Rocky Mountain Power
Docket No. 16-035-____
Witness: Joelle R. Steward

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

Direct Testimony of Joelle R. Steward

November 2016

Q. Please state your name, business address and present position with PacifiCorp, dba Rocky Mountain Power ("the Company").

A. My name is Joelle R. Steward. My business address is 1407 West North Temple, Salt Lake City, Utah 84116. My present position is Director, Rates & Regulatory Affairs for the Company.

Qualifications

Q. Briefly describe your education and professional background.

A. I have a B.A. degree in Political Science from the University of Oregon and an M.A. in Public Affairs from the Hubert Humphrey Institute of Public Policy at the University of Minnesota. Between 1999 and March 2007, I was employed as a Regulatory Analyst with the Washington Utilities and Transportation Commission. I joined the Company in March 2007 as a Regulatory Manager, responsible for all regulatory filings and proceedings in Oregon. In February 2012, I assumed responsibilities overseeing cost of service and pricing for PacifiCorp. In May 2015, I assumed my current position, with broader oversight over Rocky Mountain Power's regulatory affairs in addition to the cost of service and pricing responsibilities.

Q. Have you appeared as a witness in previous regulatory proceedings?

A. Yes. I have testified in regulatory proceedings in Idaho, Oregon, Utah, Washington and Wyoming.

Purpose and Summary of Testimony

Q. What is the purpose of your testimony?

A. My testimony explains and supports the Company's filing and the proposed new tariffs – Schedule 136, Net Metering Program, and Schedule 5, Residential Service for Customer Generators. I also (i) explain the Company's proposal for new or updated application fees for interconnection requests based on a more current assessment of the administrative costs and (ii) sponsor the conforming changes in the interconnection agreements.

Q. Please summarize your testimony.

A. The Company has experienced extensive growth in net metering since the Commission initiated this proceeding following the Company's 2014 general rate case. In light of that growth, the Company implemented the framework established by the Commission in the first phase of this proceeding to evaluate whether the costs of the net metering program exceed the benefits, as required by Utah Code § 54-15-105.1(1). The framework analysis is based on calendar year 2015 results, which coincides with the availability of data from the Company's load research study for residential net metering. The results of this analysis show that, under the current rate structure, the costs of net metering exceeded the benefits by $2.0 million in 2015, of which $1.7 million is related to residential net metering customers. This cost impact has already increased to at least $6.5 million per year due to the growth in net metering in 2016. The Company estimates that, by 2020, the cost shift would be $27 million per year based on current growth projections. As a result, other customers will see higher rates in the future in order to pay for these costs. The analysis shows that residential net metering customers pay only about 60 percent of the cost to serve them, whereas other residential customers pay on average 96 percent of their costs.

This result is largely attributed to the current rate structure for residential net metering customers. The current residential rate structure was designed to recover most costs through volumetric energy rates. Net metering customers currently receive compensation for their excess generation at the retail energy rate. Since this retail energy rate recovers most of the fixed costs necessary to serve customers, net metering customers are being compensated as much as 14.5 cents/kilowatt-hour ("kWh"), far in excess of the value of their energy to the system. In comparison, the Company pays small power producers less than 4 cents/kWh for their solar output through avoided cost prices.

Data from the load research study shows that the profile of residential net metering customers is distinctly different and, while those customers may take less energy (kWh) from the grid than before, their overall demand (kW) requirements are not reduced proportionally. Since most costs are driven by demand, the energy-based rate structure does not adequately cover costs to serve residential customer generators. The magnitude of the cost shift is not as significant for non-residential net metering customers because their rate structure already better captures differences in usage profiles among customers in the same class. To minimize the residential cost shift, the Company is proposing a new rate schedule and rate structure – Schedule 5, Residential Service for Customer Generators – for residential customers who apply to participate in net metering after the effective date of the proposed transitional net metering program tariff, Schedule 135A, which was filed concurrently with this compliance filing.

For Schedule 5, the Company is proposing a three-part rate structure, comprised of a monthly customer charge of $15.00; a demand charge for the peak periods of 3:00 p.m. to 8:00 p.m., Monday through Friday year round, with an additional peak period from 8:00 a.m. to 10:00 a.m., Monday through Friday in the winter months of October through April; and an energy charge. This rate structure will send a better price signal to individual customers because their rates will more closely align with the way costs are allocated in the cost of service study. Similar to non-residential rates, this rate structure rewards customers who use the grid more efficiently (i.e., higher load factor customers) with lower average rates. Residential customer generators would still receive compensation through the energy charge, which more closely approximates the cost to the Company to provide the equivalent energy. As such, a new residential net metering customer who uses about 1,000 kWh per month can still achieve bill savings between 11 percent and 60 percent, from their current bill, depending on how much their generation facility is able to offset their usage.

On Schedule 136, the Company is proposing to eliminate the option for new non-residential customers to receive compensation for their excess energy at the average retail rate, since this rate includes recovery of fixed costs. Non-residential customers may still choose between the two other compensation options, which are tied to avoided costs.

The Company is also proposing to increase the current net metering application fees. The increases are necessary to cover the administrative costs necessary to process applications. For Level 1 interconnections, the Company proposes to implement a one-time application fee of $60. For Level 2 and 3 interconnections, the Company proposes increasing the current fees to $75 plus $1.50 per kW, and $150 plus $3.00 per kW, respectively.

Lastly, to alleviate concerns the filing will result in increased revenues for the Company outside of a general rate case, the Company is willing to defer any difference in revenues between current rates and the new rates on Schedule 5. The Company would make a proposal for amortization of the deferral balance in its next general rate case.

Purpose of Filings

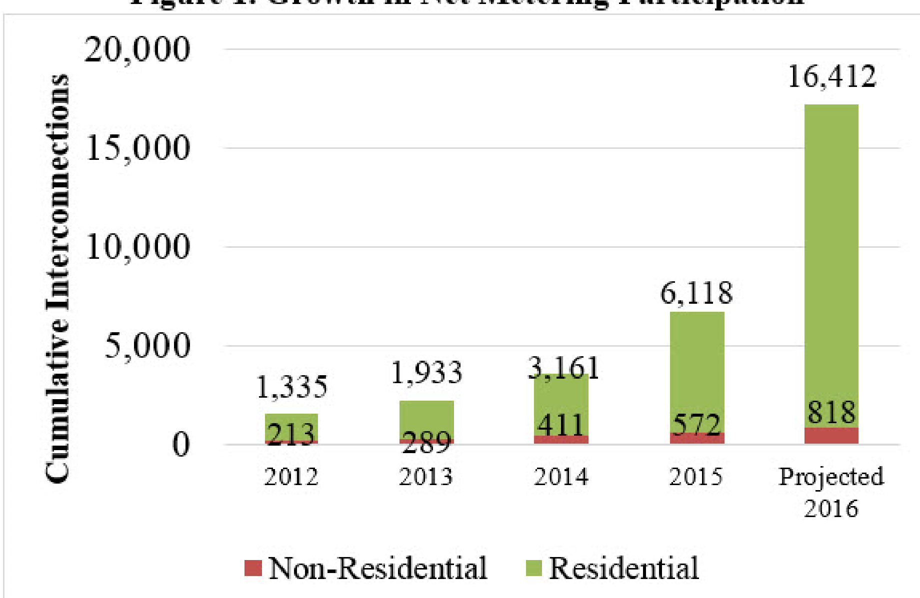
Q. Why is the Company making this filing?

A. In 2014, the Utah Legislature enacted Utah Code § 54-15-105.1 ("Net Metering Statute"), requiring the Commission to determine whether the costs of net metering exceed its benefits or vice versa and, if so, to determine an appropriate charge, credit, or rate structure based on that determination. The Commission initially considered this issue in the Company's 2014 general rate case, Docket No. 13-035-184 ("2014 GRC"), but opened Docket No. 14-035-114 to make the determinations mandated by the Net Metering Statute. The Company prepared the analyses set forth by the Commission's November 10, 2015 Order in Docket No. 14-035-114 (the “November 2015 Order”) to evaluate whether the costs of net metering program exceed the benefits or the benefits exceed the costs. The Company used a calendar year 2015 study period ("Study Period") for the analyses, which corresponds with the data collected from the Company's load research study for residential net metering customers. Over the Study Period, the Company had an average of about 5,000 net metering customers.

Q. Please summarize the current and forecast growth in net metering.

A. Since the Company initially raised concerns about cost shifting due to net metering in the 2014 GRC, there has been an increase of over 600 percent in the number of net metering participants. The Company is now seeing approximately 1000 new applications each month. The vast majority -- approximately 97 percent -- are from residential customers. With this growth rate, the Company projects that it will have over 16,000 residential net metering customers with nearly 100 MW of private customer generation in Utah by the end of 2016. Figure 1 below shows the growth in net metering by residential and non-residential.

Figure 1. Growth in Net Metering Participation



Growth in private generation is expected to continue into the future. For the 2017 Integrated Resource Plan, the Company commissioned an independent study to project the level of private generation growth over the next two decades based on updated information on technology costs, performance, incentives, and market conditions. This study projects an average of 40.5 MW per year of new private generation capacity in Utah over the next two decades in the base case.[1]

Q. Please summarize the analyses ordered by the Commission in the November 2015 Order.

A. In its November 2015 Order, the Commission established a framework that evaluates whether and how the net metering program impacts rates for other customers. The framework provides multiple views through two different analyses for perspective on how other customers' rates may be impacted by the net metering program.

The first analysis compares two cost of service studies over a test period; one that reflects the actual cost of service with net metering customers' participation (the "ACOS" study), and one under which the Company uses its best efforts to estimate what the cost of service would be if net metering customers produce no electricity (the "CFCOS" study). The Commission ordered that both the ACOS and CFCOS studies reflect costs and benefits at the system, state, and customer class levels. The second analysis segregates net metering customers in the ACOS study from the class in which they participate ("NEM Breakout COS" study). For

[1] Private Generation Long-Term Resource Assessment (2017-2036), Navigant Consulting, Inc., July 29, 2016, at 26. http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2017_IRP/PacifiCorp_IRP_DG_Resource_Assessment_Final.pdf

example, a separate residential net metering customer class is created in the cost of service study, which shows the impact net metering customers have on the residential non-net metering class and how well they recover the costs to serve them.

The Commission adopted this multi-part evaluation framework to fulfill the legislative requirements set in Utah Code § 54-15-105.1(1) ("Subsection One"). The Commission determined that, since Subsection One is intended to be useful for rate structure setting under Utah Code § 54-15-105.1(2) ("Subsection Two"), the analysis necessarily must be conducted in a manner and on a period commensurate with rate setting. By relying on the cost of service model, which is a key consideration in the development of rates for all customers, the Commission's framework is consistent with the legislative direction and provides practical results that will inform rate structuring.

Q. What are the results of implementing the evaluation framework directed by the Commission?

A. The analyses show that the current net metering program results in higher rates for other customers. Table 1 below summarizes the results of the comparison of the ACOS and CFCOS studies and shows that, for the Study Period, the net metering program increases costs to customers in Utah at the system, state, and class levels. Table 2 below summarizes the results for the NEM Breakout COS study. The direct testimony of Company witness Mr. Robert M. Meredith explains the inputs and presents the results of these analyses in more detail.

Table 1. Net Cost/(Benefit) of the Net Metering Program

	Cost (000)	Benefit (000)	Net Cost/ (Benefit) (000)
System Level	$5,010	($1,287)	$3,722
State Level	$5,010	($2,960)	$2,049
Residential	$ 3,540	$ (1,881)	$ 1,659
Schedule 23	$ 504	$ (405)	$ 100
Schedule 6	$ 673	$ (650)	$ 23
Schedule 8	$ 240	$ (395)	$ (155)
Schedule 10	$ 29	$ (21)	$ 7
Other Classes	$ 22	$ 393	$ 415
Total Customer Class Level	$ 5,009	$ (2,960)	$ 2,049

Table 2. Actual Cost of Service Results of Segregated Net Metering Classes

	Parity to Cost of Service		
	ACOS	ACOS W/O NEM	ACOS NEM
Residential	96.0%	96.1%	60.6%
Schedule 23	107.2%	107.3%	92.2%
Schedule 10	95.3%	95.1%	89.8%
Schedule 6	107.7%	107.7%	109.2%
Schedule 8	104.1%	104.0%	109.0%

These results show that, for the residential class, the current net metering program results in higher rates for other residential customers.

Q. Why does the net metering program result in higher rates for other customers?

A. The primary reason is because the revenue received from net metering customers does not cover the costs of serving them. This is shown explicitly in Table 2 where the net metering residential class is paying only about 61 percent of their cost of service. In contrast, the other residential class pays 96 percent of their cost of service. Mr. Meredith's Exhibit RMP__(RMM-1) shows that the net cost shifted to other residential customers from net metering is approximately $400 per year per residential net metering customer. This means that the rates for other residential customers are or will be increased to cover the costs incurred to serve residential net metering customers. The analyses take into account the unique characteristics of net metering customers and the value provided by their private generation systems. Despite the benefits created by their private generation systems, the current rate structure does not adequately recover the costs to serve them and essentially over-compensates residential net metering customers for their generation.

This result is largely caused by the fact that the current residential rate structure relies on recovering most costs through volumetric energy rates. As the results in Tables 1 and 2 show, the magnitude of the net metering cost shifting for the non-residential rate classes isn't as significant. This disparity is due to the difference in the rate structures between residential and non-residential rates that I will discuss later in my testimony.

Q. What is the potential impact of the cost shift to other residential customers if net metering is not addressed soon?

A. While the analysis for the 2015 Study Period shows a cost shift for residential net metering in Utah of $1.8 million under the NEM Breakout, extrapolating that level of cost shifting to current residential net metering participation as of October 7 of this year produces a cost shift of $6.5 million due to the rapid growth in installations. By 2020, the cost shift would be about $27 million per year based on the current growth projections. At the current net metering program cap of 923 MW (i.e., 20 percent of the 2007 peak load) set by the Commission in Docket No. 08-

035-78, the potential cost shift to other customers would be approximately $78 million annually. Over the next 20 years, the cumulative cost shifting related to residential net metering is estimated to be approximately $667 million.

In order to minimize this cost shift, the Company is proposing to close the current net metering program to new customers and to implement modifications to the program that will mitigate cost shifting while providing more appropriate compensation to net metering customers. In light of the adverse impacts on other customers, the Company is proposing net metering program and residential rate changes for customer generators in order to moderate future impacts.

Overview of Proposed Tariff Revisions

Q. Please summarize the Company's proposed tariff revisions to address cost impacts of the net metering program on other customers.

A. In conjunction with Tariff Advice No. 16-13, filed concurrently with this Compliance Filing, the Company is requesting approval of the following:

1. Revisions to Schedule 135, Net Metering Service, to close it to new service, effective after December 9, 2016;
2. Schedule 135A, Net Metering – Transition Service, effective after December 9, 2016;
3. Schedule 136, Net Metering Program, effective June 1, 2017, for modifications to the net metering program for applications received after December 9, 2016; and

4. Schedule 5, Residential Service to Customer Generators, effective June 1, 2017, for new rates to residential customers who submit applications for net metering after December 9, 2016, and are interconnected.

Exhibit RMP__(JRS-1) contains the proposed tariffs for Schedule 136 and Schedule 5. In addition to these tariff changes, the Company proposes changes to the application fees currently authorized by R746-312-13. The proposed application fees are based on the Company's experience and actual costs to process net metering applications. Exhibit RMP__(JRS-2) contains revisions to the interconnection agreements to update the application fee changes in this filing, as required by R746-312-17(1)(f).

Q. Please explain the Company's proposed tariff changes in Advice No. 16-13.

A. Advice No. 16-13 seeks modifications to Schedule 135, Net Metering Service, to close it to new service and to implement a new Schedule 135A, Net Metering – Transition Service. Schedule 135A mirrors the current Schedule 135 with the exception that it includes the following provision in the Availability Section:

> Customers will be subject to all changes to net metering service including changes to credits, charges or rate structures offered herein and in related tariffs resulting from the final determination under Utah Code Ann. § 54-15-105.1 which may include, without limitation, a transfer from this tariff to all new applicable service schedules approved by the Commission.

The Company proposes to have Schedule 135A in effect until the Commission makes a determination on Subsection Two of the Net Metering Statute and substantive modifications to the net metering program, which the Company seeks in the present Compliance Filing. The Company is proposing an effective date of December 10, 2016, for the tariff changes in Advice No. 16-13. The Company is requesting these tariff changes for Schedules 135 and 135A to provide interim service to customers that submit applications for net metering service under terms consistent with the current program.

Q. Why is the Company proposing the changes in Advice No. 16-13?

A. To mitigate potential cost shifts to other customers, the Company proposes to implement Schedule 135A as a transition tariff that will provide explicit notice to new net metering applicants that there may be changes to the service and rates for net metering customers following the conclusion of this proceeding. Without this transition tariff and notice, the Company would expect a significant groundswell of new program applications in the hopes that any program modifications would not apply to net metering customers for whom applications had been received or interconnections completed prior to the final Commission determination in this proceeding. The advice filing includes revisions to the standard interconnection and net metering service agreements to reference the tariff schedule change.

Q. Please explain proposed tariff Schedule 136.

A. Schedule 136 provides net metering service with modifications to address cost shifting as reflected in the results of the analyses directed by the Commission. As discussed by Company witness Mr. Gary Hoogeveen, since the costs of distributed generation, in particular rooftop solar photovoltaic, have significantly decreased over the last few years, incentives in the form of the current retail rates are no longer necessary. The specific changes to the program include:

1. A new provision that requires residential customers who participate in the net metering program to take electric service under the proposed Schedule 5, Residential Service for Customer Generators; and
2. Elimination of the option for large non-residential customers to receive compensation for excess generation at the average retail rate.

I address each of these in more detail below. The other features of the net metering program remain unchanged.

Overview of Schedule 5 - Electric Service for Customer Generators

Q. Please summarize the Company's proposal to implement a new rate schedule for residential customer generators, Schedule 5.

A. The Company is proposing a new rate structure for residential customer generators who participate in the net metering program under Schedule 136. The proposed rate structure will more directly capture the benefits these customers bring in rate setting as well as the costs, on both a class level and individual customer level, and will minimize cost shifting to other customers. Specifically, the Company is proposing a rate structure similar to that used for non-residential customers, comprised of a monthly customer charge, a peak demand charge, and an energy charge. Exhibit RMP_(JRS-3) and Table 3 below show the proposed rates for Schedule 5.

Table 3

Schedule 5 - Residential Service for Customer Generators		
		Proposed Price
Customer Charge		
	1 Phase	$15.00
	3 Phase	$30.00
Demand Charge		
	On-peak ($/kW)*	$9.02
Energy Charge		
	All kWh (¢/kWh)	3.8143
*On-peak periods with 60 minute interval:		
October - April 8:00 a.m. to 10:00 a.m.		
and 3:00 p.m. to 8:00 p.m.,		
May - September 3:00 p.m. to 8:00 p.m.,		
Monday-Friday, except holidays.		

Q. How were these rates calculated?

A. While the ACOS and CFCOS are useful for evaluating the impacts of the net metering program, the NEM Breakout COS study is more instructive in rate structuring under Subsection Two in the Net Metering Statute, as the Commission noted in its November 2015 Order.[2] Accordingly, the Company used the cost of service from the NEM Breakout COS study results presented in this filing and adjusted the results to the revenue requirement and current rates approved by the Commission in the Company's 2014 GRC. In this way, the new rates on Schedule 5 for customer generators are consistent with the revenue requirement and rates designed to recover that revenue requirement for all customers approved by the

[2] November 2015 Order, at 11.

Commission in the 2014 GRC. The NEM Breakout COS results are used as the starting point because they reflect the usage characteristics of the net metering class from the 2015 load research study. The adjustment process from the current cost of service study to the 2014 GRC is explained in more detail in Mr. Meredith's direct testimony.

Q. Why is the Company proposing this new rate schedule for only residential net metering customers?

A. As shown above, the cost of service analyses demonstrate that as a result of the large credit residential net metering customers receive through current rates for their excess generation, other customers' rates will increase in order to recover the same costs over fewer volumes. While the overall magnitude of the cost shifting is relatively small now, providing a separate rate schedule and a new rate structure for residential net metering customers will minimize the impact on other customers and reflect the different characteristics of residential net metering customers.

In addition, as Mr. Meredith's testimony shows, the cost shifting concern is less significant or even non-existent for non-residential classes. As I'll show later, the rate structures for non-residential customers already send better price signals and accommodate differences in load profiles for customers within the class, so costs are less likely to be under-recovered. For these reasons the Company is not proposing changes to the rate structures for non-residential net metering customers at this time. However, I do recommend elimination of the option for compensation at the average retail rate for excess energy for large non-residential customers, as discussed further below.

Q. How are the characteristics of residential net metering customers different from other residential customers?

A. Data from the Company's load research study for residential net metering customers, discussed in more detail in Mr. Meredith's testimony, shows that customers with on-site private generation have a different load profile than other residential customers, but not necessarily a different peak requirement. Figures 2 and 3 compare the profiles from the 2015 study. Figure 2 is the average annual hourly load and Figure 3 is the peak day.

Figure 2. Average Annual Load Profile of Residential and Residential Net Metering Customers

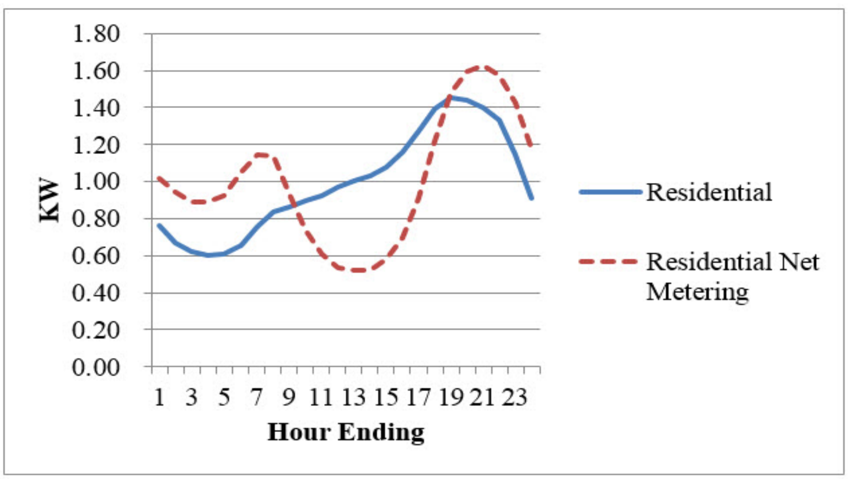
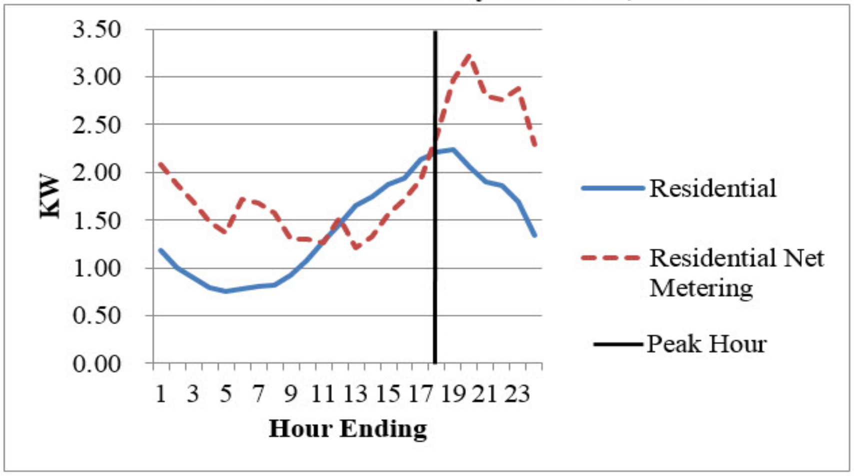


Figure 3. Load Profile of Residential and Residential Net Metering Customers on the Peak Day on June 30, 2015

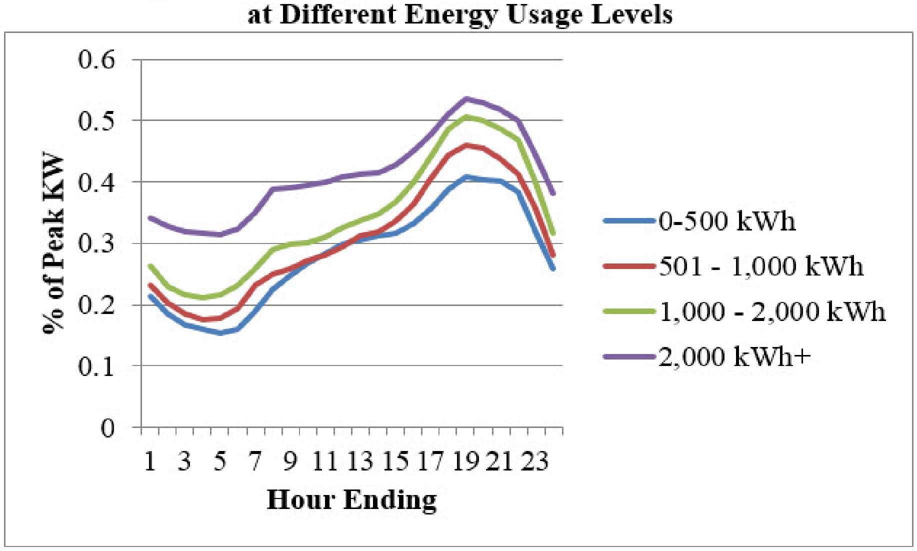


As Figure 2 shows, while net metering customers may take less energy (kWh) from the grid, their overall demand (kW) requirements from the grid may remain relatively unchanged. However, since costs associated with demand are recovered in the energy charges, net metering customers get credited for demand-related costs through the netting process for excess generation output, even though they continue to place a demand requirement on the system. In contrast to non-residential customer rate designs, the residential rate structure does not adequately capture the demand requirements placed on the system to serve these customers because it largely relies on energy charges. Net metering customers' usage also results in lower load factors for net metering customers compared to other residential customers. Lower load factors have more variability in usage and are more costly to serve than flatter, more consistent usage patterns.

Q. Aren't net metering customers similar to small use customers if they are partially served by their own generation?

A. No. Almost all net metering customers have solar private generation systems. The peak energy output of these solar systems occurs in the middle of the day prior to the timing of both the system and class level peaks. As a result of this output, the energy requirements for these customers are reduced, but the peak demand is either unchanged or reduced very modestly. This results in lower (less efficient) load factors for these customers. In contrast, the profile for all residential customers is very consistent between different energy usage levels. Figure 4 below shows a comparison of the profiles among different energy usage levels in the load research sample for all residential customers.

Figure 4. Average Annual Residential Load Profiles at Different Energy Usage Levels



In addition to lower load factors, residential net metering customers fundamentally use the system differently than low energy-use residential customers, since they use the energy grid not only to receive energy from the Company's facilities, but also to export excess energy that they produce to the

Company's system. Table 4 below shows the difference in average characteristics between residential customers with and without generation.

Table 4. Differences in Customer Characteristics

Characteristic	Unit	W/O Generation	With Generation	Difference
Energy Delivered	Average Monthly kWh	725	743	2.4%
Energy Exported	Average Monthly kWh	0	303	
Behind the Meter Energy	Average Monthly kWh	0	234	
Maximum Non-Coincident Peak	Average kW	7.13	11.05	55.0%
Customers per Transformer	-	6.34	4.12	-35.0%
Average Meter Cost	$	106.75	162.00	51.8%

Q. Please explain why demand costs are an important consideration in cost allocations and rate designs.

A. A customer class's demand requirements – the class's usage during the single hour of each of the system coincident peaks and state distribution coincident peaks – significantly influences cost incurrence and allocation. For instance, Table 5 below shows the difference in cost drivers in the cost of service study for the residential class in the ACOS and then the residential class in the NEM Breakout COS. Table 5 shows that over 60 percent of costs are allocated on demand-based measurements. Most of the Company's costs are allocated in class cost of service studies on demand-based measurements because the system is designed to serve load at different peaks.

Table 5. Residential Cost Allocation Drivers

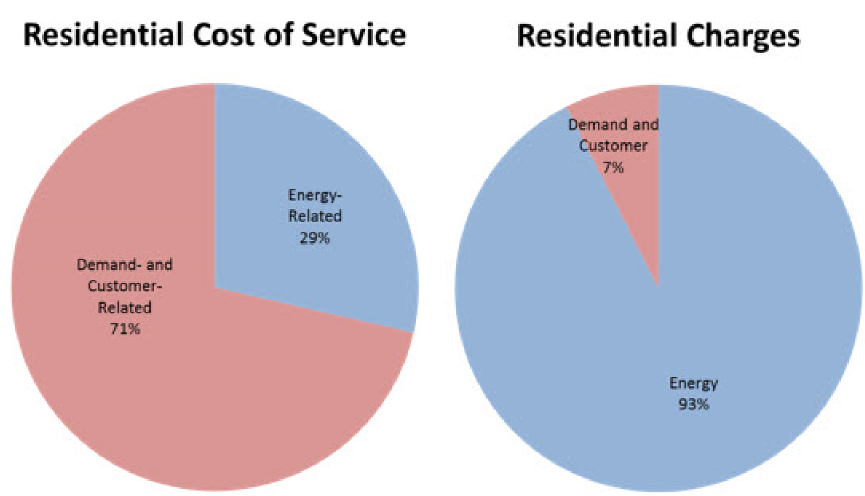
Allocation	All Residential ACOS	Residential Non-NEM ACOS Breakout	Residential NEM ACOS Breakout
Demand	62.9%	63.0%	64.8%
Energy	28.6%	28.6%	20.3%
Customer	8.5%	8.4%	14.9%

Q. Please elaborate on why providing a credit at the current full retail rate is problematic.

A. As the NEM Breakout COS study demonstrates (see Table 2 above), the cost of service results for residential net metering customers are different than the results for other residential customers; residential net metering customers contribute about 61 percent to the cost of serving them, compared to other customers who cover about 96 percent of the costs to serve them. This difference is due to the current net metering compensation approach, which provides a credit for a customer's private generation output at the full retail rate.

Currently, recovery of nearly all of the infrastructure costs for the electric system allocated to residential customers is achieved entirely through energy rates. Figure 5 below shows that while approximately 70 percent of residential costs are demand- or customer-related costs, over 90 percent of the revenue comes from variable energy-related charges.

Figure 5. Residential Cost of Service and Charges



As a result of current residential rate design, the credit that net metering customers receive for generation output in excess of their usage includes the costs for the infrastructure required to serve them. The residential retail rate ranges from 8.5 cents per kWh to 14.5 cents per kWh. In contrast, the Company purchases power from third-party developers through avoided cost pricing at less than 4 cents per kWh, so the purchase of excess output from net metering customers is more costly to other customers than if the Company had generated the energy itself or purchased it from a third party.

Proposed Rate Structure

Q. Please describe what is included in each of the proposed rate components for Schedule 5.

A. The proposed rates are comprised of the following costs:

- The monthly customer charge of $15.00 is designed to recover costs related to customer services and certain components of the distribution system, specifically service lines, meters, and line transformers. This customer charge assumes that the Commission adopts the Company's proposed application fee for Level 1 net metering customers, discussed later in my testimony. The Company proposes to recover the program administrative costs through a one-time application fee rather than through base rates. The customer charge would be higher if the administrative costs associated with handling applications is not recovered through a separate, one-time fee.
- The demand charge is designed to recover the remaining distribution-related costs (substations, poles and conductors) and the demand-related generation

and transmission costs. The demand charge would be applied against the customer's highest demand during a 60-minute interval during the on-peak periods. The Company is proposing to set the on-peak period from 3:00 p.m. to 8:00 p.m. during the summer months of May through September, and 8:00 a.m. to 10:00 a.m. and 3:00 p.m. to 8:00 p.m. in the winter months of October through April. The on-peak period is Monday through Friday, excluding holidays.

- The energy charge is designed to recover all remaining costs, which include net power costs.

Q. What are the advantages of this rate structure?

A. The proposed rate structure balances the regulatory objectives of customer understanding, cost causation, economic efficiency, revenue adequacy, intra-class equity, and inter-class equity. While a demand charge is a new element for residential customers, the Company is proposing a relatively simple structure that includes just three elements –-a customer charge, a demand charge, and an energy charge – in order to balance customers' ability to understand the new structure with cost incurrence. Since customer generators are typically more sophisticated energy customers, the concept of demand or system kW requirements should be understandable because kW is typically how private generation facilities are sized and purchased. Demand charges are a standard rate design element for non-residential customers already, however, the Company's proposed demand charge for residential customer generators includes several elements that will make it easier for residential customers to manage. The rate structure also reduces the likelihood that the system costs required to serve customer generators are systematically under-recovered and then shifted to other customers. The rate structure rewards higher load factor customers with a lower average rate, and better captures diversity within the class.

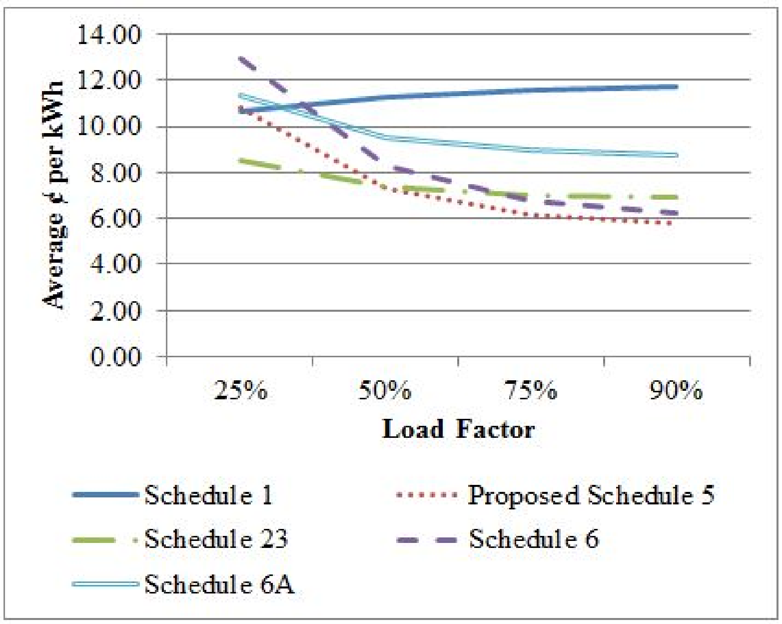
Q Will the rates provide a price signal to customers to encourage more efficient use?

A. Yes. Including an on-peak demand charge will send a better price signal to these individual customers than the current rate design because their rates will be in closer alignment with the different cost categories included in the cost of service study. Residential net metering customers will have an opportunity to reduce their bills by responding to these prices during the specific on-peak periods. The proposed demand charge sends a signal to both stagger and reduce appliance use during the peak period. In the short run, customers can modify their behavior so that their peak usage occurs at the same time as their generation. In the long run, customers can invest in resources that better match the timing of the peak usage. For example, they could install solar panels that are more westerly facing to produce more energy in the afternoon and early evening, which better aligns with the Company's peak, providing more benefit by reducing overall demand.

Q. Please provide an example of how the rates provide better price signals.

A. Unlike the rate structure for non-residential customers, the current residential rate structure with inclining energy rates directly rewards lower energy usage but not more efficient usage that helps to reduce overall system costs by also reducing demand. For residential customers, this signal to reduce overall demand is assumed to be an incidental or accompanying result of reducing overall energy usage. However, as I demonstrate above, net metering customers may reduce their energy usage but not their demand, resulting in becoming lower load factor customers. The proposed rate structure on Schedule 5 will better capture this change in usage and reward improving load factors to achieve a lower average rate. Figure 6 below shows the proposed Schedule 5 rates will provide lower average rates for higher load factor customers, similar to non-residential rate structures, to reward more efficient usage of the system.

Figure 6. Average Price Compared to Load Factor



Q. Please explain why $15.00 per month is a reasonable customer charge.

A. The Company is proposing to include the costs associated with customer services, meters, service lines, and transformers in the customer charge. These are essentially fixed costs and not subject to variability in customer usage.

Q. Why should transformers be included in the customer charge for Schedule 5?

A. Local distribution facilities such as transformers, poles, and conductors are facilities required to provide a residential customer access to electric service regardless of how much energy the customer uses. While this is true for all residential customers, net metering customers place additional burdens and reliance on these local facilities since they use them for both taking service from the Company and to export their excess generation output to the grid. The impacts of customer generation on the local distribution system, including transformers, are discussed in more detail in the testimony of Mr. Douglas L. Marx.

Accordingly, since customer generation relies on the local distribution system and can actually lead to additional costs to accommodate the output of excess energy onto the system, as discussed by Mr. Marx, it would not be appropriate to reflect local distribution costs in the energy credit received by net metering customers for excess energy. The Company proposes to include the cost of the transformers in the customer charge and the costs of the other local distribution facilities in the demand charge.

While the Company does not dedicate one transformer per customer, like meters and service lines that are included in the customer charge, the allocation approach in the cost of service study reflects the assumption that transformers are shared and a coincidence factor is used to recognize the diversity of usage that is considered with the initial sizing. In addition, a large portion of the cost of a distribution line transformer is associated with the equipment itself and does not vary with the capacity of the equipment. For example, a 25 KVA single phase pad-mount transformer and a 50 KVA single phase pad-mount transformer, which are commonly installed in residential subdivisions, have average installed costs of $4,700 and $4,827, respectively. Although, the 50 KVA transformer provides double the demand capacity of the 25 KVA transformer, it only costs about 3 percent more. Clearly, a large proportion of the costs of these transformers do not vary with capacity and are fixed infrastructure costs necessary to serve customers.

Q. Is the Company proposing a minimum bill in addition to the customer charge?

A. No. The Company is proposing only a monthly customer charge of $15.00 for Schedule 5 customers. All other charges on the bill will be subject to usage measurements.

Q. How did the Company calculate the demand charge and how will this charge apply to Schedule 5 customers?

A. The proposed demand charge of $9.02 per kW is designed to recover the costs of demand-related generation and transmission, which are allocated in class cost of service studies on system coincident peaks, and distribution substations and poles and conductors, which are allocated on distribution coincident peaks. The rate was calculated by dividing these costs by the kW usage during the proposed on-peak hours. The proposed on-peak periods are: 3:00 p.m. to 8:00 p.m. during the summer months of May through September, and 8:00 a.m. to 10:00 a.m. and 3:00 p.m. to 8:00 p.m. during the winter months of October through April. All weekends and holidays are excluded from the on-peak hours.

The charge would be applied to the customer's highest measured average kW usage during a 60 minute interval during on-peak times, during each billing cycle.

Q. How did the Company select the on-peak periods proposed for the Schedule 5 demand charge?

A. To determine the appropriate times under which the demand charge would apply, the Company examined the timing of both system coincident and distribution coincident peaks over the last five class cost of service studies filed with the Commission. This showed that most peaks occurred in the late afternoon/early evening timeframe in the summer months and both in the late afternoon/early evening and morning during the winter. In order to keep the rate design understandable and simple, the Company identified time periods that capture the vast majority of those peaks for both seasons. Additionally, the Company is proposing to use the same defined periods for Summer (May - September) and Winter (October - April) as current rates. The proposed on-peak periods include the timing of 94 percent of the peaks. Exhibit No. RMP_(JRS-4) shows the hourly occurrence of peaks in the Summer and Winter seasons and the on-peak period the Company selected for proposed Schedule 5.

Q. How does the proposed demand charge compare to demand charges for non-residential customers?

A. To moderate the impacts and make it easier for residential customers to respond to the price signal, the proposed charge is designed to apply over fewer hours, is measured over a longer interval, and is a lower charge than non-residential demand charges.

First, the proposed demand charge applies during a smaller window of time during the day compared to non-residential rates so that customers' energy management efforts can be more targeted to those hours. During Summer, for instance, customers need to pay attention to only 5 hours per day, from 3:00 p.m. to 8:00 p.m. In contrast, the Summer on-peak period for Schedule 6A is 16 hours, from 7:00 a.m. to 11:00 p.m., and for Schedule 8 it is 8 hours, from 1:00 p.m. to 9:00 p.m.

Second, to measure the kW usage, the Company proposes to take the average kW measurement over a 60-minute interval rather than the 15-minute interval used for non-residential customers. Averaging the usage over a longer period will help moderate impacts of sporatic appliance usage. For instance, Exhibit RMP_(JRS-5) shows an example of usage for a number of appliances during a 60-minute period. Taking an average over the 60-minute interval produces a demand measurement of 3.4 kW, whereas taking the measurement over the highest 15-minute interval produces a measurement of 6.3 kW.

Lastly, the proposed demand charge for Schedule 5 is considerably smaller than non-residential demand charges.

Q. Why is a time-based demand charge preferable to time-of-use energy rates for net metering customers?

A. If these demand-related costs were included in time-of-use energy rates, they would be included in the rates that customers are compensated for in their excess energy output due to the netting process. Since the customer's usage during the peak period contributed to these costs, these customers would be over-compensated for their excess energy and costs would continue to be under-recovered and shifted to other customers.

Q. Please discuss the proposed energy charge.

A. The energy charge recovers variable costs including net power costs and a portion of the generation and transmission investments (25 percent). The generation and transmission investment portion is consistent with the cost of service classification methodology adopted by the Commission. For customer generators, this energy charge better reflects the value of the excess kWh output by the customer facility. Under net metering, any excess kWh generated by the customer at one point in time will be offset against customer usage taken from the Company at another point in time. This energy charge more closely approximates the cost that the Company would have otherwise incurred in order to serve the customer and is a much more equitable compensation value to provide customer generators.

Q. Will the proposed rates on Schedule 5 still provide value to net metering customers?

A. Yes. Exhibit RMP__(JRS-6) shows the calculation of the average offset credit under the current and proposed rates for net metering customers. The average offset credit is the value in bill savings that customers receive for every kWh their generation produces. Currently, the Company provides to net metering customers, on average, an offset credit of 10.6 cents/kWh for their generation. Under the Company's proposed rates, net metering customers will receive an average offset credit of 7.1 cents/kWh. The proposed rates still provide considerable value to customer generation.

Q. Have you prepared examples of the potential bill impacts for net metering customers on Schedule 5 compared to current Schedule 1 residential rates?

A. Yes. Exhibit No. RMP_(JRS-7) shows the comparison between the amount customers currently pay at different usage levels compared to their bills under net metering service and the proposed Schedule 5 rates. This shows that an average net metering customer who uses approximately 1,000 kWh a month can still achieve bill savings between 9 percent and about 60 percent, depending on how much of their usage they are able to offset with their generation facility.

Q. Will the Company provide information to customers to help them understand the new rate structure on Schedule 5 and how they can better manage their usage?

A. Yes. The Company will work with interested parties to develop information for Schedule 5 customers to help them understand the rate structure and how changes in their usage will influence their bill.

Q. Will the Company allow current net metering customers on Schedule 135 to opt-in to net metering service on Schedule 136 and Schedule 5?

A. Yes. The Company will accommodate any current residential Schedules 135 and 1 net metering customer to transfer to Schedule 136 and Schedule 5. If a customer elects to transfer to Schedule 136, the customer will no longer be eligible to return to Schedule 135.

Modifications to Large Non-Residential Compensation Options

Q. Please explain the current compensation options for large non-residential net metering customers on Schedule 135.

A. Special Condition 2b in Schedule 135 provides the following options to large non-residential customers for the compensation of excess energy produced by customer generation facilities during a billing period:

(1) An Average Energy Price for the applicable calendar year according to the Volumetric Non-Levelized Prices shown in Schedule 37, weighted by season and on- and off-peak periods;

(2) A Seasonally Differentiated Energy Price for the applicable calendar year according to the Non-Levelized Prices shown in Schedule 37, weighted by on- and off-peak periods; and

(3) An average retail rate for the Electric Service Schedule applicable to the net metering customer as calculated from the previous year's Federal Energy Regulation Commission Form No. 1.

Q. What is the difference in the value of these options for 2016?

A. Table 6 below shows difference in the compensation credit for each of these options for 2016.

Table 6

Large Non-Residential Options	2016 Credit (¢/kWh) Baseload	Fixed Solar
Option 1. Average Sch 37 Price	1.8821	1.5991
Option 2. Seasonal Sch 37 Price		
Summer	2.0345	1.7515
Winter	1.8062	1.5232
Option 3. Average Retail Price		
Schedule 6	8.4498	
Schedule 6A	11.7871	
Schedule 6B	10.8910	
Schedule 8	7.5210	
Schedule 10	7.5619	

Q. Please explain the Company's proposed changes to the large non-residential options in the new Schedule 136.

A. The Company proposes to eliminate the third option of using the average retail price for excess energy from large non-residential customers. Table 6 above shows that the average retail rate credit option provides a credit far in excess of the avoided cost value that other small power producers would receive for the equivalent output. There is also a wide distinction on the compensation by rate schedule with customers on Schedule 6A getting 57 percent more for each excess kWh compared to Schedule 8 customers, even though there is no discernible difference in the value to the system for a kWh generated by a customer on Schedule 6A versus Schedule 8.

Not surprisingly, Option 3 is the option selected by all large non-residential net metering customers. In 2015, large non-residential customers were credited approximately $141,000 for their excess energy. This is 420 percent more than the avoided cost value under Options 1 or 2. In contrast to the avoided cost value, the average retail rate includes recovery of fixed costs typically collected through the monthly charge and demand charges. Accordingly and as I previously discussed in regards to residential customers, the average retail rate over-compensates non-residential customers for excess energy.

To create consistency between large non-residential customers and to be consistent with the value provided to other small power producers, the Company proposes to use Schedule 37 avoided costs prices for fixed solar facilities, under either Option 1 or 2.

Proposed Changes to Application Fees for Net Metering

Q. Please explain the Company's proposed changes to the application fees for net metering.

A. The Company requests that the Commission waive the fees adopted in rule R746-312-13[3] and approve changes in the fees, including adding a fee for Level 1 applications, as follows:

Table 7

Net Metering Application Fees		
	Current	**Proposed**
Level 1	0	$60
Level 2	$50	$75
per kW	$1.00	$1.50
Level 3	$100	$150
per kW	$2.00	$3.00

[3] R746-312-3(2) states: For good cause shown, the commission may waive or otherwise modify any provision of this electrical interconnection rule.

These fees are based on an assessment of the actual costs incurred to process applications. Recovery of the costs to process the applications for net metering, particularly for Level 1, has not kept pace with the growth in applications. The modest increases in fees represent movement toward recovering the administrative costs incurred to process applications and make cost recovery more concurrent with expense.

Q. How were the current application fees established?

A. The current fees were established by the Commission in the rulemaking initiated in 2009, Docket No. 09-R312-01, to implement standards for interconnection of electric facilities in Rule R746-312, Electrical Interconnection. These rules establish the terms and conditions upon which a customer may interconnect a generation facility to the distribution system and the review process for the utility to ensure that the interconnection will be consistent with these terms and conditions. The rules identify three potential levels of review, based on the size of the facility to be interconnected as well as the complexity of the review – Level 1 for facilities 25 kW and smaller, Level 2 for facilities greater than 25 kW or that do not otherwise qualify under Level 1, and Level 3 for facilities that do not otherwise qualify under Levels 1 or 2 and require a more complex review. Mr. Marx outlines the administrative process for net metering applications in his direct testimony.

Q. How did you calculate the proposed fees requested in this filing?

A. The Company reviewed the actual costs incurred to process applications in 2015, the number of applications completed for each level, and the allocation of these costs by rate schedule. The allocation by rate schedule is discussed in the testimony of Mr. Meredith. Exhibit RMP_(JRS-8) shows the breakdown by level and rate schedule of applications processed during 2015. Out of about $560,000 in costs to process the applications, the Company recovered only about $17,000 in fees from Level 2 and Level 3 applications. Because the vast majority of applications, about 99 percent, are Level 1, the majority of the costs are related to Level 1 applications.

To better balance cost incurrence with recovery, the Company is proposing a Level 1 fee along with increases in the fees for the other levels. Since the majority of Level 1 applications are for residential customers, the calculation of the Company's proposed Level 1 fee was based upon the average cost of processing a residential net metering application, which was about $60. Applying the $60 fee to all Level 1 applications would have produced about $474,000 of application fee revenue or about 85 percent of the total $560,000 cost to process applications in 2015. The addition of a Level 1 fee removes about $443,000 out of the costs included in proposed rates for Schedule 5. These one-time costs are more appropriately recovered through a one-time fee rather than embedded into rates. If the net metering application-related costs were alternatively recovered through the basic charge on Schedule 5, the proposed basic charge would be higher by $8.41 per month.

To gradually move towards better recovery of all net metering application fees, the Company proposes a uniform 50 percent increase to Level 2 and Level 3 application fees. For Level 2, the Company proposes a $25 increase to the charge per application and a 50 cent increase to the per kW charge. For Level 3, the Company proposes a $50 increase to the charge per application and a one dollar increase to the per kW charge. Increasing the application fees will reduce the costs needed in rates for other customers and retain the proportional relationship between the fees by level, without creating a barrier for participation. Based on the 2015 costs, these increases are still conservative and will encourage the Company to find efficiencies in the administrative process.

Deferral for Incremental Revenue from Schedule 5

Q. Would approval of the proposed tariff changes in this filing result in an over-collection of revenues to the Company?

A. No. The Company is proposing to apply the changes to only new net metering customers that file applications after approval of Schedules 136 and 5. Since the current number of net metering customers exceeds the assumed number of net metering customers included in the forecast in the 2014 GRC by over 600 percent, current rates do not reflect the costs of serving these customers. Accordingly, the Company is absorbing the costs of net metering for current customers. The Company will continue to absorb these costs until a new rate case is filed and the costs can be captured in rates to other customers. Approval of the new Schedule 5 would reduce the growing impact that will be eventually captured in rates.

While the Company does not expect the new structure to result in an increase in income for the Company, it will result in the higher revenues than would otherwise be achieved as a result of better reflecting the cost to serve net metering customers. To minimize the future impact on other customers, the Company proposes to defer the difference in revenue associated with the new rates on Schedule 5. In this way, the filing will be revenue-neutral for the Company.

Q. Please explain how the proposed deferral would work.

A. For new residential net metering customers, the Company would calculate the difference in revenues between current rates and Schedule 5 rates based on actual billed usage. This difference could be higher or lower for each customer. At the time of the Company's next rate case, the Company would make a proposal for amortization of the deferral balance.

Q. Does this conclude your testimony?

A. Yes.