</td>
<td>$/kWh</td>
<td>0.065698</td>
</tr>
<tr>
<td>Demand Charge</td>
<td>$/kW</td>
<td>8.64</td>
</tr>
<tr>
<td>Transmission</td>
<td>$/kW</td>
<td>1.40</td>
</tr>
<tr>
<td>Distribution</td>
<td>$/kW</td>
<td>7.24</td>
</tr>
<tr>
<td>Other Applicable Charges</td>
<td>$/kWh</td>
<td>0.002271</td>
</tr>
</tbody>
</table>

Q. WHAT IS NORTHWESTERN’S PROPOSAL REGARDING THE CUSTOMER CHARGE IN ITS RESIDENTIAL RATES?
A. NorthWestern is proposing to increase the basic service fee to $5.60 per month in both the residential non-NEM and the proposed residential NEM rate classes.³ This increase is intended to bring fixed revenues closer to recovering NorthWestern’s fixed costs of serving residential customers. The proposed customer charge does not fully reflect the fixed per-customer costs identified in Normand Direct Testimony, which are estimated to be around $10/month for residential NEM and non-NEM customers, but it makes a step in the right direction. The proposed increase in the fixed charge proportionally shifts the collection of revenues from the volumetric charge to the fixed charge, but does not increase the overall amount of revenue collected.

II. JUSTIFICATION FOR THE CREATION OF A SEPARATE RATE CLASS FOR NEM CUSTOMERS

Q. IS THERE A PROBLEM WITH HAVING NEM AND NON-NEM CUSTOMERS IN THE SAME RATE CLASS?

A. Yes. NEM customers rely heavily on the power grid. When the sun is not shining or the wind is not blowing, they are drawing power from the grid, like other customers. And when the sun is shining or the wind is blowing, and NEM customers’ power generation exceeds their power consumption, they will be exporting power to the grid, unlike non-NEM customers. In other words, they have a bi-directional relationship with the grid.

³ Here and in future discussion, when referring to the residential non-NEM class, I also include current NEM customers who would be grandfathered into the non-NEM rate class.
However, as residential NEM and non-NEM customers are currently in the same rate class, they pay the same rates under the same tariff. This current rate over-compensates NEM customers for the power they sell to the grid.\textsuperscript{4} The over-compensation occurs because the residential rate at which NEM customers are compensated includes not only the variable costs of electricity, which the NEM customers are selling to NorthWestern, but also costs associated with the transmission and distribution grid, as well as generation capacity costs and fixed costs of customer service, none of which NEM customers are selling to NorthWestern. Furthermore, it does not reflect additional costs that NEM customers may impose on the system because of their two-way interaction with the grid.

This over-compensation to NEM customers is then recovered from non-NEM customers to ensure that the utility recovers its revenue requirement. Thus, non-NEM customers end up paying a higher rate than they would otherwise be paying. This results in an unintended cross-subsidy from non-NEM customers (including, in most jurisdictions, a disproportionately large share of lower income customers) to NEM customers. That cross-subsidy largely remains invisible to the non-NEM customers.

\textsuperscript{4} NEM customers are not directly paid for their energy. Instead, any excess generation offsets consumption in the same month; if there is remaining net excess generation at the end of the month, customers receive a bill credit (in kWh terms) to be used in subsequent months. As a result, the effective rate NEM customers are credited for their generation equals their volumetric energy rate. The sole exception occurs when NEM customers generate more than they consume over the course of a 12-month billing period; in this case, net excess generation at the end of this period is forfeited and customers do not receive a credit going into the following year.
Q. CAN THIS CROSS-SUBSIDY BE ELIMINATED?

A. Yes. This cost-shift can be ameliorated through the creation of a separate class of NEM customers. These customers would be offered rates based on their cost of service. Doing so would ensure that NEM customers will pay their fair share of electricity costs while still being fairly compensated for the electricity they generate from their solar panels. Since residential NEM customers have very different load characteristics than non-NEM customers, it is appropriate to consider them a separate class of customers with their own unique rate.

The problem with NorthWestern’s current rate offering, and a description of how this problem can be addressed through the introduction of a separate, cost-based rate for NEM customers, is provided in Figure 1.

Figure 1: How a Separate NEM Rate Corrects the Problem in NorthWestern’s Existing Rate Offering

The result is an invisible, unintended subsidy from non-NEM customers to NEM customers.
In the following sub-sections, I will elaborate on a number of points about my proposal to create a separate rate class for residential NEM customers. These include:

- There is empirical evidence that NEM customer load shapes differ significantly from that of the typical residential customer in Montana. NEM load shapes also differ significantly from those of customers who participate in energy efficiency programs.

- These differences in load shapes lead to a significant and disproportionate shift in the recovery of power system infrastructure costs from NEM customers to non-NEM customers.

- Low-income customers are disproportionately and negatively impacted by the cost shift.

- While NEM adoption levels in Montana are modest, they are growing fast, as they are in the rest of the country. Thus, it is important to create a new rate class for NEM customers now.

- There is precedent for creating a separate rate class for NEM customers. This has been introduced in Arizona, Idaho, and Kansas. Many states continue to grapple with the challenges presented by net metering with volumetric rates.

II.A. NEM CUSTOMER LOAD SHAPES ARE SIGNIFICANTLY DIFFERENT THAN THOSE OF NON-NEM CUSTOMERS

Q. DOES THE HOURLY LOAD SHAPE OF NORTHWESTERN’S CURRENT NEM CUSTOMERS DIFFER SIGNIFICANTLY FROM THAT OF NON-NEM CUSTOMERS?

A. Yes. I have conducted empirical analysis with data on NorthWestern customers which finds that the differences are quite significant.
Q. WHAT DATA DID YOU USE TO ANALYZE THE LOAD SHAPES OF NEM AND NON-NEM CUSTOMERS?

A. NorthWestern provided me with 15-minute interval load data for a sample of residential NEM and non-NEM customers. The NEM data begin in January 2016 and run through June 2018. This dataset includes a sample of 49 net metering customers who installed distributed energy before 2016. The data include the date of installation of rooftop PV and reflect the net load of the NEM customers, including exports to the grid. The non-NEM customer dataset is from NorthWestern’s load research sample, and begins in July 2017 and runs through June 2018. These data include 180 customers who have not installed distributed energy resources.

Q. DO YOU BELIEVE THE NEM CUSTOMER SAMPLE IS APPROPRIATE AND REPRESENTATIVE OF THE NEM CLASS?

A. Yes. This sample was chosen through stratified random sampling, a method that divides the population into smaller groups known as “strata.” In this case, NorthWestern divided the NEM customers into strata based on the capacity of their distributed generation installation. Within each strata, NorthWestern randomly selected between 3 and 24 NEM customers to include in the NEM sample (depending on the total number of NEM customers in each stratum).

Based on my experience in working with similar data in the past, this

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5 NorthWestern currently has 1,823 residential NEM customers. Interval load data is available for 49 of them. See Appendix F for more details on the NEM customer characteristics and the NEM load interval data.
The sampling methodology and sample size is appropriate for representing the NEM class. The methodology is very similar to that used by NorthWestern and utilities around the country to select their load research samples.

The sample of 49 customers includes 48 customers with distributed solar generation and one customer with wind generation. No customers with hydro or other distributed generation were included in the sample. This reflects the broader population of NEM customers, which is almost entirely comprised of customers with solar generation.

**Q. WHAT WAS YOUR METHODOLOGICAL APPROACH TO ANALYZING THE NEM CUSTOMER LOAD SHAPES?**

**A.** I compared the average load profiles of NEM customers to those of non-NEM customers in NorthWestern’s load research sample. This provides perspective on how NEM customer load profiles differ from the typical residential customer. I included all customers in the NEM interval load data, including the customer with wind generation. I did not separately analyze the load profiles of customers with solar, wind, or other generation. I determined such analysis was not necessary to establish overall patterns in consumption by NEM customers, and such an analysis was not requested by NorthWestern.
Q. WHAT DID YOU FIND IN YOUR ANALYSIS OF NEM CUSTOMER LOAD SHAPES?

A. The net load shapes of residential NEM customers are significantly different than those of non-NEM customers. Figure 2 summarizes the comparison of average load profiles for non-NEM customers relative to NEM customers. The load shapes are dramatically different for both types of customers, especially during summer months.
Quantitatively, the average annual net energy consumption of NEM customers (after they have installed distributed generation) was 24 percent lower than that of non-NEM customers. In contrast, those customers’ average monthly maximum demand was higher by 16 percent. In other words, while
the NEM customers reduce their total energy needs, their heavy reliance on grid infrastructure persists. Table 3 summarizes results of the analysis.

**Table 3: Load Characteristics of NEM and Non-NEM Customers**

<table>
<thead>
<tr>
<th></th>
<th>Units</th>
<th>April</th>
<th>August</th>
<th>December</th>
<th>Monthly Avg.</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Net Energy Consumption</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Non-NEM Customer</td>
<td>kWh</td>
<td>699</td>
<td>735</td>
<td>1,016</td>
<td>769</td>
</tr>
<tr>
<td>NEM Customer</td>
<td>kWh</td>
<td>392</td>
<td>94</td>
<td>1,496</td>
<td>581</td>
</tr>
<tr>
<td>% Difference</td>
<td>%</td>
<td>-44%</td>
<td>-87%</td>
<td>47%</td>
<td>-24%</td>
</tr>
<tr>
<td><strong>Max Demand</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Non-NEM Customer</td>
<td>kW</td>
<td>4.8</td>
<td>5.1</td>
<td>5.4</td>
<td>5.0</td>
</tr>
<tr>
<td>NEM Customer</td>
<td>kW</td>
<td>5.8</td>
<td>5.2</td>
<td>7.1</td>
<td>5.8</td>
</tr>
<tr>
<td>% Difference</td>
<td>%</td>
<td>20%</td>
<td>4%</td>
<td>31%</td>
<td>16%</td>
</tr>
<tr>
<td><strong>Load Factor</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Non-NEM Customer</td>
<td>%</td>
<td>20%</td>
<td>20%</td>
<td>25%</td>
<td>21%</td>
</tr>
<tr>
<td>NEM Customer</td>
<td>%</td>
<td>9%</td>
<td>2%</td>
<td>29%</td>
<td>13%</td>
</tr>
<tr>
<td>% Difference</td>
<td>%</td>
<td>-54%</td>
<td>-87%</td>
<td>14%</td>
<td>-40%</td>
</tr>
</tbody>
</table>

*Source:* Brattle analysis of NorthWestern’s interval data.

**Q.** DID YOU ALSO ANALYZE THE PATTERNS OF NET EXPORTS BY NEM CUSTOMERS?

**A.** Yes, I did. I found that approximately 97 percent of NEM customers rely on the grid to accept excess generation. NEM customers export on average 268 kWh per month, even though this number varies significantly across customers and seasons. For instance, in April, August, and December NEM customers export on average to the grid 314 kWh, 451 kWh, and 37 kWh respectively. I found that NEM customers’ monthly maximum export is 2.8 kW, and on average, 17 percent of NEM customers have a higher maximum exports than maximum consumption demand across all months.
Q. WHAT DO YOU CONCLUDE FROM YOUR ANALYSIS OF NEM CUSTOMER LOAD SHAPES?

A. The NEM customer load profile is significantly different than that of the typical residential customer. There is a common misperception that, by virtue of generating their own electricity, NEM customers rely on the power grid significantly less than non-NEM customers. In fact, while a customer reduces his/her total (kWh) energy needs by installing a rooftop PV system, the customer’s requirement for grid infrastructure is largely unchanged due to minimal changes in their peak demand (kW).

Additionally, NEM customers engage in a two-way transaction with the grid, which imposes further costs. They still consume a significant amount of electricity during hours when the sun is not shining, and when the sun is shining, NEM customers may be exporting power to the grid. As a result, NEM customers place a significant demand during those system peak hours that drive the need for investments in infrastructure that are necessary to maintain a sufficient level of reliability.

II.B. THE NEM COST SHIFT IS REAL AND SHOULD BE ADDRESSED

Q. IS THERE A COST-SHIFT BETWEEN NEM AND NON-NEM CUSTOMERS?

A. Yes. As I discussed previously, the unique load characteristics of NEM customers combined with net metering under a flat volumetric rate
disproportionately shifts the recovery of NorthWestern’s costs from NEM customers to non-NEM customers.

The magnitude of this unintended cross-subsidy will depend on a number of factors, such as the number of customers adopting PV, the average size of PV installation, and the rate structure and level. A survey of studies in other jurisdictions designed to quantify the magnitude of this cost shift found that it could amount to between approximately $400 and $1,800 per NEM customer per year. This is summarized in Figure 3.

Two of the estimates included in Figure 3 are specific to NorthWestern’s service territory. The first, of $464 per customer per year, is derived from the NEM benefit-cost analysis prepared by Navigant for NorthWestern Energy (Montana) in March 2018. The second, of $402 per customer per year, is derived from the findings of the ECOS in the Normand Direct Testimony.

I would expect the estimates of the cross-subsidy in NorthWestern’s territory to fall at the lower end of the range seen in other jurisdictions. NorthWestern’s volumetric energy rates are somewhat lower than those seen in other jurisdictions, and the solar potential in Montana is also lower than in

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

other states; both contribute to a somewhat lower cost-shift. However, there is little doubt that such a subsidy exists under the current rate structure.

Figure 3: NEM Cost-Shift Estimates ($ per NEM customer per year)

Notes: Year indicates date of cost-shift estimate, which is sometimes a forecast. In some cases, reported estimates were converted to annual dollars per NEM customer for comparison purposes. NWE (ECOS Estimate) is the difference between allocated costs and revenues under existing rate from Normand Direct Testimony ECOS. NWE (Navigant) cost-shift estimate from Navigant’s “Net Energy Metering (NEM) Benefit-Cost Analysis” report prepared for NorthWestern Energy – Montana, for medium adoption forecast and no CO₂ pricing; cost-shift estimate in $/kWh of generation was multiplied by Brattle’s estimate for annual solar output of average NEM residential customer. The PG&E ranges are calculated using assumptions from the California Public Utilities Commission's Public Modeling Tool. PPC and NPC refer to Sierra Pacific Power Company and Nevada Power Company service territories respectively.

Q. WHAT IS THE RELATIONSHIP BETWEEN THE NAVIGANT STUDY, THE ECOS STUDY, AND YOUR TESTIMONY?

A. Both the Navigant study and the ECOS study in the Normand Direct Testimony provide estimates of the cost shift between NEM customers and other customers, but from different perspectives. The Navigant study provides
economic analysis of the benefits and costs of rooftop solar photovoltaic (PV) with NEM in Montana. This study was forward-looking, developing costs and benefits over a 25-year period between 2018 and 2042 across multiple solar adoption scenarios. It quantified benefits of rooftop solar PV with NEM, including avoided energy costs, generation capacity costs, transmission and distribution capacity costs, and system losses, among others. These benefits were compared to costs of rooftop solar PV with NEM, including reduced revenues, administrative costs, interconnection costs, and integration costs. This analysis found that the costs of rooftop solar PV with NEM are larger than the benefits, in dollars per kWh of solar generation under the rate-payer impact test. This implies a substantial cost shift on a per-NEM-customer basis.

Similar to the Navigant findings that the forward-looking benefits of rooftop solar PV with NEM are negative on net, Normand Direct Testimony provides evidence that allocated costs in 2017 were substantially larger than revenues collected for residential NEM customers. Furthermore, my testimony presents quantitative and qualitative evidence that residential NEM customers are substantially different than non-NEM customers, and provides a holistic argument for the creation of a separate rate class.

Q. IN GENERAL, DO LOW INCOME CUSTOMERS BEAR A DISPROPORTIONATE SHARE OF THE COST-SHIFT BURDEN?

A. Yes. In general, research supports the observation that low income customers are subject to a disproportionate share of the cost shift burden. Publicly
available studies by E3\textsuperscript{8} (for the California Public Utilities Commission), Dr. Severin Borenstein\textsuperscript{9} (a professor at UC Berkeley), and Solar Pulse\textsuperscript{10} (a solar market research firm which pairs customers with rooftop PV installers) have all shown empirically that lower income customers have been less likely to install rooftop PV than higher income customers. Table 4 summarizes the conclusions of each study.

Table 4: The Relationship between Household Income and Rooftop PV Adoption

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

Q. SHOULD THE COST-SHIFT BE IGNORED DUE TO THE MODEST NUMBER OF RESIDENTIAL CUSTOMERS WHO CURRENTLY HAVE NEM IN MONTANA?

A. No. There are significant benefits to correcting the NEM rate design before rooftop PV is adopted in larger numbers. At limited levels of adoption it is easier to address issues such as grandfathering of existing NEM customers into the current NEM rates policy. The impacts of grandfathering on customers - and the contentiousness of the issue - grow as more customers adopt rooftop PV. The same also applies to customer education. It is easier to educate customers about their rate options when the vast majority are in a similar situation rather than when they have become bifurcated.
The current level of PV adoption should not influence the Montana Public Service Commission’s decision in reforming NEM rates. While the market penetration of rooftop solar may currently be modest in NorthWestern’s Montana service territory, the rooftop solar industry is a newly emerging industry. In fact, SolarCity (a well-known, established national rooftop solar developer) was acquired in 2016 by Tesla at a price tag of $2.6 billion.\textsuperscript{11} Rooftop PV costs have come down significantly over the last several years, and the solar industry has grown at the same time. Additionally, the number of NEM installations in NorthWestern’s service area has increased by more than 100 percent over the past five years. Finally, modeling by the National Renewable Energy Laboratory (NREL) and Navigant forecasts strong and sustained growth of solar adoption within NorthWestern’s Montana service territory over the coming decades.\textsuperscript{12}

II.C. EXPERIENCES IN OTHER JURISDICTIONS ESTABLISHING A SEPARATE RATE CLASS FOR NEM CUSTOMERS

Q. HAVE UTILITIES AND REGULATORY COMMISSIONS IN OTHER JURISDICTIONS ESTABLISHED A SEPARATE RATE CLASS FOR NEM CUSTOMERS IN ORDER TO ADDRESS THE VARIOUS COST SHIFT ISSUES DESCRIBED IN YOUR TESTIMONY?

\textsuperscript{11} Robert Farris, “Tesla and SolarCity merger gets approval from shareholders,” CNBC (November 2016), accessed January 10, 2018.

\textsuperscript{12} The NREL adoptions forecasts were adjusted downwards in the Navigant study of NEM costs and benefits, but both forecasts reflect significant increases in solar adoption. For further discussion of both forecasts, see Navigant, “Net Energy Metering (NEM) Benefit-Cost Analysis,” Prepared for NorthWestern Energy – Montana, March 29, 2018.
A. Yes, I am aware of three notable cases: Salt River Project (SRP) in Arizona, the Kansas Corporation Commission (KCC), and the Idaho Public Utilities Commission (IPUC).

Q. PLEASE DESCRIBE THE ACTIVITY BY SRP.

A. In 2014, SRP developed a proposal to create a separate rate class for NEM customers.\(^\text{13}\) SRP’s governing Board of Directors approved the proposal in 2015.\(^\text{14}\) In doing so, a three-part rate with a demand charge became the standard rate for all of SRP’s future residential NEM customers. Existing NEM customers were grandfathered under the pre-existing rate structure.

Q. PLEASE DESCRIBE HOW THE NEM COST SHIFT ISSUES WERE ADDRESSED IN KANSAS.

A. In 2016, the KCC opened a regulatory docket to explore the possibility of creating a separate rate class for NEM customers.\(^\text{15}\) After reviewing filings by Westar Energy and various intervenor groups, the KCC issued an Order in 2017 confirming that NEM customers should be treated as a separate rate


class with its own revenue requirement. The KCC cited the significantly different load and cost characteristics between NEM and non-NEM customers as reasons for its decision.

Q. PLEASE DESCRIBE THE ACTIVITY IN IDAHO.

A. In 2017, Idaho Power Company (IPC) applied before the Idaho Public Utilities Commission for authority to establish new rate schedules for residential and small general service NEM customers. The Commission reviewed filings from IPC and intervenors and held a technical hearing and public hearings for customers. In 2018, the Commission issued an order allowing for the creation of separate rate classes, stating “based on the evidence before us, we find it is time to distinguish a class of customers that uses the grid for standard energy import and use, from a class of customers that uses the grid to both import and export energy [...] Evidence of cost shifting, or subsidization, and load and usage characteristics informed our decision.”

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Q. HAVE OTHER JURISDICTIONS MADE SIMILAR DECISIONS TO ADDRESS COST SHIFT ISSUES THROUGH SPECIFIC RATE TREATMENT FOR NEM CUSTOMERS?

A. Yes. In California, the California Public Utilities Commission (CPUC) elected to make time-of-use rates the mandatory rate offering for residential NEM customers. Unlike other residential customers, NEM customers will not have the option to enroll in a flat rate.

In Arizona, Arizona Public Service (APS) and intervenors reached a settlement agreement which established that residential NEM customers could choose either (1) a three-part rate or (2) a two-part rate with a time-of-use volumetric charge and a “grid access charge.” NEM customers do not have access to the flat rate option that is offered to other residential customers.

Q. ARE THERE OTHER NOTABLE CASES OF REGULATORY COMMISSIONS ADDRESSING THE NEM COST SHIFT CHALLENGES?

A. Yes. In Hawaii in 2015, the Hawaii PUC ended the state’s net energy metering policy and replaced it with two other options. The first was the

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20 Hawaii Public Utilities Commission, Decision and Order Resolving Phase 1, Docket No. 2014-0192; Order No. 33258, October 12, 2015.
“self-supply” option in which NEM customers can net their NEM output against their electricity consumption, but are not compensated for net exports to the grid. The second was the “grid-supply” option, in which all output from the PV system is compensated at a level below the retail electricity price. Since then, the Hawaii PUC has approved additional customer renewable programs to replace net metering. Primarily, in October 2017, the Hawaii PUC approved the “smart export” program for customers installing rooftop PV and energy storage systems, and the “controllable CGS” program as a successor to the “grid supply” program.21

Additionally, many utilities have pursued rate changes for all customers, such as increasing the monthly customer charge.22

Q. WHAT DO YOU CONCLUDE FROM YOUR REVIEW OF THE EXPERIENCE IN OTHER JURSDICTIONS?

A. Utilities and regulatory commissions increasingly understand the importance of addressing the challenges associated with the NEM cost shift. A variety of approaches have been taken, and the creation of a separate rate class for NEM


customers is one such approach with precedent in other jurisdictions. In this regard, my proposal is consistent with experience elsewhere.

III. PRINCIPLES OF RATE DESIGN

Q. IS THERE SUPPORT FOR THREE-PART RATES IN THE LITERATURE ON RATE DESIGN?

A. Yes. The principles that guide rate design and support the deployment of three-part rates have evolved over time. Many authorities have contributed to their development, beginning with the legendary British rate engineer John Hopkinson in the late 1800s.\textsuperscript{23} Hopkinson introduced demand charges into electricity rates. Not long after, Henry L. Doherty proposed a three-part tariff, consisting of a fixed service charge, a demand charge and an energy charge.\textsuperscript{24} The demand charge was based on the maximum level of demand which occurred during the billing period. Some versions of the three-part tariff also feature seasonal or time-of-use variation corresponding to the variations in the costs of energy supply.\textsuperscript{25}

In the decades that followed, a number of British, French and U.S. economists and engineers made further enhancements to the original three-


\textsuperscript{24} Henry L. Doherty, Equitable, Uniform and Competitive Rates, Proceedings of the National Electric Light Association (1900), pp.291-321.

part rate design. In 1961, Professor James C. Bonbright coalesced their thinking in his canon, Principles of Public Utility Rates, whose expanded second edition is co-authored with Albert Danielsen and David Kamerschen. Some of these ideas were further expanded upon by Professor Alfred Kahn in his treatise, The Economics of Regulation.

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

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

Q. WHAT IS THE PRINCIPLE OF ECONOMIC EFFICIENCY?

A. The price of electricity should convey to the customer the cost of providing it, ensuring that resources consumed in the production and delivery of electricity are not wasted. If the price is set equal to the cost of providing a kWh,

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customers who value the kWh more than the cost of producing it will use the kWh and customers who value the kWh less will not. This will encourage the development and adoption of energy technologies that are capable of providing the most valuable services to the power grid, and thus the greatest benefit to electric customers as a whole.

**Q. WHAT IS THE PRINCIPLE OF EQUITY?**

**A.** There should be no unintentional subsidies between customer types. A classic example of the violation of this principle occurs under flat rate pricing structures (i.e., cents/kWh). Since customers have different load profiles, “peaky” customers, who use more electricity when it is most expensive, are subsidized by less “peaky” customers who overpay for cheaper off-peak electricity. Note that equity is not the same as social justice, which is related to inequities in socioeconomic status rather than cost. The pursuit of one is not necessarily the pursuit of the other, and vice versa.

**Q. WHAT IS THE PRINCIPLE OF BILL STABILITY?**

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

Q. **WHAT IS THE PRINCIPLE OF CUSTOMER SATISFACTION?**

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

Q. **WHAT IS THE PRINCIPLE OF REVENUE ADEQUACY AND STABILITY?**

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

Q. **IS THERE AN OVERRIDING PRINCIPLE THAT SHOULD GUIDE RATE DESIGN DECISIONS?**

A. Yes. The overriding principle in rate design is that of cost-causation. In other words, the rate structure should reflect the underlying cost structure. The importance of economic efficiency – and specifically on designing rates that
reflect costs – is emphasized by Bonbright. In the first edition of his text, Bonbright devotes an entire chapter to cost causation. In the chapter, he states:

“One standard of reasonable rates can fairly be said to outrank all others in the importance attached to it by experts and public opinion alike – the standard of cost of service, often qualified by the stipulation that the relevant cost is necessary cost or cost reasonably or prudently incurred.”

Later, he states “The first support for the cost-price standard is concerned with the consumer-rationing function when performed under the principle of consumer sovereignty.” Bonbright also cites another benefit of the cost-price standard, saying that “an individual with a given income who decides to draw upon the producer, and hence on society, for a supply of public utility services should be made to ‘account’ for this draft by the surrender of a cost-equivalent opportunity to use his cash income for the purchase of other things.”

IV. SUPPORT FOR THE PROPOSED THREE-PART RATE FOR FUTURE NEM CUSTOMERS

Q. IS YOUR PROPOSAL TO INTRODUCE A THREE-PART RATE CONSISTENT WITH THE ACCEPTED PRINCIPLES OF RATE DESIGN?

A. Yes. The introduction of a three-part rate for residential NEM customers is consistent with the previously discussed principles of rate design. My


proposal further improves the alignment of its rate design with these principles.

Q. HOW DOES YOUR PROPOSAL SATISFY THE PRINCIPLE OF ECONOMIC EFFICIENCY?

A. The cost-based price signals in the three-part rates I propose provide customers with the financial incentive to make investments in technologies or otherwise change their behavior in ways that are most beneficial to the system. Technologies and behaviors that reduce a customer’s peak demand should ultimately lead to a more efficient use of the grid, reduced system costs, and bill savings.

Q. HOW DOES YOUR PROPOSAL SATISFY THE PRINCIPLE OF EQUITY?

A. Each customer imposes costs on the system, some of which are fixed and the rest of which are demand-driven and energy-driven. Under purely volumetric tariffs, customers with high demand but low monthly consumption would not be paying their fair share of the cost of maintaining, upgrading, and expanding the utility’s generation, transmission and distribution system. Instead, lower-demand customers would be covering the deficit and paying more than their fair share. The proposed three-part rates more closely match demand, fixed, and variable costs with demand, fixed, and variable charges and will reduce this inequity so that all customers will pay their fair share of the costs
Q. HOW DOES YOUR PROPOSAL SATISFY THE PRINCIPLE OF BILL STABILITY?

A. NorthWestern’s current rates recover significant amounts of fixed costs through volumetric charges. The result is an overstated volumetric charge. This subjects a disproportionate amount of a customer’s bill to month-to-month fluctuations in usage, and as a result, bills are more variable and unpredictable than they would be if the rates were designed more appropriately. In a variable climate like Montana’s, this can result in high seasonal bills relative to other times of the year.

Fluctuations in a customer’s bill can be measured using metrics known as the “coefficient of variation” and the “standard deviation” of bills. Standard deviation measures how significantly a customer’s individual monthly bills differ from their average bill over the course of the year and across years. The coefficient of variation is the standard deviation divided by the average bill, and reflects the volatility of bills as a percent of the average bill. I calculated customer-specific bill volatility under the current rate and proposed three-part rate. I found that the proposed three-part rate would substantially reduce the volatility in customer bills. The results of this analysis are summarized in Table 5.
Table 5: Volatility of NEM Customer Bills under Current and Proposed Rate

<table>
<thead>
<tr>
<th></th>
<th>Avg. Standard Deviation</th>
<th>Avg. Coefficient of Variation</th>
</tr>
</thead>
<tbody>
<tr>
<td>Current two-part rate</td>
<td>$53</td>
<td>84%</td>
</tr>
<tr>
<td>Proposed three-part rate</td>
<td>$44</td>
<td>45%</td>
</tr>
</tbody>
</table>

Notes: I calculated the mean and the standard deviation of monthly bills for each customer and took the weighted average based on each customer’s weight in the sample. The target revenues for the proposed three-part rate are higher than for the current two-part rate. However, the coefficient of variation divides the standard deviation by the mean bill to make the results comparable.

Q. HOW DOES YOUR PROPOSAL SATISFY THE PRINCIPLE OF CUSTOMER SATISFACTION?

A. I believe residential NEM customers are likely to find the three-part rate design more attractive than other rate designs that would be necessary to recover costs from the residential NEM customer segment such as significantly increasing the basic service fee. With a three-part rate, customers have the ability to reduce their bills by managing their electricity demand; it provides them with an option that other rate designs do not.

From a customer standpoint, the three-part rate strikes a reasonable balance between cost-reflectivity and simplicity. A “pure” cost-based rate would require multiple demand charges (based on the timing of transmission and distribution system peaks), sub-hourly volumetric rates to capture fluctuations in marginal energy costs, and possibly location-specific variation. The proposed three-part rate is a simplification of such a design, and should be easier for customers to understand and respond to.
Q. CAN CUSTOMERS RESPOND TO THE PRICE SIGNALS IN THREE-PART RATES?

A. Yes. There is a widespread misperception that customers do not respond to changing electricity prices. This misperception is contradicted by empirical evidence derived from more than 60 pilots and full-scale rate deployments involving over 300 innovative rate offerings over roughly the past two decades. The pilots have found that customers can and do respond to new price signals by changing their consumption pattern.\(^{32}\)

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


\(^{32}\) Some of these studies are summarized in Ahmad Faruqui, Sanem Sergici, and Cody Warner, “Arcturus 2.0: A meta-analysis of time-varying rates for electricity,” The Electricity Journal, 2017. Similar results were obtained from an earlier generation of 14 pricing pilots that were funded in the late 1970’s and early 1980’s by the U.S. Federal Energy Administration (later part of the Department of Energy). See Ahmad Faruqui and Bob Malko, “The Residential Demand for Electricity by Time-of-Use: A Survey of Twelve Experiments with Peak Load Pricing,” Energy, Vol. 8, No. 10, (1983).

APS has also examined the experience of the customers on its highly subscribed optional three-part rate and detected a significant level of price response. Specifically, 60 percent of a sample of APS’s customers on a three-part rate reduced their demand after switching to the three-part rate, with those who actively manage their demand achieving demand savings of 9 percent to 20 percent or more.\(^{33}\)

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

Q. HOW DOES YOUR PROPOSAL SATISFY THE PRINCIPLE OF REVENUE ADEQUACY AND STABILITY?

A. The proposed rates will more accurately collect revenue from those customers who are imposing costs on the power system. In addition, aligning customer’s bills with their cost causation sends more efficient price signals. Over time, this should decrease underlying costs and decrease revenue requirements as it incentivizes conservation when such actions are most beneficial.

It is worth noting that, while Professor Bonbright says that rates should be stable and predictable, he does not say that rate structures should remain frozen in time. In the U.S., there is an ineluctable movement towards cost-reflective rates brought about by the rollout of advanced metering infrastructure (AMI) and by the increased availability and customer adoption of a wide range of digital end-use technologies such as smart appliances, smart thermostats, home energy management systems, battery storage systems, electric vehicles and rooftop solar panels. My three-part rate proposal is designed to provide stability in this new environment.

Q. IS THERE REGULATORY PRECEDENT FOR OFFERING THREE-PART RATES IN MONTANA?

A. Yes, there is extensive industry experience with three-part rates. They have been offered to commercial and industrial (C&I) customers for decades, and are the norm for these customer classes. In Montana, demand charges are offered by all major utilities.\(^34\) In fact, all of these utilities offer three-part rates to at least a portion of the C&I customers on a mandatory basis.\(^35\) Eight of the utilities offer demand charges on a mandatory basis to even the smallest commercial and industrial customer segment.

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\(^{34}\) For relevance, I excluded small utilities serving less than 150 customers. There are 25 utilities in Montana above this size threshold. The list includes investor-owned utilities and cooperatives. I excluded from the list two cooperatives for which I could not find tariff sheets. See Appendix D for details.

\(^{35}\) This is also common practice at many utilities throughout the US.
Q. ARE THREE-PART RATES OFFERED TO RESIDENTIAL CUSTOMERS IN OTHER JURISDICTIONS?

A. Yes. Three-part rates are currently offered by utilities to residential customers, though on a more limited basis than for C&I customers. Their availability is increasing in part as technical barriers are removed through the deployment of AMI.

There are at least 50 utilities across 24 states offering a total of 60 different three-part rates to residential customers. Three of these utilities are in Montana: Lincoln Electric Cooperative, Sun River Electric Cooperative, and Vigilante Electric Cooperative. Arizona Public Service (APS) has the most highly subscribed residential three-part rate in the US, with nearly 120,000 of its customers voluntarily choosing to enroll. Similar to my proposal, Salt River Project (SRP) recently instituted a mandatory three-part rate for all residential customers who chose to install a new grid-connected distributed generation (NEM) photovoltaic system after January 1, 2015. SRP, “Customer Generation Price Plan.” http://www.srpnet.com/prices/home/customergenerated.aspx. Mid-Carolina Electric Cooperative (South Carolina) and Butler Rural Electric Cooperative (Kansas) include demand charges as a mandatory feature of their residential rate offerings to all customers. I provide a list of utilities offering

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36 My survey was conducted in September 2018. A list of utilities is provided in Appendix D.
37 Peak demand management could be another driver. Although many three-part rates are driven by distributed generation, it is not the only motivation behind the rate. In Maryland and Missouri where utilities’ ability to design rates specifically for distributed generation is restricted, the focus is on the demand management benefit.
residential three-part rates, and a review of the key design components of those rates, in Appendix C.

Q. HOW DO YOU RECOMMEND MEASURING CUSTOMERS’ PEAK DEMAND IN THE PROPOSED NEM RATE?

A. I propose to measure customers’ monthly peak as the maximum one-hour demand across all hours of the day.

Measurement across all hours of the day is consistent with using the demand charge to recover costs that are not driven by system peak conditions. As NorthWestern experiences a broad distribution of system peak hours across the year, the demand charge is not intended to align with the system peak, nor to recover costs that are driven by the system peak. Instead, the demand charge primarily recovers delivery costs, which tend to be driven by local load patterns, not by the system peak. The volumetric energy charge will recover generation costs, including both fixed and variable generation costs.

Measuring peak demand over a one-hour interval is a customer-friendly rate design feature that is well-suited to the residential class. A shorter interval, such as 15 or 30 minutes used for larger customers, would tend to yield a more volatile measure of demand, and therefore the potential for increased bill volatility.
IV.A. THE PROBLEM WITH A TWO-PART RATE FOR NEM CUSTOMERS

Q. COULD COSTS ALTERNATIVELY BE RECOVERED FROM FUTURE NEM CUSTOMERS THROUGH A TWO-PART RATE?

A. In theory, placing future NEM customers in a separate class with its own revenue requirement would allow sufficient recovery of costs from this class through a two-part rate. However, this approach would have several distinct disadvantages relative to the three-part rate.

Under this rate design, the basic service fee could be increased to recover delivery costs while maintaining a cost-reflective volumetric charge. Assuming the volumetric charge remains unchanged from its level in the proposed three-part rate, I have estimated that the customer charge in a two-part rate would need to increase roughly from the current $4.10 to approximately $56 per month in order to collect the revenues for residential NEM customers as proposed in this filing. Such a rate would not provide customers with a price signal to manage peak demand.

The three-part rate avoids the problems described above by more closely reflecting the structure of underlying cost drivers. It provides customers with an efficient signal to manage their energy demand in a way that will reduce system costs and, ultimately, customer bills.

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39 Further details on this alternative rate design provided in Appendix E.
V. INCREASING THE BASIC SERVICE FEE

Q. HAVE YOU REVIEWED NORTHWESTERN’S PROPOSAL TO INCREASE THE BASIC SERVICE FEE IN ITS RESIDENTIAL RATES?

A. Yes. NorthWestern has proposed to increase the basic service fee in its residential tariffs to $5.60/month. The basic service fee in the proposed NEM three-part rates is also $5.60/month.

My understanding is that the basic service fees are being increased in order to better align with NorthWestern’s customer costs. Based on my review of the ECOS study presented in the Normand Direct Testimony, the proposed basic service fees still would fall well shy of fully recovering NorthWestern’s fixed costs, but they are a small step in that direction.

Q. HOW DO NORTHWESTERN’S RESIDENTIAL BASIC SERVICE FEES COMPARE TO THOSE OF OTHER UTILITIES IN MONTANA?

A. I conducted a survey of the fixed charges in residential rates offered by all electric utilities in Montana for which I could find the necessary data. Across the 22 utilities I identified there is significant variation. The customer charges of those utilities range from $5.17/month to $46.02/month. This variation can be explained by a number of factors, such as the density of the utility service territory, the age of its infrastructure, the size of its customer base, and the structure of the utility (investor-owned, electric cooperative, etc.).
NorthWestern’s proposed basic service fee falls within the range of charges offered by the other Montana utilities. Figure 4 provides a summary of my survey. Further detail is provided in Appendix B.

**Figure 4: Survey of Residential Fixed Charges Offered in Montana**

Q. **HAVE YOU COMPARED NORTHWESTERN'S PROPOSED BASIC SERVICE FEES TO THOSE OF UTILITIES OUTSIDE OF MONTANA?**

A. Yes. To create an additional relevant comparison group, I also surveyed residential fixed charges offered by 16 similarly-sized investor-owned utilities in the Northwest U.S.⁴⁰ NorthWestern currently offers the lowest fixed charge.

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⁴⁰ I identified the sample of comparable IOUs using EIA Form 861 data. First, I selected nine states surrounding Montana: Colorado, Idaho, North Dakota, Nebraska, Oregon, South Dakota, Utah,
across all these utilities. NorthWestern’s proposed fixed charge of $5.60/month would still be lower than the fixed charge of 13 of the 16 utilities surveyed. Additional detail behind my survey of basic service fees, including other benchmarking comparisons, is provided in Appendix B.

VI. CONCLUSION

Q. WHAT DO YOU CONCLUDE ABOUT THE RESIDENTIAL NEM RATE PROPOSAL?

A. On behalf of NorthWestern, I have proposed the creation of a separate rate class for future residential NEM customers, and a cost-based three-part rate for these customers that is consistent with the widely-accepted principles of rate design. I support NorthWestern’s plan to make this the standard rate for all its future residential NEM customers. Moving to three-part rates provides proper price signals to customers by promoting economic efficiency and equity, facilitating the integration of distributed energy resources with the grid, and stimulating the cost-effective deployment of other innovative technologies such as customer-situated battery storage.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

Washington, and Wyoming. Then, I selected the 2 largest IOUs in each of these states. Lastly, I collected fixed charges for each utility’s standard residential rate from its tariff sheet (found on the utilities’ respective online websites).
## APPENDIX A: GLOSSARY OF ACRONYMS

### Table 6: Glossary of Acronyms in Testimony

<table>
<thead>
<tr>
<th>Acronym</th>
<th>Description</th>
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<tbody>
<tr>
<td>AMI</td>
<td>Advanced Metering Infrastructure</td>
</tr>
<tr>
<td>APS</td>
<td>Arizona Public Service</td>
</tr>
<tr>
<td>C&amp;I</td>
<td>Commercial and Industrial</td>
</tr>
<tr>
<td>ECOS</td>
<td>Embedded Cost of Service</td>
</tr>
<tr>
<td>ESS-1</td>
<td>Electric Supply Service</td>
</tr>
<tr>
<td>IOU</td>
<td>Investor-Owned Utility</td>
</tr>
<tr>
<td>IPC</td>
<td>Idaho Power Company</td>
</tr>
<tr>
<td>IPUC</td>
<td>Idaho Public Utilities Commission</td>
</tr>
<tr>
<td>KCC</td>
<td>Kansas Corporation Commission</td>
</tr>
<tr>
<td>kW</td>
<td>Kilowatt</td>
</tr>
<tr>
<td>kWh</td>
<td>Kilowatt Hour</td>
</tr>
<tr>
<td>NEM</td>
<td>Net Energy Metering</td>
</tr>
<tr>
<td>PV</td>
<td>Photovoltaic</td>
</tr>
<tr>
<td>REDS-1</td>
<td>Residential Electric Delivery Service</td>
</tr>
<tr>
<td>SRP</td>
<td>Salt River Project</td>
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</table>
This appendix provides a survey of residential fixed charges. Figure 5 presents residential fixed charges for all Montana utilities. Figure 6 also shows residential fixed charges but only for Montana utilities with 10,000 customers or more. Figure 7 presents residential fixed charges for large IOUs in nearby states. NorthWestern’s current basic service fee and the basic service fee proposed in this proceeding are highlighted in the figures.
Figure 5: Residential Fixed Charge Survey: All Montana Utilities

The sample analyzed in Figure 5 includes all Montana utilities (as per EIA Form 861). I collected fixed charges for each utility from its tariff sheet (found on the utilities’ respective online websites). Utility tariffs are as of September 2018. Some utilities were excluded because tariffs were unavailable online. For relevance, I excluded small utilities serving less than 150 customers. I also eliminated any utilities which had a fixed charge that applied to both residential and non-residential customers, as is the case for some cooperatives. In the figure, “NorthWestern Allocated Cost” represents the allocated cost in the ECOS for the residential class of $10.08; the allocated cost for NEM customers of $10.30 is not shown.
Figure 6: Residential Fixed Charge Survey: Montana Utilities with at least 10,000 Customers

Similar to Figure 5, Figure 6 presents residential fixed charges for Montana utilities, limiting the sample of utilities analyzed to the ones with 10,000 customers or more.
I identified the sample of comparable IOUs analyzed in Figure 7 using EIA Form 861 data. First, I selected nine states surrounding Montana: Colorado, Idaho, North Dakota, Nebraska, Oregon, South Dakota, Utah, Washington, and Wyoming. Then, I selected the 2 largest IOUs in each of these states. Lastly, I collected fixed charges for each utility’s standard residential rate from its tariff sheet (found on the utilities’ respective online websites). Utility tariffs are as of September 2018.
There are at least 50 utilities in 24 states that offer 60 three-part rates to residential customers. These rates are listed in Table 7. The structure of three-part rates offered by utilities across the U.S. varies significantly across multiple dimensions, as shown in Figure 8. The proposed rate is generally aligned with characteristics often observed in other jurisdictions. Additionally, the level of the proposed demand charge is broadly similar to that of residential demand charges offered by other utilities, as shown in Figure 9.
Table 7: List of U.S. Utilities Offering a Demand Charge to Residential Customers

<table>
<thead>
<tr>
<th></th>
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<tr>
<td>[1]</td>
<td>Alabama Power</td>
<td>Investor Owned</td>
<td>AL</td>
<td>1,262,752</td>
<td>14.50</td>
<td>1.50</td>
<td>Any time</td>
<td>15 min</td>
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<td>Voluntary</td>
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<td>[3]</td>
<td>Albemarle Electric Membership Corp</td>
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<td>NC</td>
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<td>13.50</td>
<td>Peak Coincident</td>
<td>15 min</td>
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<td>Voluntary</td>
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<td>[4]</td>
<td>Alliant Energy (IPL)</td>
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<td>IA</td>
<td>402,199</td>
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<td>Voluntary</td>
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<td>3.00</td>
<td>Peak Coincident</td>
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<td>Yes</td>
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<td>Voluntary</td>
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<td>Arizona Public Service</td>
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<td>1,061,814</td>
<td>18.02</td>
<td>8.40</td>
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<td>60 min</td>
<td>Yes</td>
<td>All</td>
<td>Voluntary</td>
</tr>
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<td>[7]</td>
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<td>18.02</td>
<td>17.44</td>
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<td>60 min</td>
<td>Yes</td>
<td>All</td>
<td>Voluntary</td>
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<td>Black Hills Power</td>
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<td>8.10</td>
<td>Any time</td>
<td>15 min</td>
<td>No</td>
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<td>Any time</td>
<td>15 min</td>
<td>No</td>
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<td>5.75</td>
<td>Any time</td>
<td>15 min</td>
<td>No</td>
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<td>Voluntary</td>
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<td>15 min</td>
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<td>30 min</td>
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<td>5.60</td>
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<td>Voluntary</td>
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<td>0.75</td>
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<td>15 min</td>
<td>No</td>
<td>All</td>
<td>Voluntary</td>
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<td>#</td>
<td>Utility</td>
<td>Ownership</td>
<td>State</td>
<td>Residential Customers Served</td>
<td>Fixed charge ($/month)</td>
<td>Demand Charge ($/kW-month)</td>
<td>Timing of demand measurement</td>
<td>Demand Interval</td>
<td>Combined with Energy TOU?</td>
<td>Applicable Residential or Voluntary</td>
<td></td>
</tr>
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<td>Louisville Gas and Electric</td>
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<td>KY</td>
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<td>7.68</td>
<td>7.68</td>
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<td>No</td>
<td>All Voluntary</td>
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<td>CO</td>
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<td>23.50</td>
<td>9.80</td>
<td>7.55</td>
<td>Any time</td>
<td>15 min</td>
<td>No</td>
<td>All Voluntary</td>
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<td>SC</td>
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<td>12.00</td>
<td>12.00</td>
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<td>No</td>
<td>All Voluntary</td>
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<td>KS</td>
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<td>6.40</td>
<td>6.40</td>
<td>Any time</td>
<td>15 min</td>
<td>No</td>
<td>All Voluntary</td>
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<td>Investor Owned</td>
<td>NV</td>
<td>291,401</td>
<td>10.25</td>
<td>0.35(daily)</td>
<td>0.55(daily)</td>
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<td>No</td>
<td>All Voluntary</td>
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<td>NV Energy (SPP)</td>
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<td>NV</td>
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<td>0.26(daily)</td>
<td>0.93(daily)</td>
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<td>Any time</td>
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<td>[38]</td>
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<td>8.00</td>
<td>Any time</td>
<td>60 min</td>
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<td>60 min</td>
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<td>7.95</td>
<td>5.53</td>
<td>Any time</td>
<td>60 min</td>
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<td>All Voluntary</td>
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<td>Political Subdivision</td>
<td>AZ</td>
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<td>NEM Only</td>
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<td>5,236</td>
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<td>18,540</td>
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<td>All Voluntary</td>
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<td>Any time</td>
<td>15 min</td>
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<td>Tuscan Electrical Power</td>
<td>Investor Owned</td>
<td>AZ</td>
<td>378,592</td>
<td>10.00</td>
<td>8.85</td>
<td>8.85</td>
<td>Peak Coincident</td>
<td>60 min</td>
<td>No</td>
<td>All Voluntary</td>
</tr>
<tr>
<td>[57]</td>
<td>Vigilante Electric Cooperative</td>
<td>Cooperative</td>
<td>MT</td>
<td>8,273</td>
<td>26.00</td>
<td>0.50 per KVA</td>
<td>0.50 per KVA</td>
<td>Any time</td>
<td>Unknown</td>
<td>No</td>
<td>All Mandatory</td>
</tr>
<tr>
<td>[58]</td>
<td>Westar Energy</td>
<td>Investor Owned</td>
<td>KS</td>
<td>537,214</td>
<td>18.50</td>
<td>6.91</td>
<td>2.13</td>
<td>Any time</td>
<td>30 min</td>
<td>No</td>
<td>All Voluntary</td>
</tr>
<tr>
<td>[59]</td>
<td>Xcel Energy (PSCo)</td>
<td>Investor Owned</td>
<td>CO</td>
<td>1,228,305</td>
<td>19.31</td>
<td>10.08</td>
<td>7.76</td>
<td>Any time</td>
<td>15 min</td>
<td>No</td>
<td>All Voluntary</td>
</tr>
<tr>
<td>[60]</td>
<td>Xcel Energy (PSCo)</td>
<td>Investor Owned</td>
<td>CO</td>
<td>1,228,305</td>
<td>6.54</td>
<td>13.38</td>
<td>10.66</td>
<td>Peak Coincident</td>
<td>60 min</td>
<td>No</td>
<td>All Voluntary</td>
</tr>
</tbody>
</table>
Notes accompanying table of U.S. residential demand charge offerings

Sources: Utility tariffs as of September 2018, and EIA Form 861 from 2016 (for Utility ownership and Residential Customers Served columns).

Notes: For some utilities, the monthly fixed charge has been calculated by multiplying a daily charge by 30.5. When the utility offered different basic service charges for single-phase and three-phase services, the single-phase service charge was selected.

[2]: Mandatory if customer consumes more than 5,000 kWh per month for three consecutive months or has a recorded peak demand of 20 KW for three consecutive months.
[4]: Only offered on a pilot basis. The billing demand is the sum of the highest hourly demand during on-peak hours of the current month plus 50% of the amount by which the highest hourly demand during the off-peak hours exceeds the highest on-peak demand.
[6]-[7]: The monthly fixed charge is a daily basic service charge multiplied by 30.5 days.
[8]-[9]: Black Hills also offers an optional time-of-use rate that includes both energy and demand charges for customers owning demand controllers.
[18]: The demand charge only applies to demand measured in excess of 10 kW.
[22]: Demand charge is the sum of the distribution demand charge and the generation demand charge. The distribution demand charge is $1.549/kW and the generation demand charge is $3.910/kW for the summer and $2.242/kW for the winter.
[32]: The demand rate is closed to new customers after December 31, 2014.
[34]: The demand charge is based on the greater of the highest average 15 minute kW demand measured during the period for which the bill is rendered, and 80% of the average 15 minute maximum demand for the last three summer months.
[35]-36: Rates will be in place starting October 1, 2018. The billing demand is calculated as the sum of the customer's daily 15-min maximum demand during the billing period.
[38]-40: Demand is measured as the maximum winter demand for the most recent 12 months. New customers have an assumed demand of 3 kW for their first year. Fixed charge for MN is customer charge per month plus facilities charge per month. Fixed charge for ND and SD is just customer charge per month.
[41]: The demand charge is only applicable to three-phase customers.
[43]: Billing demand is the greater of the current month actual demand or 50% of peak demand established in the preceding eleven months.
[46]: Customers below 200 amps pay a fixed charge of $32.44 per month and customers above 200 amps pay $45.44 per month. Demand charges vary across three seasons: Winter, Summer (May, June, September, and October), and On-Peak Summer (July and August). The summer demand charges shown here apply for the On-Peak Summer period. The (on-peak) summer demand charge is $9.59 for up to 3kW of demand, 17.82 for the next 7kW, and 34.19 for over 10kW. The winter demand charge is $3.55 for up to 3kW, 5.68 for the next 7kW, and $9.74 over 10kW. The utility is experimentally offering the rate plan to a limited number of non-NEM customers.
[51]: The demand charge is based on the greater of the measured demand for the current month and 85% of the highest recorded demand established during the preceding eleven months. The rate is mandatory for all residential customers with monthly consumption equal to or greater than 1,800 kWh, measured on a rolling 12 month average basis.
[52]: The basic service charge is calculated as the average of the overhead service charge ($30/month) and the underground service charge ($32/month).
[55]-56: The demand charge is $8.85/kW for the first 7kW and $12.85/kW for any additional kWs.
[57]: The demand charge applies only to kVA greater than 15 kVA.
[58]: Not available to new customers since 2006.
[59]: Xcel Energy Residential Demand Service (Schedule RD).
[60]: Xcel Energy Residential Demand-Time Differentiated Rates Service (Schedule RD-TDR).
Figure 8: Characteristics of 60 Three-Part Residential Rate Offerings

- Seasonal differentiation?
  - Yes
  - No

- Peak-constrained?
  - Yes
  - No

- Combined with TOU?
  - Yes
  - No

- Mandatory?
  - Yes
  - No

- Interval of demand measurement
  - 15-min
  - 30-min
  - 60-min
  - Unknown
Utility tariffs are as of September 2018. Each bar represents the level of the demand charge in one rate offering. When the demand charge levels are different in summer and winter, the winter charge is represented by a light gray bar and the summer charge is the sum of the light gray and dark gray bars. Demand charges that do not vary by season are represented with light gray bars. The proposed demand charge for Northwestern is shown in teal. Alaska Electric Light and Power has a winter demand charge of $10.76/kW (shown in figure) and a summer demand charge of $6.51/kW.
### APPENDIX D: MONTANA UTILITIES OFFERING A DEMAND CHARGE TO C&I CUSTOMERS

Table 8: Montana Utilities Offering a Demand Charge to C&I Customers\(^{45}\)

<table>
<thead>
<tr>
<th>Utility</th>
<th>Utility Ownership</th>
<th>Customers Served</th>
<th>Mandatory for Some C&amp;I Customers?</th>
<th>Mandatory for All C&amp;I Customers?</th>
</tr>
</thead>
<tbody>
<tr>
<td>Beartooth Electric Coop</td>
<td>Cooperative</td>
<td>5,596</td>
<td>✓</td>
<td></td>
</tr>
<tr>
<td>Big Horn County Elec Coop</td>
<td>Cooperative</td>
<td>3,696</td>
<td>✓</td>
<td></td>
</tr>
<tr>
<td>Fall River Rural Elec Coop</td>
<td>Cooperative</td>
<td>1,944</td>
<td></td>
<td>✓</td>
</tr>
<tr>
<td>Fergus Electric Coop</td>
<td>Cooperative</td>
<td>6,383</td>
<td>✓</td>
<td></td>
</tr>
<tr>
<td>Flathead Electric Coop</td>
<td>Cooperative</td>
<td>64,730</td>
<td>✓</td>
<td></td>
</tr>
<tr>
<td>Glacier Electric Coop</td>
<td>Cooperative</td>
<td>7,680</td>
<td></td>
<td>✓</td>
</tr>
<tr>
<td>Hill County Electric Coop</td>
<td>Cooperative</td>
<td>3,822</td>
<td>✓</td>
<td></td>
</tr>
<tr>
<td>Lincoln Electric Coop</td>
<td>Cooperative</td>
<td>5,763</td>
<td></td>
<td>✓</td>
</tr>
<tr>
<td>Lower Yellowstone</td>
<td>Cooperative</td>
<td>5,043</td>
<td>✓</td>
<td></td>
</tr>
<tr>
<td>Marias River Electric Coop</td>
<td>Cooperative</td>
<td>3,856</td>
<td></td>
<td>✓</td>
</tr>
<tr>
<td>McCon Electric Coop</td>
<td>Cooperative</td>
<td>5,264</td>
<td>✓</td>
<td></td>
</tr>
<tr>
<td>Mission Valley Power</td>
<td>Federal</td>
<td>21,233</td>
<td>✓</td>
<td></td>
</tr>
<tr>
<td>Missoula Electric Coop</td>
<td>Cooperative</td>
<td>14,505</td>
<td>✓</td>
<td></td>
</tr>
<tr>
<td>Montana-Dakota Utilities Co</td>
<td>Investor Owned</td>
<td>25,791</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Northern Lights</td>
<td>Cooperative</td>
<td>4,256</td>
<td>✓</td>
<td></td>
</tr>
<tr>
<td>NorthWestern Energy (MT)</td>
<td>Investor Owned</td>
<td>362,291</td>
<td>✓</td>
<td></td>
</tr>
<tr>
<td>Park Electric Coop</td>
<td>Cooperative</td>
<td>5,829</td>
<td>✓</td>
<td></td>
</tr>
<tr>
<td>Powder River Energy MT</td>
<td>Cooperative</td>
<td>181</td>
<td>✓</td>
<td></td>
</tr>
<tr>
<td>Ravalli County Elec Coop</td>
<td>Cooperative</td>
<td>10,219</td>
<td>✓</td>
<td></td>
</tr>
<tr>
<td>Sun River Electric Coop</td>
<td>Cooperative</td>
<td>5,783</td>
<td></td>
<td>✓</td>
</tr>
<tr>
<td>Tongue River Electric Coop</td>
<td>Cooperative</td>
<td>4,987</td>
<td>✓</td>
<td></td>
</tr>
<tr>
<td>Vigilante Electric Coop</td>
<td>Cooperative</td>
<td>9,704</td>
<td>✓</td>
<td></td>
</tr>
<tr>
<td>Yellowstone Valley Elec Coop</td>
<td>Cooperative</td>
<td>19,321</td>
<td>✓</td>
<td></td>
</tr>
</tbody>
</table>

\(^{45}\) Columns [1] and [2] from EIA Form 861 (2016). Columns [3] and [4] from utility tariffs as of September 2018. Some utilities were excluded as tariffs were unavailable online.
APPENDIX E: DESIGN OF AN ALTERNATIVE
TWO-PART RATE FOR NEM CUSTOMERS

An alternative to a three-part rate is maintaining a two-part rate and collecting a higher portion of revenues through the basic service charge. In this scenario, the energy charge would equal that of the three-part rate at $0.065698/kWh, a demand charge would not be added, and the basic service charge would increase to $55.80/month, as shown in Table 9.

Table 9: Alternative Two-Part Rate Design for NEM Customers

<table>
<thead>
<tr>
<th>Charge</th>
<th>Units</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Basic Service Charge</td>
<td>$/month</td>
<td>55.80</td>
</tr>
<tr>
<td>Energy Charge</td>
<td>$/kWh</td>
<td>0.065698</td>
</tr>
<tr>
<td>Supply</td>
<td>$/kWh</td>
<td>0.065698</td>
</tr>
<tr>
<td>Transmission</td>
<td>$/kWh</td>
<td>0.000000</td>
</tr>
<tr>
<td>Distribution</td>
<td>$/kWh</td>
<td>0.000000</td>
</tr>
<tr>
<td>Other Applicable Charges</td>
<td>$/kWh</td>
<td>0.002271</td>
</tr>
</tbody>
</table>
This section describes the characteristics of residential NEM customers as well as the NEM and non-NEM residential data used in my analysis. NorthWestern currently has 1,823 residential NEM customers. Both the number of NEM installations and the average installed capacity per customer are growing over time, as shown in Figure 10 and Figure 11.

**Figure 10: Number of Distributed Generation Installations over Time**
The load interval data is available for 49 of those NEM customers. The section below describes the NEM and non-NEM residential data used in my analysis and summarizes the adjustments I made to the data for the purpose of my analysis.

### NEM Residential Load Data

NorthWestern provided 15-min interval load data for 49 residential customers that installed distributed energy resources and became NEM customers before 2016. The dataset spans the period from January 2016 to June 2018. All customers had a full year of load data. All results in the testimony using NEM residential load data are weighted by stratum to make them representative of the NEM residential class. Strata for the NEM residential class are defined by installed capacity. NorthWestern provided a file with the installation data and capacity for all NEM customers. To calculate each customer’s relative weight, first I calculated the NEM residential class stratum weights by counting the total number of customers in the NEM residential class in each stratum based on their
respective installed capacity. For each month of interval load data, I counted the number of customers in each stratum with data available. Then, I divided the weight of each stratum by the number of customers in each stratum.

**Non-NEM Residential Load Data**

NorthWestern provided 15-min interval load data for 180 customers. The dataset spans the period from July 2017 to June 2018. All customers had a full year of load data. The results in the testimony using NEM residential load data are weighted by stratum to make them representative of the NEM residential class. NorthWestern provided the weights of each of the strata in the NEM residential class obtained from a study carried out in 2010. To calculate each customer’s relative weight, each month I counted the number of customers in each stratum with data available. Then, I divided the weight of each stratum by the number of customers in each stratum.
This section describes the steps I used to calculate the proposed three-part rate. NorthWestern is proposing to recover 96 percent of costs allocated to the residential customer class, as per the ECOS study from Normand Direct Testimony. Under the proposed three-part rate, revenues recovered from future NEM customers would also be 96 percent of allocated costs to match the percentage of revenue recovery from residential non-NEM customers. An underlying assumption of this analysis is that future residential NEM customers will have characteristics similar to those of current residential NEM customers.

The customer charge is set at $5.60 per customer per month to reflect the charge proposed for residential non-NEM customers. The volumetric energy charge is set at $0.065698/kWh to equal the residential supply rate. This charge comprises of the sum of the residential Generation Rate, residential Two Dot Rate, and the residential base rate for the Power Cost and Credits Adjustment Mechanism (PCCAM).

The demand charge is set to recover the remainder of the target revenues, which primarily includes transmission and distribution costs, as well as a small portion of customer costs. To obtain the level of the demand charge, I first determine the portion of the target revenues that would not be covered by the fixed charge and volumetric energy charge (assuming an average monthly net energy consumption per customer of 567 kWh, per Normand Direct Testimony). Next, I calculated the level of the demand charge that would be necessary to recover the remaining target revenue (assuming an average
monthly peak demand per customer of 5.8 kW, per my analysis of the NEM interval data).

Finally, I determined the share of the demand charge allocated to transmission and distribution (16 percent for transmission and 84 percent for distribution) based on a proportional allocation of total allocated residential NEM transmission and distribution costs in the ECOS in Normand Direct Testimony.
Dr. Ahmad Faruqui is an energy economist whose work is focused on the efficient use of energy. His areas of expertise include rate design, demand response, energy efficiency, distributed energy resources, advanced metering infrastructure, plug-in electric vehicles, energy storage, inter-fuel substitution, combined heat and power, microgrids, and demand forecasting. He has worked for nearly 150 clients on 5 continents. These include electric and gas utilities, state and federal commissions, independent system operators, government agencies, trade associations, research institutes, and manufacturing companies. Ahmad has testified or appeared before commissions in Alberta (Canada), Arizona, Arkansas, California, Colorado, Connecticut, Delaware, the District of Columbia, FERC, Illinois, Indiana, Kansas, Maryland, Minnesota, Nevada, Ohio, Oklahoma, Ontario (Canada), Pennsylvania, ECRA (Saudi Arabia), and Texas. He has presented to governments in Australia, Egypt, Ireland, the Philippines, Thailand and the United Kingdom and given seminars on all 6 continents. His research has been cited in Business Week, The Economist, Forbes, National Geographic, The New York Times, San Francisco Chronicle, San Jose Mercury News, Wall Street Journal and USA Today. He has appeared on Fox Business News, National Public Radio and Voice of America. He is the author, co-author or editor of 4 books and more than 150 articles, papers and reports on energy matters. He has published in peer-reviewed journals such as Energy Economics, Energy Journal, Energy Efficiency, Energy Policy, Journal of Regulatory Economics and Utilities Policy and trade journals such as The Electricity Journal and the Public Utilities Fortnightly. He holds B.A. and M.A. degrees from the University of Karachi, where he was awarded the Gold Medal in Economics, 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 the recipient of a dissertation grant from the Kellogg Foundation.

AREAS OF EXPERTISE

- **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.
Ahmad Faruqui

- **Innovative pricing.** He has identified, designed and analyzed the efficiency and equity benefits of introducing innovative pricing designs such as three-part rates, including fixed monthly charges, demand charges and time-varying energy charges; dynamic pricing rates, including critical peak pricing, variable peak pricing and real-time pricing; time-of-use pricing; and inclining block rates.

- **Regulatory strategy.** He has helped design forward-looking programs and services that exploit recent advances in rate design and digital technologies in order to lower customer bills and improve utility earnings while lowering the carbon footprint and preserving system reliability.

- **Cost-benefit analysis of advanced metering infrastructure.** He has assessed the feasibility of introducing smart meters and other devices, such as programmable communicating thermostats that promote demand response, into the energy marketplace, in addition to new appliances, buildings, and industrial processes that improve energy efficiency.

- **Demand forecasting and weather normalization.** He has pioneered the use of a wide variety of models for forecasting product demand in the near-, medium-, and long-term, using econometric, time series, and engineering methods. These models have been used to bid into energy procurement auctions, plan capacity additions, design customer-side programs, and weather normalize sales.

- **Customer choice.** He has developed methods for surveying customers in order to elicit their preferences for alternative energy products and alternative energy suppliers. These methods have been used to predict the market size of these products and to estimate the market share of specific suppliers.

- **Hedging, risk management, and market design.** He has helped design a wide range of financial products that help customers and utilities cope with the unique opportunities and challenges posed by a competitive market for electricity. He conducted a widely-cited market simulation to show that real-time pricing of electricity could have saved Californians millions of dollars during the Energy Crisis by lowering peak demands and prices in the wholesale market.

- **Competitive strategy.** He has helped clients develop and implement competitive marketing strategies by drawing on his knowledge of the energy needs of end-use customers, their values and decision-making practices, and their competitive options. He has helped companies reshape and transform their marketing organization and reposition...
Ahmad Faruqui

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.

- **Academic experience.** He has given lectures at the University of California, Berkeley, University of California, Davis, Harvard University, University of Idaho, University of Karachi, Massachusetts Institute of Technology, Michigan State University, Northwestern University, University of San Francisco, San Jose State University, Stanford University, University of Virginia, and University of Wisconsin-Madison. Additionally, he has led a variety of professional seminars and workshops on public utility economics around the world. Finally, he has taught economics at the university level at San Jose State University, University of California, Davis, and the University of Karachi.

**EXPERIENCE**

**Innovative Pricing**

- **Cost of Service and Tariff Design Study:** for a large electric utility in South-East Asia, Brattle provided consulting services for their cost of service and tariff design studies for incentive based regulation, covering regulatory period 2 (2018-2020). Our work focused on understanding the cost drivers, reviewing the extent to which the current tariffs reflect the cost drivers, and developing new tariffs that better align with current and projected costs.

- **Impact Analysis for TOU Rates in Ontario.** Measured the impacts of a system-wide Time of Use (TOU) deployment in the province of Ontario, Canada, on behalf of the Ontario Power Authority. To account for the lack of a designated control group, Brattle created a quasi-experimental design that took advantage of differences in the timing of the TOU rollout.
Ahmad Faruqui

• **Measurement and evaluation for in-home displays, home energy controllers, smart appliances, and alternative rates for Florida Power & Light (FPL).** Carried out a 2-year impact evaluation of a dynamic and enabling technology pilot program. Used econometric methods to estimate the changes in load shapes, changes in peak demand, and changes in energy consumption for three different treatments. The results of this study were shared with Department of Energy as to fulfill the data reporting requirements of FPL’s Smart Grid Investment Grant.

• **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.

- **Analyzed the Economics of Self-Generation of Steam.** 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 the probability of self-generation 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.
Ahmad Faruqui

- **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**

- **Combined Heat and Power Generation Study.** Investigated the economic potential for combined heat and power and regulatory policies to unlock that potential in a Middle Eastern country.

- **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.
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• **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.

• **Demand response program review for Integrated Resource Plan development.** In response to legislation requiring the Connecticut utilities to jointly prepare a 10-year integrated resource plan, we conducted the analysis and helped prepare the plan. In coordination with the two leading utilities in the state, we conducted a detailed analysis of alternative resource solutions (both supply- and demand-side), drafted the report, and presented it to the Connecticut Energy Advisory Board. The analysis involved a detailed review and critique of the companies’ proposed DR programs.

• **Integration of DR into wholesale energy markets.** Developed a whitepaper, “Fostering Economic Demand Response in the Midwest ISO,” evaluating alternative approaches to efficiently integrating DR into its energy markets while encouraging increased participation. This work involved interviewing market participants and analyzing several approaches to economic DR regarding economic efficiency, participation rates, operational fit with other ISO rules, and susceptibility to state-level and ISO-level implementation barriers. This work also involved an extensive survey of DR programs (qualification criteria, bidding rules, incorporation into market clearing software, measurement and verification, and settlement) in ISO/Regional Transmission Organization (RTO) markets around the country. The project also required a detailed review of existing DR program tariffs for utilities in the RTO’s service territory and development of a matrix for summarizing the various characteristics of these programs.

• **Integration of DR into resource adequacy constructs.** For the Midwest ISO, assisted in developing qualification criteria for DR as a capacity resource (we also developed estimates of likely future contributions of DR to resource adequacy, for use by their transmission planning group). For PJM, as part of our review of its capacity market, we developed recommendations on how to treat DR comparably to generation resources while accounting for the special attributes of DR. Our recommendations addressed product definition, auction rules, and penalty
provisions. For the Connecticut utilities in their integrated resource planning, we evaluated future resource needs given various levels of demand response programs.

- **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

- **Electricity Sales and Peak Demand Forecasting Study:** for a large electric utility in South-East Asia, Brattle provided consulting services that involved assessing the performance of their load forecasting methodology and developing new models that provided more accurate forecasts.

- **Electricity Consumption and Maximum Demand Forecasting:** for a medium-sized utility in Asia-Pacific, Brattle provided consulting services on forecasting electricity
consumption and maximum demand. Our work focused on analyzing drivers of growth in electricity sales, reviewed model performance, identified best practices and provided recommended approaches for analyzing trends in electricity sales and load forecasting.

- **Forecasting Review.** Evaluated and critiqued the process conducted by an Australian utility company’s electricity market forecasting, including the forecasting of electricity demand, supply, and price.

- **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-
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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**

**Arizona**

Direct Testimony before the Arizona Corporation Commission on behalf of Arizona Public Service Company, in the matter of the Application of Arizona Public Service Company for a Hearing to Determine the Fair Value of the Utility Property of the Company for Ratemaking Purposes, to Fix a Just and Reasonable Rate of Return Thereon, to Approve Rate Schedules Designed To Develop Such Return, Docket No. E-01345A-16-0036, June 1, 2016.


**Arkansas**

Direct Testimony before the Arkansas Public Service Commission on behalf of Entergy Arkansas, Inc., in the matter of Entergy Arkansas, Inc.’s Application for an Order Finding the Deployment of Advanced Metering Infrastructure to be in the Public Interest and Exemption from Certain Applicable Rules, Docket No. 16-060-U, September 19, 2016.

**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.

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Colorado


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.

Idaho


Illinois


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

Rebuttal Testimony before the Illinois Commerce Commission on behalf of Commonwealth Edison Company in the matter of the Petition to Approve an Advanced Metering Infrastructure Pilot Program and Associated Tariffs, No. 09-0263, August 14, 2009.

**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**


**Louisiana**


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

Maryland

Direct Testimony before the Maryland Public Service Commission, on behalf of Potomac Electric Power Company in the matter of the Application of Potomac Electric Power Company for Adjustments to its Retail Rates for the Distribution of Electric Energy, April 19, 2016.

Rebuttal Testimony before the Maryland Public Service Commission on behalf of Baltimore Gas and Electric Company in the matter of the Application of Baltimore Gas and Electric Company for Adjustments to its Electric and Gas Base Rates, Case No. 9406, March 4, 2016.

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


Mississippi

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

Nevada

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

**New Mexico**

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

**Oklahoma**


Direct Testimony before the Corporation Commission of Oklahoma on behalf of Oklahoma Gas and Electric Company in the matter of the Oklahoma Gas and Electric Company for an Order of the Commission Authorizing Applicant to modify its Rates, Charges and Tariffs for Retail Electric Service in Oklahoma, Cause No. PUD 201500273, December 18, 2015.


**Pennsylvania**


**Washington**

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


Chapters in Books


Technical Reports


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


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


Articles and Papers


http://www.energyregulationquarterly.ca/articles/moving-forward-with-tariff-reform#sthash.ZADdmZ2h.D2l1yz9z.dpbs

http://mydigimag.rrd.com/publication/?i=4353434"issue_id":435343,"page":42]


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https://www.fortnightly.com/fortnightly/2017/07/rethinking-customer-research

http://www.energyregulationquarterly.ca/articles/do-manufacturing-firms-relocate-in-response-to-rising-electric-rates#sthash.uLnrPMwh.dpbs

https://www.fortnightly.com/fortnightly/2017/05/dynamic-pricing-works-hot-humid-climate


“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](http://www.fortnightly.com/fortnightly/2014/08/smart-default?page=0%2C0&authkey=e5b59c3e26805e2c6b9e469cb9c1855a9b0f18c67bbe7d8d4ca08a8abd39c54d)


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


http://www.fortnightly.com/fortnightly/2013/07/benchmarking-your-rate-case

“Surviving Sub-One-Percent Growth,” Electricity Policy, June 2013.
http://www.electricitypolicy.com/articles/5677-surviving-sub-one-percent-growth

http://www.fortnightly.com/fortnightly/2012/12/demand-growth-and-new-normal?page=0%2C1&authkey=4a6cf0a67411ee5e7c2aee5da4616b72fde10e3fbe215164cd4e5dbd8e9d0c98

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http://www.drgscoalition.org/resources/other/Pricing_Programs_TOU_and_RTP.pdf


http://www.crai.com/uploadedFiles/RELATING_MATERIALS/Publications/files/Controlling%20the%20Thirst%20for%20Demand.pdf


“Bundling Value-Added and Commodity Services in Retail Electricity Markets,” with Kelly Eakin, 


“Mitigating Price Volatility by Connecting Retail and Wholesale Markets,” with Doug Caves and Kelly 

“The Brave New World of Customer Choice,” with J. Robert Malko, appears in *Customer Choice: 

“What’s in Our Future?” with J. Robert Malko, appears in *Customer Choice: Finding Value in Retail 


“Forecasting in a Competitive Environment: The Need for a New Paradigm,” *Demand Forecasting for 

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


“Promotion of Energy Efficiency through Environmental Compliance: Lessons Learned from a Southern 
California Case Study,” with Peter F. Kyricopoulos and Ishtiaq Chisti. *ACEEE 1995 Summer Study on 


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