ROCKY MOUNTAIN POWER
A DIVISION OF PACIFICORP

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July 25, 2017

VIA ELECTRONIC FILING
AND OVERNIGHT DELIVERY

Utah Public Service Commission
Heber M. Wells Building, 4th Floor
160 East 300 South
Salt Lake City, UT 84114

Attention: Gary Widerburg
Commission Secretary

RE: Docket No. 14-035-114 - In the Matter of the Investigation of the Costs and Benefits of PacifiCorp's Net Metering Program
Rebuttal Filing

Pursuant to the Amended Scheduling Order issued by the Public Service Commission of Utah ("Commission") in this docket on July 14, 2017, Rocky Mountain Power hereby submits for filing its rebuttal written testimony. The filing consists of the rebuttal testimony and exhibits of five witnesses.

Rocky Mountain Power respectfully requests that all formal correspondence and requests for additional information regarding this filing be addressed to the following:

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Sincerely,

Jeffrey K. Larsen
Vice President, Regulation

cc: Service List - Docket No. 14-035-114

CERTIFICATE OF SERVICE

I hereby certify that on July 25, 2017, a true and correct copy of the foregoing document was served by email on the following Parties in Docket No. 14-035-114:

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Rocky Mountain Power
Docket No. 14-035-114
Witness: Gary W. Hoogeveen

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

Rebuttal Testimony of Gary W. Hoogeveen

July 2017

Q. Are you the same Gary W. Hoogeveen who presented direct testimony in this proceeding?

A. Yes I am.

Purpose of Rebuttal Testimony

Q. What is the purpose of your rebuttal testimony?

A. I address various policy arguments raised by intervenors in their direct testimony. Specifically, I refute the claim by some that Rocky Mountain Power's proposed rate structure would eliminate customer choice. As discussed below, the Company's proposal preserves customer choice and customers' ability to generate power for their own consumption. This proposal also continues to allow customers to sell privately generated energy back into the system through net energy metering ("NEM") in a manner that is fair to all customers. This filing more accurately aligns the costs and benefits of serving the energy needs for those customers who choose to participate in NEM so that non-participating customers do not bear an increasing share of the fixed costs of the overall electric system. We recognize customers elect to generate their own energy for various reasons. At the same time, however, those customers should pay for the full cost of their service and should not be subsidized by other customers, particularly by those who cannot afford increased energy costs.

In this filing, we ask the Commission to fairly determine the cost of service for private generation customers. I also address intervenor claims that the Company's proposal upsets free markets, is anti-competitive, and would end the rooftop solar industry in Utah. Next, I respond to claims that the NEM framework the Commission has selected excludes long-term benefits, and that adoption of the Company's proposal will result in significant job losses in the rooftop solar industry. Finally, I address certain concerns raised in the public setting based, in large part, on misinformation.

Q. Do you agree with intervenors' claims or insinuations that the Company's proposal will eliminate customer choice for solar in Utah?[1]

A. No. Rocky Mountain Power supports customers who want to generate a portion of their own energy. Any customer who chooses to install solar panels on their roof has a right and opportunity to do so. This issue arises in the current NEM structure because it allows NEM customers' choice to harm non-participating customers. First, the current framework results in NEM customers paying less than their cost of service, increasing costs for non-participating customers to maintain the network. Second, because of the netting, non-participating customers are paying NEM customers the retail volumetric rate for excess power when that energy is available at much lower wholesale prices. To be clear, the Company is not seeking to eliminate rooftop solar as an option. But customers' choice to take and pay for Company power only should be equally protected and they should not have to subsidize NEM customers. Customers can decide whether to install rooftop solar after fully analyzing the economics of rooftop solar without subsidies, even if it is uneconomic, provided that the cost of making that choice does not impose costs on other customers.

[1] Vivint Solar witnesses Thomas Plagemann, Direct Testimony, ll. 246-7 and Richard Collins Direct Testimony, ll. 107-13; Vote Solar witness David DeRamus, Ph.D., ll. 215-31; and, Utah Clean Energy witness Melissa Whited, ll. 119-40.

Q. How does the Company's proposal preserve choice and ensure costs are appropriately allocated among its customers?

A. The Company's proposal recognizes that, under the status quo, non-participating customers are currently paying a portion of the costs to support the system for NEM customers. Our proposal would rectify this so that customers keep their choice to participate in NEM, without being subsidized by customers who simply want lower cost, safe and reliable electricity provided by the utility.

Q. Some intervenors imply that as a policy matter the Company must subsidize rooftop solar in order to provide environmental or job benefits to the state.[2] Do those policies justify long-term preservation of the current NEM structure?

A. No. Rocky Mountain Power purchases energy from Utah solar farms at one-third the price it pays NEM customers for the same power. Both generation sources (commercial solar and rooftop solar) produce jobs in the solar industry. Proponents of both sources claim they are helping the environment. Both generation sources use the grid to transfer that power to customers. The key difference between these generation sources is that the cost to customers is three times more for the electricity exported by NEM customers. This is unfair and needs to change. Our proposal actually fosters a free market for energy pricing rather than forcing Utah's electricity customers to pay triple the wholesale market price for energy exported to our system.

Q. How should the status quo change to achieve market parity?

A. A private generation customer should be paid for the exported energy at a rate that is

[2] Plagemann Direct Testimony, ll. 241-56 and Collins Direct Testimony, ll. 186-204; Sierra Club witness Allison Clements, Direct Testimony, ll. 55-66, 790-803, 887-99, 976-82; DeRamus Direct Testimony, ll. 76-84, 323-24, 371-78, 1233-35, 1324-40.

competitive with what customers pay other energy resources, instead of the current retail rate. We don't propose paying them less than market value for that energy—we just don't believe our non-participating customers should pay them a subsidy. As further explained by Company witnesses, the data show that the average private generation customer currently receives approximately $400 per year in subsidies (including administrative, engineering, and metering costs) from other customers.

Private generation and rooftop solar in particular, is here to stay. Because rooftop solar has been fostered now for fifteen years and will likely continue to grow as technology costs decline, it is time for a sustainable, long-term solution that balances the costs and benefits for all customers. A fair and balanced solution is achievable while maintaining Utah's low energy costs, which are among the lowest in the nation. The Company's request is simple. All customers should pay the cost for the energy they use. Second, if a private generation customer exports excess energy, that customer should receive market value for that energy.

Q. Certain intervenors claim the Company's proposed structure is intended to eliminate competition and protect the Company's bottom line.[3] How do you respond to this claim?

A. This argument mischaracterizes the Company's proposed structure and ignores the problems with the current NEM structure. Some have conflated the issue of market-share with unfairly transferring costs of service to other customers. This simplified rhetoric fails to acknowledge established utility ratemaking principles. The current NEM program burdens non-participating customers with subsidies that result in higher

[3] Collins Direct Testimony, ll. 100-6, 109-13 and Plagemann Direct Testimony, ll. 222-5; HEAL Utah witness Jeremy Fisher, p. 12.

costs for them. This inequity allows a private generation customer to avoid paying the cost of using the system by offsetting usage at the retail rate.

Regarding the false claim that the Company's intent is to protect its bottom line, the proposed deferral ensures our proposal is earnings-neutral. The Company's proposal seeks only to stop one group of customers from shifting a portion of their costs to a different group of customers. Because the Company is allowed to recover its prudently incurred costs in either instance, the issue is one of fairness and parity among our customers.

Q. Are there other factors that exacerbate the inaccurate market signals that arise from the current NEM program?

A. Yes. In addition to these inaccurate price signals, misinformation circulated in the market has created significant customer confusion. For example, reproduced below is a portion of a flyer circulated by the Sierra Club, produced in response to a data request in this proceeding:

The Problem

Utah's monopoly utility Rocky Mountain Power wants to restrict our freedom to choose how to power our homes and businesses by stifling the growth of affordable, homegrown clean energy solutions like rooftop solar. Our state's solar industry should be allowed to compete fairly in the free market, but Rocky Mountain Power continues to fight free enterprise by trying to stop Utahns from generating their own electricity.

The Solution

Utahns from all walks of life should have the right to choose clean energy solutions like rooftop solar while being compensated fairly for the power they produce and for the benefits they bring to the grid. We must push back against regressive demand charges for any and all customers, recognizing that demand charges take control of utility bills out of the hands of customers and hurt low-income utility customers the most.

The Benefit

According to the Department of Energy, there are already more than 3 times as many jobs in Utah in the clean energy and energy efficiency industries (over 37K) than there are in the fossil fuel industry, both generation and fuel production (nearly 12K). The entire Utah solar industry employs more than 5,894 workers across Utah. Those jobs will continue to grow if we can protect our rooftop solar program from Rocky Mountain Power's attacks.

The Call to Action

Let's protect energy choice -- Don't let an out-of-state-owned monopoly utility destroy our growing rooftop solar industry just so they can make a bigger profit. See the reverse side for actions!

Among other things, this flyer misstates the issues by claiming the Company's proposal restricts customers' freedom of choice, doesn't allow the solar industry to compete in the free market, that demand charges are regressive for any and all customers and hurt low-income the most, and asserts that the Company is simply motivated by a "bigger profit." This kind of misinformation about how NEM operates and the market impact of NEM is counter-productive to proper price signals that drive free markets. In contrast, the flyer fails to disclose that NEM provides a subsidy in the form of an above-market price to private generators at a cost to other customers, that demand charges are widely used for all other customers, or that the Company proposed a deferral in this docket to capture and return to other customers any additional revenues that may arise from the proposed rates in this proceeding.

Q. A number of intervenors contend that the Company's proposal would "wipe out" the solar industry.[4] How do you respond to that contention?

A. This contention is misguided and ignores the Commission's role, which is to establish just and reasonable rates. The rooftop solar industry should stand on its own without subsidies from customers. Customers who want to participate in private generation have the right to continue to do so under the Company's proposal; we simply ask them to pay the <u>actual cost</u> of service with an appropriate compensation for energy they deliver to the grid—no more, and no less. This approach is consistent with the Utah legislature's recent decisions on solar tax credits, which recognized the need to phase out subsidies for the solar industry.[5] The rate structure approved by the Commission should reflect those determinations by eliminating the subsidies for rooftop solar that are paid by non-participants. The Net Metering Statute requires the Commission to evaluate the costs and benefits of net metering and then to set just and reasonable rates for NEM customers, not rates that create a profit for an industry segment at the expense of our customers.

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[4] Vivint Solar witnesses Dan Black Direct Testimony, ll. 49-51, and Plagemann Direct Testimony, ll. 243-52; Utah Clean Energy witnesses Tim Woolf Direct Testimony, ll. 162-6 and Whited Direct Testimony, ll. 121-9; Vote Solar witness Rick Gilliam Direct Testimony, ll. 413-16; Clements Direct Testimony, ll. 621-31.

[5] House Bill 23 (2017 Legislative Session), available at https://le.utah.gov/~2017/bills/static/HB0023.html; *see also* the following article in the Salt Lake Tribune: http://www.sltrib.com/home/4891725-155/solar-industry-drops-fight-over-tax.

Q. What is your response to Mr. Fisher's assertion that the NEM Studies purportedly demonstrate the Company's existing resources and those planned in its IRP are uneconomic?[6]

A. As an initial matter, Company witness Robert M. Meredith provides a rebuttal of Mr. Fisher's assertion and analysis so I will not repeat his arguments here. But it is important to note that comparing private solar generation with base load resources is not a fair comparison. The Company has an obligation to serve its customers and relies on its system resources to meet that obligation. It cannot rely on intermittent resources alone to meet that obligation. In contrast, NEM customers have no obligation to serve. They remain connected to the grid, and can draw on that power as they see fit, with any exported power being simply incidental to their usage. Mr. Fisher's analysis also ignores that private solar generation is not subject to the same prudence or reliability standards, contractual obligations, or other similar requirements of utility-acquired and -operated resources. While Mr. Fisher argues that rooftop solar provides various long-term benefits, his analysis assumes that no such benefits are provided by the Company's other resources. That is wrong. Finally, this Commission previously ruled in this case that rooftop solar is not a resource factored into the Company's resource portfolio.[7]

Q. Some intervenors argue that the Company's proposal will lead to significant layoffs in the rooftop solar industry.[8] Does the Company have a position on this issue?

A. Yes, the Company's proposal is not an attack on any industry, nor is it intended to cause

[6] Fisher Direct Testimony, p. 6, ll. 8-12.
[7] Docket No. 14-035-114, Order at 13(November 10, 2015).
[8] Collins Direct Testimony, ll. 186.

layoffs. The Company's proposal is in response to the NEM Statute and the Commission's prior orders in this docket. It is the result of the NEM Studies, and seeks to rectify the cost shifting those studies demonstrate is occurring. Intervenor arguments regarding potential impacts of this proceeding on the jobs in the solar industry incorrectly assume it is the Commission's statutory role to ensure job levels of the solar industry are maintained. There is no support in the NEM Statute or the Commission's prior orders for this assumption. Indeed, the opposite is true. The Commission has previously ruled that the NEM Statute requires the Commission to consider only costs that accrue to the "electrical corporation or other customers" rather than "some broader group."[9] It rejected claims that other considerations, including "labor market conditions," should factor into its analysis.[10] As the Commission noted, such considerations are outside the scope of the NEM Statute:

> We find nothing . . . suggesting the legislature desired the Commission to conduct an all-encompassing analysis that extends to the kinds of broad societal concerns Intervenors assert are relevant in this docket. Indeed, Intervenors' interpretation would require the Commission to act as a *de facto* legislative body, weighing all societal benefits and costs and attempting to assign some value to them without direction from the legislature as to how competing interests ought to be prioritized and no matter how attenuated they may be from the business of the electric utility which it is the Commission's essential function to regulate. We are not persuaded the legislature intended the Commission to undertake such an unprecedented analysis, which would significantly extend the Commission's regulatory purview from the business of public utilities to, essentially, the entire arena of public policy.[11]

In addition, intervenor arguments about the potential impact of this proceeding on solar

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[9] Docket No. 14-035-114, Order Re: Conclusions of Law on Statutory Interpretation and Order Denying Motion to Strike, at 12 (July 1, 2015).
[10] *Id.* at 13.
[11] *Id.* at 14-15.

jobs fail to acknowledge the impact subsidies and excessive reimbursement rates have had on those same jobs. The cost of rooftop solar energy is three times the cost of solar energy provided in the market. Thus, if intervenors were correct that the Company's proposal would result in a reduction in jobs, they would also have to concede that the current excessive rate paid for exported power (together with the other subsidization received by NEM customers) is artificially inflating the number of solar jobs and artificially reducing the number of jobs in the remaining solar generation industry that is operating without such advantages. Also, if the Commission implemented rates to sustain jobs in the rooftop solar industry, it would necessarily be harming jobs in other industries that compete with that industry—commercial solar, hydro, wind, geothermal, coal, natural gas, and so on.

Further, in no other instance does the Commission factor into its rate determinations the impact those rates could have on the employment rate in a particular industry. Intervenors have provided no justification for why such considerations should factor into this proceeding, and there is none. The Commission's duty is to ensure that customers are receiving power at just and reasonable rates. To do otherwise sets a dangerous precedence for utility rates to become a bail-out mechanism for troubled industries.

Finally, the Commission has already determined that only costs or benefits that are "subject to quantification and verification" and that relate to "the utility's cost of service" are to be considered.[12] This includes references to actions or events in other states. As the Commission has previously ruled in this docket, out of state actions or

[12] *Id.*, at 16.

events "[have] little probative value," and, as a result, evidence of claimed costs or benefits must be proven relevant and valuable "on [their] own merit."[13] Intervenors have provided no Utah-specific evidence that demonstrates the solar job market will be significantly impacted by the Company's proposal as opposed to other market factors.

Q. The Division of Public Utilities ("DPU") and the Office of Consumer Services ("OCS") propose that the Commission lower the cap on the NEM program and implement a new program to support private generation with a separate compensation rate for exported energy. They propose that the Commission initiate a new proceeding to develop a methodology or formula for calculating the compensation rate.[14] What is the Company's position on these proposals?

A. As explained in more detail in the rebuttal testimony of Joelle R. Steward, the Company agrees with the DPU and OCS and would support moving to a new program that would separately provide compensation to private generation customers for the power they export to the grid outside the retail rate netting. This approach would provide for a more transparent and consistent treatment of energy purchases by the Company on behalf of customers and establish appropriate market signals. To provide more stability for customers and the solar industry, the Company recommends that the Commission take steps now to move to this new model.

Q. How do you respond to many in the public who oppose any change to NEM rates based, in large part, on misinformation?

A. Rocky Mountain Power celebrated its 100th anniversary serving Utah customers about

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[13] *Id.*, at 16-17.

[14] Division of Public Utilities witness Artie Powell, Ph.D., Direct Testimony, ll. 454-528, and Office of Consumer Services witness Michele Beck Direct Testimony, ll.337-653.

five years ago. We have provided our customers with reliable, low-cost power for many, many years and are proud of our service and our partnership with our customers. There is no basis for the assertion that the Company is seeking to undermine the solar industry. Instead, the Company seeks proper and fair allocation of costs between NEM customers and other customers. Contrary to popular belief, the Company's generation portfolio is not reduced by rooftop solar. It is also not true that rooftop solar saves all customers money. The Company's NEM Studies show that the costs of NEM actually exceed its benefits, and other customers are paying the average rooftop solar customer $400 per year through the NEM subsidies. In the aggregate and if the NEM program is left unchanged, this will result in a cost shift totaling over $650 million over 20 years. The Company strives to protect the air and water and complies with its environmental requirements, but such considerations cannot be factored under the NEM Statute in determining a just and reasonable rate for NEM. Finally, the Company's proposal would not result in fewer choices for customers. The Company supports each customer's right to choose for themselves whether they want to pay for rooftop solar or receive all power from the Company. Adoption of the Company's proposal would not eliminate that right. However, it would result in rates that more fairly reflect the costs of serving NEM customers and the benefits they provide.

Q. Does this conclude your rebuttal testimony?

A. Yes.

Rocky Mountain Power
Docket No. 14-035-114
Witness: Joelle R. Steward

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

Rebuttal Testimony of Joelle R. Steward

July 2017

Q. Are you the same Joelle R. Steward who presented direct testimony in this proceeding?

A. Yes I am.

Purpose and Summary of Rebuttal Testimony

Q. What is the purpose of your rebuttal testimony?

A. My rebuttal testimony is comprised of three sections. In Section I, I respond to the direct testimony submitted by other parties on June 8, 2017, related to the Company's proposed changes to the net metering program and new rates for net metering customers. Specifically, I respond to testimony submitted by the Division of Public Utilities ("DPU") witnesses Dr. Artie Powell and Stan Faryniarz; the Office of Consumer Services ("OCS") witnesses Michele Beck, James Daniel, and Danny Martinez; the Energy Freedom Coalition of America ("EFCA") witness Eliah Gilfenbaum; Utah Clean Energy ("UCE") witness Melissa Whited; Vote Solar witnesses Dr. David DeRamus and Rick Gilliam; Vivint Solar witnesses Thomas Plagemann and Richard Collins; and Sierra Club witness Allison Clements.

In Section II, I present the Company's revised rate design proposal. The revised rate design proposal includes optional energy-based time-of-use ("TOU") rates in addition to the demand-based time of use rates.

In Section III, I discuss a succession program to net metering.

Q. Please summarize your general observations from the other parties' direct testimony.

A. The majority of parties appear to recognize that net metering ("NEM") as we know it today is not sustainable in the long-run, or that at least some level of change is warranted, particularly related to how exported energy is compensated. There is, however, a wide difference of opinion on the timing and scope of necessary change. The DPU and the OCS, who concur with the Company's findings from the compliance analysis that the costs of NEM exceed its benefits, recommend that the Commission lower the cap on the NEM program in this proceeding and move to a new program model. For the new program, they recommend that the Commission initiate a new proceeding to develop a formulaic rate to compensate customers for exported power from on-site generation while giving different treatment to rates for energy consumed from the grid.[1] While not going as far as the DPU and OCS in their recommendations, many of the other parties implicitly acknowledge that the current NEM program is problematic, particularly the export rate.[2] EFCA, for instance, argues that the value could be higher than the retail rate.[3] Many parties also cite the contentious debates that have been occurring around the country related to proposed changes to net metering and the ensuing uncertainty and confusion for all stakeholders.[4] In all, the parties' arguments demonstrate the need for clear direction from the Commission on changes to the current ratemaking model for customers with private generation, and the timing for the changes. While the Company supports the recommendation of the DPU and

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[1] OCS witness Michele Beck Direct Testimony, ll. 323-433; DPU witness Artie Powell, Ph.D. Direct Testimony, ll. 454-582.

[2] *See e.g.*, EFCA argues that adjusting the export rate may resolve the Company's concerns requiring a separate class. EFCA witness Eliah Gilfenbaum Direct Testimony, ll. 414-20. UCE recommends that, if a change in the NEM program is necessary, compensation for excess generation should be reduced. UCE witness Melissa Whited Direct Testimony, ll. 559-63. Vivint proposes an alternative that would step down the value for exported energy. Vivint Solar witness Thomas Plagemann Direct Testimony, ll. 281-3. Vote Solar proposes a declining compensation rate for net excess energy to address the Company's concerns about cost shifting. Vote Solar witness Rick Gilliam Direct Testimony, ll. 760-3.

[3] Gilfenbaum Direct Testimony, ll. 483-9.

[4] *See e.g.*, Sierra Club witness Alison Clements Direct Testimony, ll. 690-982. Plagemann Direct Testimony, ll. 32-47. Vivint Solar witness Dan Black Direct Testimony, ll. 112-38.

OCS to lower the cap on the NEM program and begin the transition to a new program now, which I discuss in more detail in Section III, the majority of my rebuttal testimony specifically addresses the NEM program that is the subject of this proceeding, and the Company's proposed changes to that program to minimize cost shifting.

Q. Please summarize your rebuttal testimony.

A. In Section I, I continue to support the need for a separate class and rate design for residential NEM customers in order to eliminate the cost shifting that occurs and to send correct price signals. I show that other parties' attempts to argue that the data does not support a separate class are without merit. For the proposed rate design, I rebut the arguments that transformers should not be included in the customer charge, that a minimum bill provides a solution to cost shifting, that demand charges are inappropriate, and that the proposed rates will result in unacceptable bill increases for NEM customers. I also continue to support the need for elimination of the average retail rate option for large non-residential customers, showing that the average retail rate option is in excess of benefits. Regarding the Company's proposed application fees, I continue to support the proposed $60 fee for Level 1 interconnections, which no party opposed, but withdraw the request for increases in Level 2 and 3 interconnection fees at this time. Lastly, I provide additional details on the Company's proposed deferral for incremental revenue from Schedule 5.

In Section II, I present updated rates for residential NEM customers. In addition to the time of use demand-based rates I presented in my direct testimony, I propose an optional TOU energy-based rate for NEM customers. The TOU energy-based rate option includes a $28 per month customer charge in order to better track costs. For the

TOU demand-based rate, the customer charge has been updated to $13 per month, based on the updated cost of service results presented by Company witness Robert M. Meredith.

In Section III, I support the proposal by the DPU to lower the cap on the current NEM program and develop a new successor program for private generation. The new program would provide a separate compensation rate for all exported energy.

I. Rebuttal of Other Parties Direct Testimony

Q. Please explain how your rebuttal of other parties' direct testimony is organized.

A. I organized this section around the issues I addressed in my direct testimony:

- Whether residential NEM customers should be in a separate class;
- Rate design for residential NEM customers;
- Non-residential excess energy credits;
- Proposed application fees; and
- The proposed deferral for any incremental revenues from the proposed residential rate design.

<u>NEM Customer Class</u>

Q. Please summarize other parties' positions on whether residential NEM customers should be in a separate rate class.

A. DPU witnesses Dr. Powell and Mr. Faryniarz present analyses on differences in usage characteristics of residential NEM customers compared to non-NEM customers, and argue that these differences may not conclusively support the need to establish residential NEM customers into separate class today.[5] However, the DPU identifies

[5] Powell Direct Testimony, ll. 58-61; DPU witness Stan Faryniarz Direct Testimony, ll. 90-4.

aspects of NEM that indicate a separate class may be important.[6] The OCS agrees with the Company that NEM customers have different usage characteristics than other residential customers, but does not believe it is necessary to create a separate NEM customer class.[7] EFCA, USEA, Vote Solar, and UCE oppose the creation of a separate class for NEM customers, arguing that the behind-the-meter reduction should be treated similar to other types of energy efficiency, that analysis excluding crediting shows similar usage as non-NEM customers, and that the differences are no more significant than the differences between other intra-class subsidies that occur.[8]

Q. How do you respond to the DPU's testimony?

A. I appreciate the additional statistical analysis the DPU has contributed to the record; however, unlike the DPU, I find the DPU's analysis supports the creation of a separate residential NEM class now, particularly when considering that residential NEM customers significantly underpay the costs of serving and therefore shift costs to other customers. In addition, NEM customers fundamentally use the system differently—to back-up their own generation, akin to partial requirements customers, and to export the generation that exceeds their immediate needs. As such, changing the current structure by creating a separate class for NEM customers is in the public interest.

Q. How do the DPU's usage and cost of service characteristics analyses support the creation for a separate residential NEM class?

A. First, Dr. Powell presents analyses that confirm that:

(1) The customer profiles between residential NEM and non-NEM are distinct

[6] Powell Direct Testimony, ll. 272-80.

[7] Beck Direct Testimony, ll. 70-4.

[8] *See e.g.*, Gilfenbaum Direct Testimony, ll. 51-5, 374-420. Whited Direct Testimony, ll. 51-4, 357-62. Stanley Direct Testimony, ll. 197-210. DeRamus Direct Testimony, ll. 85-101. Gilliam Direct Testimony, ll. 661-72.

(1) ... despite the similarity of their average usage;

(2) The rate of change in usage by NEM customers during the day is significantly larger than non-NEM customers;

(3) The variation in load factors for NEM customers is greater; and

(4) NEM customers have notably lower load factors.[9]

These markers indicate that residential NEM customers have different characteristics or, at the very least, that differences in rate design treatment may be warranted to better address these differences among customers.

Second, Dr. Powell notes that separating NEM customers from the residential class may better capture the benefits NEM customers bring to the system, allowing the design of their rates to reflect those benefits.[10] In this regard, Table 1 below shows the differences in the unit costs by function between non-NEM and NEM residential customers. NEM customers have an overall lower cost of service, particularly in the generation and transmission functions, once the one-time program administration costs are removed. Accordingly, these lower costs would be passed on to NEM customers through lower rates in a separate class rather than diluted as part of the larger residential class.

[9] Powell Direct Testimony, ll. 315-439.

[10] *Id.* at ll. 440-50.

Table 1.

Annual Functional Costs per Customer			
	Residential Non-Net Metering	Residential Net Metering	Percentage Difference
Generation	$580	$468	-19%
Transmission	$136	$127	-6%
Distribution	$240	$238	-1%
Retail	$40	$57	43%
Miscellaneous	$5	$4	-5%
Total	$1,000	$894	-11%

Third, Mr. Faryniarz demonstrates that NEM compensation for exported power at a retail rate that exceeds net power costs results in the significantly lower parity to cost of service than non-NEM customers, and therefore results in a net cost to other customers.[11] Correcting this cost shift under the NEM regime requires a different rate design for NEM customers that better balances cost of service for consumption from the system with compensation for exported power.

Q. EFCA witness Mr. Gilfenbaum and Vote Solar witnesses Dr. DeRamus and Mr. Gilliam argue that a separate class should not be created because once compensation for exported power is removed, NEM customers are providing approximately the same contribution to cost of service as non-NEM and that it is normal for there to be a small amount of variation within a customer class.[12] Do you agree?

A. No. First, excluding compensation for exported power is irrelevant because NEM equates compensation for exported power with retail rates. Utah Code Ann. § 54-15-

[11] Faryniarz Direct Testimony, ll. 775-855.

[12] Gilfenbaum Direct Testimony, ll. 374-420; DeRamus Direct Testimony, ll. 746-750; Gilliam Direct Testimony, ll. 417-25.

104 requires netting of exported power against consumption within a billing period except for “excess customer-generated electricity,” which is defined in Utah Code Ann. § 54-15-102(6) as the customer-generated electricity in excess of the customers consumption during the monthly billing period. In other words, only the kWh output that exceeds the usage during the billing period (i.e., is banked), may be credited at a different value that is at least avoided cost. Only about 6 percent of exported power is banked; therefore, even if the Commission adjusted the compensation rate for excess energy, as allowed under the law, the vast majority of exported power would be compensated at the retail rate.[13]

Second, for the reasons discussed above, I disagree that the variations in usage characteristics between NEM and non-NEM are insignificant and should be dismissed, particularly when considering the inadequacies of the current rate design to recover costs. Also, looking at just the contribution to the class cost of service (even if compensation for exported power is excluded), or at just load factor, will not show if the rate design is actually sending an economic price signal or whether the design is capable of distinguishing between different service requirements within the class. Net metering customers have distinguished themselves through a variety of factors as I outlined above, some of which result in higher costs and others in lower costs.

Q. OCS witness Ms. Beck states that, while she agrees that NEM customers have a different usage characteristic, a separate class is not needed. How do you respond?

A. Keeping NEM in the same class but requiring different rate designs for NEM customers does not fully capture the differences and actually results in higher rates for NEM

[13] This also provides perspective on UCE's recommendation that if any change is made it be limited to excess generation. Whited Direct Testimony, ll. 599-603.

customers since the benefits of the NEM class are diluted in the larger class. In addition, keeping NEM customers in the current residential class, particularly as the number of NEM customers grows, will increase the intra-class cost shifting and mask the price signal for the value of exported power.

Q. Vote Solar witness Dr. DeRamus argues that the NEM customers, who are typically higher use customers before installing distributed generation, are responding to the rates established by the Commission to discourage high levels of usage so NEM customers should not be singled out. Further, he argues that conflating costs with monthly energy consumption rather than peak load is a problem with the overall rates, not with NEM customers per se.[14] Do you agree?

A. To some extent, I agree with Dr. DeRamus on this point. Indeed, there are problems with the current residential rate structure that cause high use customers to subsidize other customers with the tiered rate design. However, I don't believe that justifies keeping the current rate structure for the NEM program, particularly in light of the required detailed review and evaluation the Commission has sought through this proceeding. NEM customers are not merely akin to customers reducing usage through energy efficiency. High-use customers do not stop being high use consumers, but instead offset a portion of their requirements with private generation, which requires a back-up from the utility. NEM also requires compensation for exported energy at rates in excess of comparable or competitively-priced energy. Together, these differences lead to a significant under-recovery of costs through the NEM program, not just typical lost margins associated with energy efficiency programs. The uniqueness of the NEM

[14] DeRamus Direct Testimony, ll. 402-36.

program, and customers with on-site generation, has already been established and therefore it is appropriate to address changes for these customers.

Q. Dr. DeRamus argues that NEM customers' load factors are not different from those of non-NEM customers.[15] Is this true?

A. No. Mr. DeRamus applied the Kolmogorov-Smirnov ("KS") test to assert that NEM and non-NEM load factors are not significantly different from one another. The KS indeed tests whether two distributions are significantly different from one another. However, it is documented that when testing small sample sizes the power of the KS test is limited.[16] Comparing the annual load factors for NEM and non-NEM customers, as Dr. DeRamus did, provides a sample size of 52 NEM customers, which is not sufficient for the KS test. If Dr. DeRamus's claim that there is no difference in load factors between the groups is true, this should be true when comparing monthly load factors. Therefore, the Company calculated the monthly load factors for NEM and non-NEM customers from the data provided in response to a data request provided to the DPU (DPU DR 4.3). Using the monthly load factors increases the observations from 52 to 621. The Company applied the KS test to the monthly load factors from both groups—NEM and non-NEM. Applying the KS test to the two customer samples results in a p-value of 0.0024, lower than the 0.1 standard, meaning that there are significant differences between the distributions of observations of the two samples. This is consistent with the finding by the DPU using the KS test.[17] Applying the KS

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[15] *Id.* at ll. 935-46.

[16] Razali, Nornadiah M. and Bee Wah Yap, January 2011, *Power Comparisons of Shapiro-Wilk, Kolmogorov-Smirnov, Lilliefors and Anderson-Darling Tests*, Journal of Statistical Modeling and Analytics, Vol 2, No.1, 21-33.

[17] Powell Direct Testimony, ll. 354-6.

test to compare monthly load factors for NEM customers and non-NEM customers demonstrates that the distribution of load factors between the two groups is statistically different.

Q. What analysis did Ms. Whited prepare to support her belief that residential net metering customers should not be on a separate class?

A. Ms. Whited provided her Figure 3 to purportedly show the hourly profiles on the peak day in 2015 (June 30, 2015) for all non-NEM customers whose maximum kW during that peak day was less than 10 kilowatts with the average profiles from the four strata from the residential NEM load research study.[18] She concludes that since the lines for the residential NEM strata are within the same general range as the individual hourly profiles for all other non-residential customers that “NEM customers are well within the range of other residential customers.”[19]

Q. Does Ms. Whited’s Figure 3, along with her observation, provide any evidence that separate class treatment for residential net metering customers would be inappropriate?

A. No. Ms. Whited’s Figure 3 is not an apples to apples comparison of non-NEM and NEM residential customers. There are numerous ways in which the information that she compares for non-NEM customers is on a different basis than for NEM customers. She removes larger non-NEM customers but does not do the same for NEM customers. She shows every single individual sample profile for non-NEM customers, but only shows average strata profiles for NEM customers. For NEM customers, the different strata are shown separately, but non-NEM profiles are just shown in one blue jumble.

[18] Whited Direct Testimony, ll. 291-301.
[19] *Id.* at ll. 297-8.

Besides the inconsistency between the information she shows between NEM and non-NEM customers, the point she tries to make with her illustration is unclear and misleading. She shows that the average NEM strata profiles generally fall within the range provided by *all* non-NEM customers. Her illustration does not demonstrate that the overall profile shape for NEM customers is the same as for non-NEM customers. Using her logic, the profiles for a streetlight or a small irrigation customer could be shown to fall within the range of residential customers. Visually comparing an average from one set of customers to all possible data points from another set of customers is not useful.

Figure 3 in my direct testimony shows that the shapes for the overall profiles, which were prepared on a consistent basis for NEM and non-NEM customers are different on the peak day on June 30, 2015. Her analysis does nothing to refute this difference.

<u>Residential NEM Rate Design</u>

Q. Please summarize parties' positions on the proposed rate design for residential NEM customers, which included a $15 monthly customer charge, a demand charge during on-peak periods, and an energy charge.

A. Parties generally opposed some or all of the Company's proposed rate design. The DPU opposes the proposed customer charge of $15 per month but supports the consideration of both a demand charge and an alternative TOU energy-based option.[20] The OCS supports a different customer charge and a requirement for TOU rates in the next general rate case.[21] Sierra Club, UCE, Vivint Solar, and Vote Solar oppose the

[20] Faryniarz Direct Testimony, ll. 1345-7.
[21] Beck Direct Testimony, ll. 600-4.

Company's proposed rate design, and in particular, argue that the demand charge is inappropriate for residential customers but offer some support for a TOU energy-based rate (but available to all residential customers).[22]

Q. Is the Company proposing changes to the proposed rate design in this rebuttal filing?

A. Yes. In Section II of my testimony, I explain the Company's changes to the proposed rate design. The Company is proposing to include an optional TOU energy option in addition to the TOU demand-based option for residential NEM customers.

Q. Regarding the proposed customer charge, DPU witness Mr. Faryniarz argues that the cost of service for NEM customers does not support a higher customer charge that includes the costs of transformers, as proposed by the Company.[23] Similarly, OCS witness Mr. Martinez also opposes the inclusion of transformer costs in the customer charge.[24] Do you agree with their arguments?

A. No. Both Mr. Faryniarz and Mr. Martinez rely on the Commission's 1985 method for determining customer charges, which limits the customer charge to only costs that serve individual customers, not costs for equipment that is shared by customers.[25] However, as DPU witness Dr. Powell notes: "rate-making must be sufficiently flexible to adapt to changing circumstances."[26] A strict adherence to a Commission determination 32 years ago does not serve the public interest. The changes in technology, growth in

[22] *See e.g.*, Clements Direct Testimony, ll. 436-43. Whited Direct Testimony, ll. 48-50, 541-5, 564-8. Plagemann Direct Testimony, ll. 48-167. DeRamus Direct Testimony, ll. 102-18, 128-32. Gilliam Direct Testimony, ll. 79-85, 121-31.
[23] Faryniarz Direct Testimony, ll. 123-7.
[24] Martinez Direct Testimony, ll. 195-210.
[25] Martinez Direct Testimony, ll. 62-226; Faryniarz Direct Testimony, ll. 680-733.
[26] Powell Direct Testimony, ll. 201-2.

customer generation, and in particular, the present circumstance of net metering—which over-simplistically equates the retail rate with a value for exported energy, resulting in a cost shift to other customers—warrant a re-evaluation of the past approach for a proper balance between price signals and cost recovery.[27]

As Table 1 above shows, functional cost of service differences between NEM and non-NEM exist, with NEM customers exhibiting lower costs for generation and transmission and higher costs for distribution and retail functions. The distribution costs include substations, poles, wires, transformers, service drops, and meters. Table 2 provides a breakdown of the distribution costs and comparison to non-NEM customers.

Table 2.

Residential Customer Costs			
	Residential Non-Net Metering	Residential Net Metering	Percentage Difference
Transformer	$50.66	$63.87	26%
Meter	$7.83	$14.67	87%
Service	$32.25	$38.09	18%
Retail	$39.64	$56.64	43%
Miscellaneous	$4.54	$4.32	-5%
Annual Total	$134.93	$177.59	32%
Monthly Total	$11.24	$14.80	32%

Table 2 shows that the most significant cost differences are in meters, transformers, and retail, which excludes the costs to be recovered in the Company's proposed application fee. The Company proposes to include the transformer costs in the customer charge for

[27] The Commission has recognized that changes to methodologies are warranted in light of changing conditions (*see e.g.*, Docket No. 12-035-100, Order on Phase II Issues (August 16, 2013) p. 18, where the Commission justified changing the avoided costs methodology stating "... [t]his action will ensure our method for determining indicative prices will continue to reflect changing avoided costs in light of changing conditions ...")

NEM customers with the demand-based TOU rate proposal. As I discuss later, the Company is proposing a higher customer charge that includes all distribution system elements with its new proposed TOU energy option.

Q. Please explain why NEM is a reasonable basis for the Commission to alter its past decisions for the calculation customer charges.

A. The cost of service study shows that NEM results in a significant under-recovery of costs, which is largely due to using the retail rate to value exported energy. With the costs of infrastructure necessary to support customers' access to the grid included in volumetric rates, customers can offset charges for infrastructure they relied on for their own consumption through the NEM kWh netting and banking process. The majority of costs in rates reflect the embedded costs of the facilities in place and serving customers today, therefore, these are costs that do not go away, regardless of consumption levels. In fact, as Company witness Mr. Douglas L. Marx shows, rooftop solar does not necessarily lead to a reduction in the size of local distribution infrastructure because these customers use the distribution system for both consumption and export. Therefore, to ensure cost recovery from the individuals who rely on and benefit from this infrastructure, the costs must be removed from the volumetric charges.

Q. The OCS recognizes a difference in meter costs between residential NEM and non-NEM customers and proposes a customer charge of $8.50.[28] Please respond.

A. The current minimum bill for residential customers is $8.00 per month. So while I appreciate the OCS's recognition of cost differences for NEM customers, the proposal still leaves a significant portion of fixed costs subject to volumetric rates and

[28] Martinez Direct Testimony, ll. 220-6.

netting/banking.

Q. Vivint Solar argues that transformers should not be in the customer charge for NEM customers because Mr. Marx's arguments that NEM customers put a greater burden on the grid are "a red herring and only applied in limited cases."[29] Does the Company's proposed customer charge reflect any additional costs for prospectively putting a greater burden on the grid, as Mr. Marx showed?

A. No. While Mr. Marx shows that NEM can actually lead to the need for additional costs to support the excess energy placed on the grid, the Company's proposed customer charge does not reflect any additional costs beyond those in the test period (scaled back to the final rates approved in the last general rate case). Therefore, Mr. Collins argument is misleading.

Q. Vivint Solar argues that "a reasonable and small minimum bill" would be a better solution than a higher customer charge because it promotes conservation.[30] Do you agree?

A. No. A minimum bill is often proposed as a solution in NEM proceedings, but is essentially a red herring because it makes it appear that the utility would get better fixed cost recovery. In reality however, unless the charge is set high enough, it produces insufficient revenue. For example, the Company's current minimum bill is $8.00 per month. A 50 percent increase in the minimum to $12.00 per month for NEM customers would apply to only 3 percent more bills, based on the 2015 test period. In addition, it only "promotes conservation" in that it leaves recovery of fixed costs in the volumetric rate, regardless if that is actually an economic price signal.

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[29] Collins Direct Testimony, ll. 725-50.

[30] Plagemann Direct Testimony, ll. 84-93.

Q. Do you agree with parties' arguments that demand charges for residential customers are inappropriate?[31]

A. No. As several parties note, there is a growing interest by utilities across the country in incorporating demand changes into residential rate design due to changes in technology.[32] But arguments like the Sierra Club's that residential customers are "not in a position to respond to demand price signals" or that demand charges are simply too inconvenient are unfounded.[33] The Arizona Public Service Company has had voluntary TOU demand and energy options for residential customers for decades. A study published in 2016 looked at customers that switched from a TOU energy rate to a TOU demand-based rate and found that about 60 percent of customers were able to reduce their summer peak demand an average of 12.5 percent.[34] Responding to a demand signal would be a change for residential customers, but it does not mean demand charges are not appropriate or useful in this context. In fact, demand charges are a more appropriate, economic price signal than tiered energy rates, for the reasons I discussed in my direct testimony. Gaining an understanding to stagger appliance use during peak periods provides a more cost-causation-based price signal than just reducing overall usage.

Sierra Club claims that residential customers "have almost no perceptible impact on the grid based on their own individual usage" so therefore, "the grid would

[31] Clements Direct Testimony, ll. 309-57; Whited Direct Testimony, ll. 363-512; Plagemann Direct Testimony, ll.102-4.

[32] Clements Direct Testimony, ll. 339-46. Whited Direct Testimony, ll. 484-512. Plagemann Direct Testimony, ll. 32-6, 100-2.

[33] Clements Direct Testimony, ll. 329-57.

[34] Leland R. Snook and Meghan H. Grabel, *Dispelling the myths of residential rate reform: Why an evolving grid requires a modern approach to electricity pricing*, THE ENERGY LAW J. 29:3 (Apr. 2016) at 72-76.

barely notice unless hundreds or thousands of other customers did the same thing at the same time,"[35] and compares this to an industrial customer. This ignores the fact the all non-residential classes, other than lighting, are subject to demand charges, not just large industrial customers and that applying the on-peak demand price signal to hundreds or thousands of customers is precisely how to discourage more costly on-peak usage. An individual customer reducing usage to the peak period demand price signal is of more value to the grid than if the same customer merely reduces his or her usage by the corresponding amount in non-peak periods during a billing month in response to tiered energy rates.

I similarly disagree with UCE witness Ms. Whited's arguments that demand charges reduce incentives for energy efficiency, that a reduction in energy charges will lead to an increase in usage, and that the demand charges violate the Bonbright principle of simplicity.[36] While demand charges are a different signal for residential customers, they are still a price signal for efficiency—a more targeted and valuable signal for efficiency than tiered rates. The Company's proposed rate design is also more simplistic than the current tiered rates and customers do not necessarily respond to individual billing components, but to average prices or overall bills.[37]

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[35] Clements Direct Testimony, ll. 322-26.
[36] Whited Direct Testimony, ll. 457-66.
[37] Koichiro Ito, *Do Consumers Respond to Marginal or Average Price? Evidence from Nonlinear Electricity Pricing*, Energy Institute at Haas (October 2012).

Q. Several witnesses argue that if there were a new rate design adopted for customer generators, a residential TOU energy-based rate rather than a demand-based rate would be more appropriate.[38] How do you respond?

A. In this rebuttal filing, the Company is proposing to offer an optional energy-based TOU rate in addition to the demand-based TOU rate initially proposed. The proposed rates are described in Section II of my testimony. These two options will help customers adjust to new time-based price signals and ultimately choose the rate that most advantageously reflects his or her desired consumption.

Q. Several parties argue that the proposed new rates will result in an unacceptable bill increase for NEM customers.[39] Do you agree?

A. No. The increase is only in comparison to what would otherwise occur. Put otherwise, just because a bill increases to an amount that is actually reflective of the costs imposed by a customer does not mean that the increase is unacceptable. In this context, as the Company's cost of service analysis shows, NEM customers have been receiving a windfall under the current program and have been paying substantially less than their cost of service. In addition, it's not an actual increase to customers because the Company proposes to apply Schedule 5 rate to only *new* NEM customers (submitting applications after December 9, 2016). When a customer opts for NEM after this proceeding, the overall average bill result would still be a decrease, as shown on pages 2 and 3 in Exhibit RMP___(JRS-1R).

[38] Beck Direct Testimony, ll. 600-4; Daniel Direct Testimony, ll. 292-9; Whited Direct Testimony, ll. 564-8.
[39] Whited Direct Testimony, ll. 160-70. Clements Direct Testimony, ll. 358-414. Plagemann Direct Testimony, ll. 145-67.

Large Non-Residential Excess Energy Credits

Q. Please summarize other parties' testimony in response to the Company's proposal to eliminate the option for the average retail rate credit for excess energy for large non-residential customers.

A. Only the DPU and the OCS briefly addressed the Company's proposal in testimony. Mr. Faryniarz for the DPU doesn't make a specific recommendation but notes the importance of correctly valuing exports for all NEM customers, including non-residential.[40] For the OCS, Ms. Beck notes that it would be important to evaluate whether all NEM customers should receive the same compensation rate and whether additional changes are necessary in a post-NEM environment.[41]

Q. Based on testimony, are you altering your proposal to eliminate the average retail rate option for large non-residential customers?

A. No. As both the DPU and OCS note, there should be consideration of consistency in the value of exported energy across the classes, and the current large non-residential option for compensation of excess energy at the average retail rate is in excess of the benefits, and therefore should be eliminated. For example, Table 3 below compares the benefit of the net metering program at the system, state, and customer class level for Schedules 6, 8, and 10 from the updated analysis presented in Company witness Mr. Meredith's rebuttal testimony. This shows that the benefits provided by large non-residential net metering customers are all less than the average retail price option those customers can receive for their excess energy.

[40] Faryniarz Direct Testimony, ll. 1197-1204.
[41] Beck Direct Testimony, ll. 466-73.

Table 3

Benefit of the Net Metering Program ($/MWh)				
		At the Customer Class Level		
At the System Level	At the State Level	Schedule 6	Schedule 8	Schedule 10
27.18	57.21	54.12	69.88	45.80

Average Retail Rate on Schedule 135 Special Condition 2.B.(iii) Effective July 1, 2016 ($/MWh)				
Schedule 6	Schedule 6A	Schedule 6B	Schedule 8	Schedule 10
84.50	117.87	108.91	75.51	75.62

Q. If the average retail rates are more than the benefit of the net metering program, why isn't there a larger net cost for large non-residential customer classes?

A. Schedule 6, Schedule 8, and Schedule 10 customers primarily receive value for their private generation through their onsite generation or the generation that is netted within the month at energy charges instead of at the full average retail rate. The full average retail rate is only available for excess credits that are banked from a prior month. Table 4 below shows the average cost of bill credits for the large non-residential customer classes.

Table 4

Net Metering Cost of Bill Credits ($/MWh)		
Schedule 6	Schedule 8	Schedule 10
46.82	38.55	46.52

Since large non-residential customers are subject to demand charges, the average cost of bill credits for these customer classes is well below the average retail rates shown in Table 3. The costs and benefits of the NEM program analysis shows a smaller net cost for large non-residential classes as compared to the residential class because of lower bill credit levels for large non-residential classes. This is a direct result of the more cost-based rate structures for large non-residential customers. The

Company recommends that the current rate structure for customers on Schedule 6, 6A, 6B, 8, and 10 who choose to participate in the NEM program remain in place, since those structures do not cause these customers to pay amounts that are far off from what cost of service analysis indicates they should pay. Compensating these customers for a prior month's over-generation at a higher rate, however, has no basis in cost and should be eliminated as an option for future large non-residential NEM customers.

<u>Application Fees</u>

Q. Did any party oppose the Company's proposed waiver of R746-312-13 and the implementation of new application fees for Level 1 interconnection requests and changes to the fees for Levels 2 and 3?

A. No party opposed the waiver and implementation of the $60 application fee for Level 1 interconnection requests. The OCS, however, recommended that the proposed increases in the Level 2 and 3 fees should stay the same until the next general rate case. The OCS also recommends that the Commission consider a formal rulemaking to review R746-312-13 on a longer-term basis.[42]

Q. Do you agree with the recommendations by the OCS?

A. In part. The Company can agree to withdraw the proposed increases for Level 2 and 3 interconnection applications at this time. The Company also supports the OCS's recommendation for the Commission to consider a formal rulemaking to review R746-312-13 on a longer-term basis. In fact, an update to the rule section may be appropriate to address the availability of battery storage at customer locations, in addition to interconnection of generation facilities. However, the Company believes that the

[42] Martinez Direct Testimony, ll. 295-321.

rulemaking may consider changes in costs for Level 2 and 3, not just limit a change in fees to a general rate case as these are set in rules.

Proposed Deferral for Incremental Revenue from Schedule 5

Q. Did any party comment on the Company's proposed deferral for incremental revenue from Schedule 5?

A. Only one. The OCS opposes the Company's proposal to establish deferred accounting for any incremental amount associated with new rates until the next general rate case. The OCS witness Mr. Daniel argues that the proposal does not include enough information or specifics on the deferral account for the Commission to make a decision. The OCS's questions include: how will the increased revenues be calculated; when, and over what period would the increased revenues be returned to customers; how will the increased revenues be assigned or allocated to customer classes; and will there be a true-up provision and, if so, how will it work?[43]

Q. How would the Company calculate the revenue difference?

A. Each month, the billing components would be extracted for Schedule 5 customers from the billing system. From those billing components, actual base revenue under Schedule 5 and what base revenue would have been under Schedule 1 would be calculated and compared. The incremental difference between Schedule 5 revenue and Schedule 1 revenue for all bills during the month would be applied to the balancing account, plus any carrying charge on the balance. The Company would use the carrying charge rate approved by the Commission in Docket No. 15-035-69. Exhibit RMP___(JRS-2R) provides an example of the calculation.

[43] Daniel Direct Testimony, ll. 317-68.

The Company would begin the deferral once customers begin taking service on Schedule 5, following the first monthly billing. The deferral would continue with all customer billings until the effective date of the Company's next general rate case.

Q. When and over what period does the Company propose to return the deferral to customers?

A. The Company proposes to begin amortizing the deferral at the time of the next general rate case. The Company would make a specific proposal in the general rate case filing, including, the proposed period over which to amortize the balance. Other parties would be able to propose an alternative at that time as well.

Q. How does the Company propose to allocate the deferral balance to customer classes?

A. The deferral revenue balance would be allocated back to the residential Schedule 1 class.

Q. Does the Company propose a true-up provision?

A. The Company would make a specific proposal in the next general rate case filing. If amortization is embedded in base rates, there would not be a true-up. If the amortization is done through a separate adjustment, a true-up provision would likely be included. The size of a deferral balance is a factor that the Company would consider at the time of the next general rate case as it makes its proposal for amortization.

II. Revised Schedule 5 Rate Design

Q. Is the Company proposing any changes to the originally proposed Schedule 5 rates?

A. Yes. The Company has two changes to the Schedule 5 rates I proposed in direct testimony. First, the Company updated the Schedule 5 TOU demand-based rates in the initial filing based upon the updated NEM Breakout COS analysis presented by Company witness Mr. Meredith in his rebuttal testimony. The rates are calculated using the same logic as discussed in my direct testimony, but they also reflect a correction to the billing units for the on-peak demand charge.[44] Table 5 below shows the updated prices compared to the proposed prices presented in direct testimony. The updates and the correction to the demand charge billing units result in reductions to the customer, demand, and energy charges as compared to Company's direct filing.

Table 5 – Proposed Prices Compared to Prices Proposed in Direct Filing

Schedule 5 - Residential Service for Customer Generators		
	Proposed Price	
	Direct Filing	Revised Rebuttal Filing
Customer Charge		
1 Phase	$15.00	$13.00
3 Phase	$30.00	$26.00
Demand Charge		
On-peak ($/kW)*	$9.02	$8.25
Energy Charges		
All kWh (¢/kWh)*	3.8143	3.6374
*On-peak periods: Monday-Friday (except holidays) 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.		

Q. What is the second proposed change to Schedule 5?

A. In response to the testimonies of other parties, the Company proposes to include an optional TOU energy-based rate in addition to the TOU demand-based rate. Providing both a demand-focused TOU option and an energy-focused TOU option gives

[44] *See* Joelle R. Steward Direct Testimony, ll. 289-304 and 399-422.

customers more flexibility to choose an option that works for their household.

Q. How were the rates designed for the energy focused TOU option?

A. The off-peak energy charge was set to the same 3.6374 cents per kilowatt hour energy charge as in the demand focused TOU option, and the customer charge was set at $28 per month instead of $13 per month. The on-peak energy charge was then set to recover the remaining revenue requirement. The on- and off-peak TOU periods are identical between both options. Table 6 shows the proposed prices for both of the Company's proposed options.

Table 6

Schedule 5 - Residential Service for Customer Generators		
	Proposed Price	
	Option 1 - Demand Focused Time-of-Use	Option 2 - Energy Focused Time-of-Use
Customer Charge		
1 Phase	$13.00	$28.00
3 Phase	$26.00	$56.00
Demand Charge		
On-peak ($/kW)*	$8.25	N/A
Energy Charges		
On-peak kWh (¢/kWh)*	3.6374	28.5533
Off-peak kWh (¢/kWh)*	3.6374	3.6374

*On-peak periods: Monday-Friday (except holidays)
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.

Q. Why is the Company proposing a higher customer charge for the energy focused TOU option?

A. Without a higher customer charge, an energy focused TOU rate that still includes netting and banking does not provide a sufficient level of fixed cost recovery. Customers on such a rate can offset all of their bill except for the customer charge by simply installing enough rooftop solar panels. The proposed $28 customer charge for the energy-focused TOU option is designed to recover all customer services and distribution costs.

Q. What evidence shows that an energy focused TOU rate without a higher customer charge provides an insufficient level of fixed cost recovery?

A. To understand how well different rate options track the recovery of costs incurred to serve a customer, the Company prepared an analysis that examines how the cost of service would change for a customer who installs different sized rooftop solar systems relative to the bill savings that customer would achieve from different rate options. Specifically, the Company examined a typical NEM customer with 1,000 kWh of monthly energy consumption against different levels of generation that would offset 10 percent, 25 percent, 50 percent, 75 percent, and 100 percent of full requirements usage. To estimate cost of service at these levels of solar adoption, the change in the customer’s overall share of cost-causing customer characteristics was measured after applying the estimated solar profile at different magnitudes. See Figure 1 below for a comparison of bill savings and change in cost of service at different levels of rooftop solar penetration for both the Company’s proposed demand focused TOU option and an energy focused TOU option that has the same $13 customer charge, as well as the current Schedule 1 rates.

Figure 1. Cost of Service Compared to Bill Savings on Demand Focused TOU and Energy Focused TOU

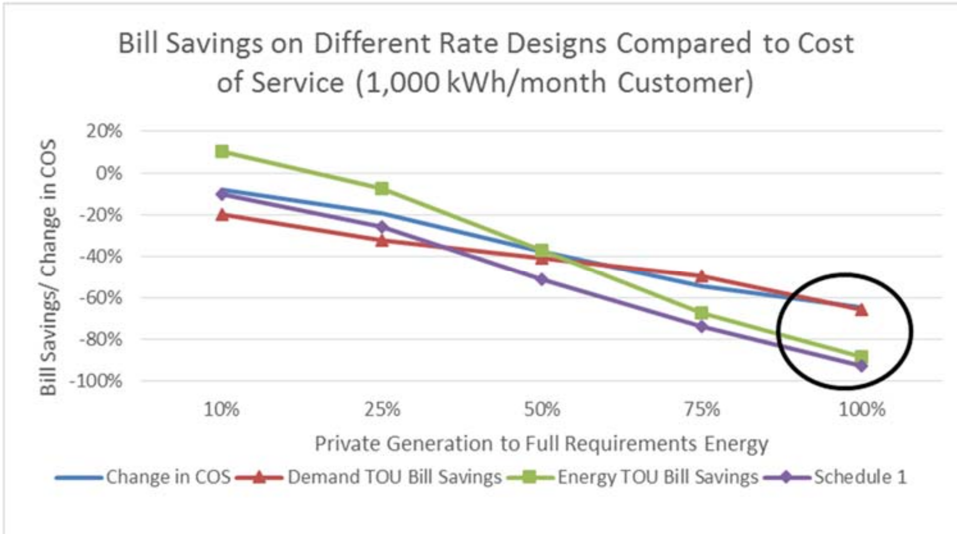
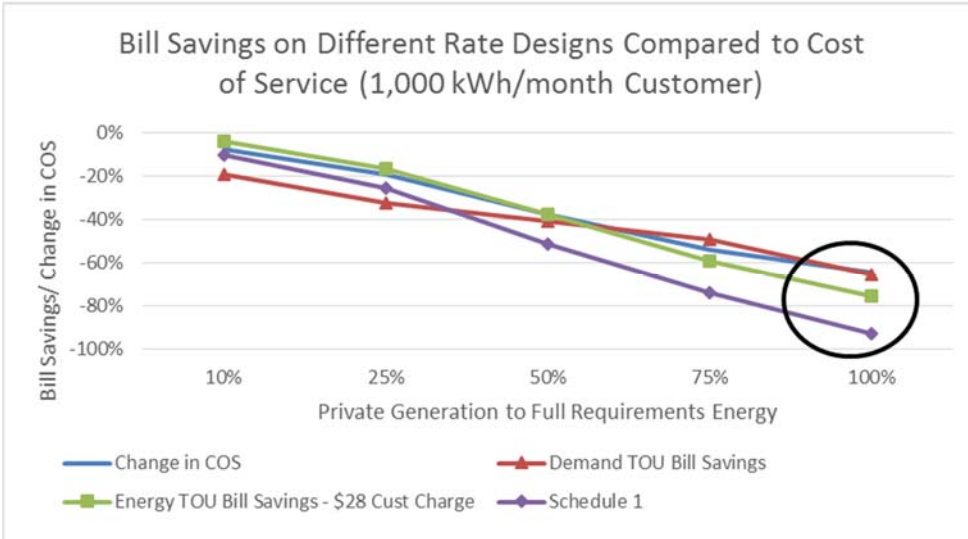


Figure 1 shows that the demand-based TOU option tracks more closely to cost of service than an energy-based option or the Schedule 1 rates, particularly when a customer installs larger private generation systems.

To achieve better fixed cost recovery, the Company recommends that a $28 customer charge be used for an energy focused TOU option. Figure 2 below shows how an energy focused TOU with a higher $28 customer charge better tracks cost of service.

Figure 2. Cost of Service Compared to Bill Savings on Demand Focused TOU and Energy Focused TOU with a $28 Customer Charge



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

A. Yes. Exhibit RMP___(JRS-1R) shows the proposed rate and a monthly bill comparison at different usage for the proposed Schedule 5 rates in the same format as in Exhibit RMP___(JRS-7), which was provided with my direct testimony. Page 2 of Exhibit RMP___(JRS-1R) shows the potential bill impacts for the Company's proposed demand-based TOU option. Page 3 shows the potential bill impacts for the Company's proposed energy-based TOU option.

Q. How does the Company propose to implement these rate options?

A. The Company will add a provision to the application for interconnection for the customer to elect which rate option they would like to choose. If the customer does not indicate a selection at that time, the default will be to place the customer on the demand-based option. The customer will be allowed to change his or her selection at any point during the first year. After the first year, a customer may change rate options once in a 12-month period. The Company will work with stakeholders to develop educational materials to be available to customers to assist their understanding of the new rates.

Q. Several parties argue that the Commission should not or cannot approve new rates outside of a general rate case.[45] Do you agree?

A. No. This argument runs counter to the Commission's decision on the intervenors' motions for summary judgment and motions to dismiss, in which the intervenors made the same assertion. In its February 23, 2017, Consolidated Order Denying Dispositive Motions, the Commission specifically ruled that the Legislature did not intend for the Commission "to refrain from fulfilling its obligations under the Statute until and unless a general rate case is initiated."[46] Rather, the Commission explained:

> As they are now, the issues of the cost to serve net metering customers and the appropriate pricing for their services were matters of substantial controversy. In our view, the Statute constitutes the instructions and authority the legislature elected to give the PSC for the purpose of addressing these issues. As numerous parties have pointed out, as long as these issues remain unresolved, the rooftop solar market is operating under uncertainty and consumers are without accurate price signaling in deciding whether to invest in rooftop solar. These issues are better resolved sooner rather than later. If the legislature had intended for us to act only in the context of the then pending or a later filed general rate case, it could have made its intentions plain. Instead, we believe the legislature was responding to the specific circumstances and controversy surrounding net metering and empowered the PSC to act to resolve it.[47]

Given this, intervenor arguments to the contrary are further attempts to re-litigate issues and are irrelevant to this proceeding. The Company agrees with the

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[45] Whited Direct Testimony, ll. 599-603; Daniel Direct Testimony, ll. 377-85.
[46] Docket No. 14-035-114, Consolidated Order Denying Dispositive Motions, at 7 (Utah P.S.C. February 23, 2017).
[47] *Id.* at ll. 8.

Commission that the rooftop solar market is in need of certainty and stability and that the Commission should not wait for a general rate case to make a decision on the NEM rate structure.

III. Net Metering Successor Program

Q. Please summarize the proposals by the DPU and OCS for a successor program to NEM for customer generators.

A. Both the DPU and the OCS recommend that the Commission lower the cap on the NEM program and initiate the development of a new program for customer generators with a separate compensation rate for exported energy. They propose that the Commission initiate a new proceeding to develop a methodology or formula for calculating the compensation rate.[48]

The DPU recommends that the Commission immediately lower the program cap on the NEM program to reflect the approximate size the program will be on January 1, 2018, and close that program to new customers, and request that the legislature eliminate the NEM program altogether January 1, 2025. DPU proposes a transition plan for new customers with distributed generation after the NEM program closes until January 1, 2025, after which all residential distributed generation customers would be subject to whatever new rate structure(s) the Commission determines for consumption in this proceeding or a general rate case and separate compensation rates for exported power. During the transition period and until the proceeding has been completed to establish the compensation methodology and export rate, DPU recommends a compensation rate for exported power that is the mid-point between the average retail

[48] Powell Direct Testimony, ll. 454-582; Beck Direct Testimony, ll. 337-653.

rate for energy and the avoided cost rate. The DPU also recommends that the Commission adopt at least two rate structures for the post-NEM program, one with rates similar to the Company's proposed three-part rates and one TOU with on- and off-peak energy prices.

The OCS recommends that the Commission lower the NEM program cap to approximately 10 percent. The OCS also proposes a transition plan pending a future proceeding, but advocates extending the transition period for 12 years, until January 1, 2030. The compensation rate would start at 9 cents/kWh for new post-NEM distributed generation customers, and decrease every year or two, transitioning into the new rate that would be determined in the new proceeding to establish a compensation method and rate. For rate design, the OCS recommends the Commission approve TOU rates for residential and small commercial customers, to be calculated and implemented in the next general rate case. OCS also recommends that a new facilities charge be calculated in the next general rate case to apply to NEM program customers beginning January 1, 2030.

Q. Do you agree with their recommendations to lower the cap on the NEM program?

A. Yes. The Company agrees that the most appropriate path forward is to lower the NEM program cap and put in place a new program that separately considers the costs for consumption from the grid and a rate for exported power. In light of the costs of the NEM program, the Company recommends that the Commission initiate the transition to a new program paradigm and adopt the DPU's recommendation to lower the NEM program cap as of the estimated program size on January 1, 2018.

Q. Please elaborate on why the Company supports the DPU's recommendation to lower the cap to the program size expected January 1, 2018.

A. The Company estimates that, by the end of 2017, the NEM program will have interconnected or have pending applications for installations that equate to nearly 5 percent of NEM program cap, which is 231 MW. At 231 MW, assuming residential comprises 75 percent of installed capacity, the annual residential cost shift would be $12.5 million. At a 10 percent threshold, as proposed by the OCS, the annual cost shift would double to $25.0 million. The Company estimates that the program will reach the 10 percent threshold, or 462 MW, during 2020 or early 2021. Waiting to take action would not be in the public interest and would continue the incorrect market signals, over-value the power exported to the grid, and perpetuate the customer confusion that currently exists. In addition to the DPU and OCS explicitly recognizing that the current NEM program regime results in cost shifting, other parties—notably EFCA, UCE, Vivint Solar, and Vote Solar—implicitly acknowledge that equating the export credit to the retail rate is problematic and recommend that, if modification to the current program is necessary, changes should be made to the export compensation.[49] Transitioning away from the current NEM program sooner would help provide a more certain pathway for both customers and solar developers, while minimizing negative impacts on other customers.

[49] *See e.g.*, EFCA argues that adjusting the export rate may resolve the Company's concerns requiring a separate class. Gilfenbaum Direct Testimony, ll. 414-20. UCE recommends that, if a change in the NEM program is necessary, compensation for excess generation should be reduced. Whited Direct Testimony, ll. 559-63. Vivint proposes an alternative that would step down the value for exported energy. Plagemann Direct Testimony, ll. 281-3. Vote Solar proposes a declining compensation rate for net excess energy to address the Company's concerns about cost shifting. Gilliam Direct Testimony, ll. 760-3.

Q. Does the Company support establishing a new program with a separate compensation rate for exported power and a new proceeding to set the methodology for that compensation rate?

A. Yes. The Company supports the framework adopted by the Commission in Phase 1 of this proceeding that uses the cost of service study to evaluate the NEM program because NEM equates the value of customer generation to the retail rate. In other words, the Company believes that, so long as retail rates are applied to NEM, the same model used in setting retail rates is appropriate to assess the costs and benefits of NEM and formulate an appropriate rate structure. However, if the export rate is separated out from consumption, i.e., netting and banking are eliminated, the Company would support a renewed look at how to set the rate to compensate exported power from customer generators.

Q. If the Commission opened a new proceeding, what should the proceeding consider?

A. The proceeding should consider how or if the value of exported power is different than the value already determined by the Commission for calculating avoided costs for small power producers under Schedule 37. The Commission has already determined that the customer generation equipment is not a system resource as the Company has little if any control over the systems and the customer is under no obligation to maintain the system or supply the utility with electricity.[50] Moreover, customer generation exported to the grid is incidental to the purpose of the installation, which is to support or self-supply the customer's own needs. Nevertheless, exported power is essentially a must-

[50] Docket No. 14-035-114, Order, at Section 2.7 (Utah P.S.C November 10, 2015).

take obligation by the Company. Thus, the proceeding should consider the value of exported power against this backdrop and the Commission's previous determinations for the avoided cost rates for other power the Company is obligated to purchase. It should also consider the frequency of updates to the compensation rate to stay current with changes in the market or other changes in quantifiable costs and benefits.

Q. Do you agree with the DPU's proposal to establish a transitional compensation rate that is the mid-point between the average retail rate and avoided costs?

A. No. This proposed transitional rate would be approximately 6.7 cents/kWh. This is far in excess of the rates the Commission has already determined for the Company's purchases of electricity from third-party suppliers through avoided costs or through the competitive wholesale market. The Commission is required to set just and reasonable rates. Without evidence or data that there is additional value of this must-take generation, the Commission should not arbitrarily set a new rate for energy or merely split the difference. Accordingly, the Company proposes that the Commission use approved Schedule 37 rates for a fixed solar facility, adjusted for losses at the primary or secondary voltage levels, until a new proceeding is completed.

Q. How would the export compensation be treated on the customer's bill and through ratemaking?

A. The Company's current meters separately register the electricity a customer takes from the grid and the electricity the customer's generation exports to the grid. The Company would multiply the measured exported power by the compensation rate set by the Commission to calculate a monthly bill credit for the customer. The credit would be applied against the customer's monthly energy and power charges on the bill. The bill credit would not be applied against any monthly fixed charges or minimum bills in order to ensure recovery of non-by passable costs. In order to provide an economic signal for the customer to properly size his or her facility (i.e., a system sized to serve on-site needs), any dollar credits would carry over to the next monthly bill during an annual program period, such as the end of March. At the end of the 12-month program period, any excess bill credits would expire with the remaining balance donated to the low income program, similar to the current treatment under the NEM program. Customer generation that is used to serve the customer's on-site usage (i.e., stays behind the meter) would result in a reduction in usage from the utility and would effectively receive the value of retail rates.

As noted by Dr. Powell, recovery of the exported power compensation would flow through the Energy Balancing Account, or other mechanism, as a purchased power expense on a situs Utah basis.[51]

Q. What is the Company's recommendation for rates for consumption under the new program?

A. Even under a new program that eliminates netting and banking of exported power, a new customer rate structure would be appropriate in order to capture the change in the customer profile. Rate structures such as those proposed for Schedule 5 in this rebuttal filing—a demand-based TOU and an energy-based TOU rate design—would be appropriate for the reasons already addressed above.

[51] Powell Direct Testimony, ll. 546-8.

Q. Please summarize why the Commission should move to adopting a new program for customer generation that does not rely on kWh netting and banking of exported power.

A. One of the most significant causes of cost shifting due to the NEM program is that it conflates the retail rate with a value for exported energy. The retail rate, however, recovers significantly more costs that are necessary for the provision of safe and reliable energy from the utility than just the value of purchased energy. In order to create more sustainable, economic price signals, the Company, along with the DPU and OCS, proposes establishing a new program for private generation customers that eliminates netting and banking and provides a compensation rate for exported energy from private generation systems. The compensation rate should consider the value of this must-take energy to the utility based on treatment consistent with how other power purchases are valued. Separating the compensation rate for exported power from the retail rate will also allow it to change as the market or other quantifiable values change.

Q. Does this conclude your rebuttal testimony?

A. Yes.

Rocky Mountain Power
Exhibit RMP___(JRS-1R)
Docket No. 14-035-114
Witness: Joelle R. Steward

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

Exhibit Accompanying Rebuttal Testimony of Joelle R. Steward

Revised Proposed Schedule 5 Rates and Monthly Billing Comparisons

July 2017

Schedule 5 - Residential Service for Customer Generators		
	Proposed Price	
	Option 1 - Demand Focused Time-of-Use	**Option 2 - Energy Focused Time-of-Use**
Customer Charge		
1 Phase	$13.00	$28.00
3 Phase	$26.00	$56.00
Demand Charge		
On-peak ($/kW)*	$8.25	N/A
Energy Charges		
On-peak kWh (¢/kWh)*	3.6374	28.5533
Off-peak kWh (¢/kWh)*	3.6374	3.6374

*On-peak periods: Monday-Friday (except holidays)
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.

Rocky Mountain Power
Monthly Billing Comparison
Schedule 136 - State of Utah
Bill Savings from Proposed Demand Focused TOU Schedule 5 Rates for New Residential NEM Customers

% of DG Production to Full Requirements Energy Usage

Full Requirements	0%	0%		10%		25%		50%		75%		100%	
Monthly kWh	Present	Proposed	% Change	Proposed	% Change	Proposed	% Change	Proposed	% Change	Proposed	% Change	Proposed	% Change
500	$55	$50	-10%	$48	-13%	$45	-19%	$40	-27%	$35	-36%	$31	-45%
750	$85	$77	-9%	$65	-23%	$61	-28%	$54	-36%	$47	-45%	$31	-64%
1,000	$114	$95	-16%	$92	-20%	$77	-32%	$67	-41%	$58	-49%	$39	-65%
1,250	$146	$114	-22%	$109	-26%	$102	-30%	$81	-45%	$69	-53%	$48	-67%
1,500	$179	$132	-26%	$126	-29%	$118	-34%	$94	-47%	$80	-55%	$57	-68%
1,750	$211	$151	-29%	$144	-32%	$134	-37%	$108	-49%	$82	-61%	$65	-69%
2,000	$244	$178	-27%	$161	-34%	$150	-39%	$122	-50%	$93	-62%	$74	-70%
2,500	$309	$214	-30%	$205	-34%	$182	-41%	$149	-52%	$116	-62%	$83	-73%
3,000	$373	$251	-33%	$240	-36%	$213	-43%	$176	-53%	$138	-63%	$100	-73%

Assumptions

1. Average monthly DG generation kWh/kW	116
2. Average on-peak load factor %	29%
3. Average monthly Full kWh for Residential NM customer	977
4. DG demand impact index: on-peak kW/MWh	1.47
5. Estimated on-peak kW = Full kWh/(730*29%) - DG MWh x 1.47	

Rocky Mountain Power
Monthly Billing Comparison
Schedule 136 - State of Utah
Bill Savings from Proposed Energy Focused TOU Schedule 5 Rates for New Residential NEM Customers

% of DG Production to Full Requirements Energy Usage

Full Requirements	0%	0%		10%		25%		50%		75%		100%	
Monthly kWh	Present	Proposed	% Change	Proposed	% Change	Proposed	% Change	Proposed	% Change	Proposed	% Change	Proposed	% Change
500	$55	$74	33%	$69	24%	$62	11%	$49	-11%	$37	-32%	$28	-49%
750	$85	$96	14%	$89	5%	$78	-8%	$60	-29%	$42	-50%	$28	-67%
1,000	$114	$119	5%	$109	-4%	$95	-17%	$71	-38%	$47	-59%	$28	-75%
1,250	$146	$142	-3%	$130	-11%	$112	-24%	$81	-44%	$51	-65%	$28	-81%
1,500	$179	$165	-8%	$150	-16%	$128	-28%	$92	-49%	$56	-69%	$28	-84%
1,750	$211	$187	-11%	$170	-19%	$145	-31%	$103	-51%	$60	-71%	$28	-87%
2,000	$244	$210	-14%	$191	-22%	$162	-34%	$113	-53%	$65	-73%	$28	-88%
2,500	$309	$256	-17%	$231	-25%	$195	-37%	$135	-56%	$74	-76%	$28	-91%
3,000	$373	$301	-19%	$272	-27%	$228	-39%	$156	-58%	$83	-78%	$28	-92%

Assumptions

1. Average monthly DG generation kWh/kW	116
2. Average on-peak load factor %	29%
3. Average monthly Full kWh for Residential NM customer	977
4. DG demand impact index: on-peak kW/MWh	1.47
5. Estimated on-peak kW = Full kWh/(730*29%) - DG MWh x 1.47	

Rocky Mountain Power
Exhibit RMP___(JRS-2R)
Docket No. 14-035-114
Witness: Joelle R. Steward

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

Exhibit Accompanying Rebuttal Testimony of Joelle R. Steward

Example Calculation of Incremental Revenue Deferral

July 2017

Example of Calculation for Incremental Revenue Deferral

Line No.	Year / Month	Reference	2018 / 1	2018 / 2
1	**Actual Schedule 5 Revenue**		$100,328	$164,466
2	**Revenue Under Schedule 1**		$89,683	$147,907
3	**Additional/ (Reduced) Revenue from Schedule 5**	(Line 1 - Line 2)	$10,645	$16,559
4	**Monthly Interest Rate (4.19% Annual)**	Note 1	0.3%	0.3%
5	**Beginning Balance**	Prior Month Line 8	$0	$10,664
6	**Incremental Deferral**	Line 3	$10,645	$16,559
7	**Interest**	Line 4 * (Line 5 + 50% x Line 6)	$19	$66
8	**Ending Balance**	∑ Lines 5:7	$10,664	$27,289

Note:

1 Docket No. 15-035-69 Order to use average of Aaa and Baa corporate bond interest rates

Rocky Mountain Power
Docket No. 14-035-114
Witness: Robert M. Meredith

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

Rebuttal Testimony of Robert M. Meredith

July 2017

Q. Are you the same Robert M. Meredith who sponsored direct testimony in support of the Company's application in this proceeding?

A. Yes I am.

Purpose of Rebuttal Testimony

Q. What is the purpose of your rebuttal testimony?

A. I respond to the direct testimonies of the following witnesses relating to the Company's cost of service analyses in the following order: Utah Clean Energy ("UCE") witnesses Tim Woolf and Melissa Whited; Vote Solar witness Dr. David DeRamus; Vivint Solar witnesses Thomas Plagemann and Richard Collins; The Energy Freedom Coalition of America ("EFCA") witness Eliah Gilfenbaum; Utah Solar Energy Association ("USEA") witness Micah Stanley; HEAL Utah witness Jeremy Fisher; and Division of Public Utilities ("DPU") witness Stan Faryniarz. To the extent separate witnesses made the same arguments, my testimony will address the argument only once but I will note the names of the witnesses who made the arguments. I also present an updated cost of service analysis that reflects some corrections and modifications to address certain issues that were identified through discovery and in response to other parties' direct testimony.

General Discussion of Intervenors' Testimony on the Cost of Service Analysis

Q. What are some of the general themes identified in intervenors' testimony regarding the costs of service analysis?

A. Three major arguments were asserted against the cost of service analysis:

1. A contention that the Company's analysis is too limited because it excludes alleged long-term and societal benefits from private generation.

2. A contention that the Company's analysis is too broad because it considers private generation that is consumed "behind-the-meter".

3. A contention that the Company's analysis is too broad because it considers the shifting of costs from net metering ("NEM") customers to non-NEM customers.

Q. What is your response to these three arguments?

A. Each of these arguments has already been addressed in the Commission's order in this docket issued November 10, 2015. In that order, the Commission established a framework for determining the costs and benefits of the NEM program ("November 2015 Order"). The Commission carefully considered many of these same arguments and concluded in the November 2015 Order that the framework should analyze costs and benefits over a one-year period,[1] include a counterfactual cost of service ("CFCOS") study "that assumes away the existence of net metering customers' power generation, meaning PacifiCorp must meet net metering customers' full load and assume these customers push no energy back to the grid,"[2] and should consider the impacts to "other customers."[3] Further, prior to issuing the November 2015 Order, the Commission issued a July 1, 2015 order ("July 2015 Order") in which, among other things, it made various rulings relating to the applicable statutory provisions and denied a motion to strike. In that order, the Commission stated that:

> [F]or purposes of performing the analysis under Utah Code Ann. § 54-15-105.1(1), the relevant costs and benefits are those that accrue to the utility or its non-net metering customers in their capacity as ratepayers of the utility. Costs or benefits that do not directly affect the utility's cost of service will not be included in the final framework to be

[1] November 2015 Order at 7-8.

[2] *Id.* at ll. 5.

[3] *Id.* at ll. 15; *see also* Utah Code Ann. § 54-15-105.1(1).

established in this phase of the docket.[4]

It also stated that "costs and benefits that are either unquantifiable or not subject to reasonable verification" should not be included in the analysis.[5] The general arguments presented in the intervenors' direct testimony simply attempt to re-argue these issues that have been resolved by the Commission, with no basis for revisiting those issues. The intervenors do not present any new arguments or evidence that would warrant the Commission in revisiting those orders.

Rebuttal of UCE witness Tim Woolf

Q. What are Mr. Woolf's main points in his direct testimony?

A. Mr. Woolf contends that the Company's analysis of the costs and benefits of the net metering program is a "cost shifting" analysis that covers a period that is too short.

Q. How do you respond to Mr. Woolf's contention?

A. Mr. Woolf's contention is very similar to the testimony he filed during the prior phase of this proceeding to set the framework. He makes the same arguments he made in that phase, and continues to ignore the additional costs imposed upon non-NEM customers. The Commission ordered a methodology that considers the impacts to "other customers" as required by Utah Code Ann. § 54-15-105.1(1). The primary cost of the net metering program is the burden placed upon non-participating customers from participating customers who pay far less than their cost of service. Ignoring this reality would undermine the purpose of Utah Code Ann. § 54-15-105.1(1).

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[4] July 2015 Order at 17-18.
[5] *Id.* at ll. 2.

Q. Do you agree with Mr. Woolf that bill credits are not "costs" and do not affect the Company's cost of service?[6]

A. No. Among other things, a cost of service study compares each class' revenue to its cost of service. The results of a cost of service study show what change in revenue is required to bring a particular class from its present level of revenue to full cost of service. Revenue is therefore a major factor in determining a class's cost of service result. The Company's analysis compares the results of the CFCOS to the actual cost of service ("ACOS") and shows that participating customers must pay more to cover their full cost of service, otherwise, costs are shifted to other customers.

Q. Do you agree that private generation should be considered a "utility resource" as Mr. Woolf argues?[7]

A. No. The Company has no control over the installation and operation of private generation. In addition, the Commission has already rejected the argument made by Mr. Woolf in its November 2015 Order when it affirmed that private generation is not a "system resource."[8]

Q. Mr. Woolf contends that, "(b)y constraining the study time horizon to one year (as is done for a typical cost of service study), the analysis fails to account for the ability of distributed generation to avoid or defer long-term system investments."[9] Does the Company's analysis ignore long-term costs?

A. No. While the cost of service analyses do not consider future costs (as they are based

[6] UCE witness Tim Woolf Direct Testimony, ll. 213-34.
[7] *Id.* at ll. 346-52.
[8] November 2015 Order at 13-14.
[9] Woolf Direct Testimony, ll. 438-41.

upon a single year), the analyses do consider lower allocations of facilities which have long lives as a benefit of the NEM program. Mr. Woolf later argues "that the one-year time-frame will only capture a fraction of the costs and benefits of distributed generation, and will fail to capture the longer term benefits associated with avoiding or deferring future utility capital costs."[10] Mr. Woolf has presented no evidence that the Company's analyses that include allocations of long-term facilities would be a "fraction" of a more future looking framework.

Q. Mr. Woolf reasons that, since costs from the NEM program would be borne by shareholders between general rate cases, in the short-term, bill credits associated with the program should not be considered in the costs and benefits analysis.[11] How do you respond?

A. I completely disagree with Mr. Woolf's logic. Although the cost of bill credits will be borne by shareholders in between rate cases, the cost will ultimately be borne by other non-participating customers. Removing bill credits from the calculation of costs and benefits would provide a flawed and inaccurate view of the economics of the NEM program.

[10] *Id.* at ll. 451-53.
[11] *Id.* at ll. 478-518.

Rebuttal of UCE witness Melissa Whited

Q. In her direct testimony, Ms. Whited compares the average per-customer cost to serve residential customers under the cost of service studies the Company prepared. She argues that the average cost to serve all residential customers in the ACOS is $998.77 compared to $999.45 per non-NEM residential customer in the NEM Breakout COS – a $0.68 reduction.[12] Please provide some context for Ms. Whited's comparison.

A. The Commission should consider the different methodologies presented in the ACOS as compared to the NEM Breakout COS. These differences in methodology can make direct comparisons between the results of the ACOS and the NEM Breakout COS challenging. For example, in the NEM Breakout COS, engineering, customer service, and program administration costs are directly assigned to the net metering classes. Understanding the methodological differences between the models explains the apparent higher average cost of service per residential customer in the NEM Breakout COS.

Ms. Whited's comparison shows that the average cost of serving non-NEM residential customers on the NEM Breakout COS is about 0.1 percent more than the average cost of serving all residential customers in the ACOS. Removing the direct assignments from the cost to serve residential NEM customers as filed by the Company shows their average cost of service per residential NEM customer is $930.65, *about seven percent less* than the average cost of serving all residential customers in the ACOS. Removing customers that are less costly to serve (as residential NEM customers

[12] UCE witness Melissa Whited Direct Testimony, ll. 314-38.

are when not accounting for direct assignments) from a class will increase the average per-customer cost of serving that class. The residential class in the ACOS includes both NEM and non-NEM customers. Prior to accounting for direct assignments, the average cost to serve a NEM residential customer is less than a non-NEM residential customer. Therefore removing lower cost NEM customers from the residential class increases the average per-customer cost of service.

Q. Are you suggesting that the direct assignments to the net metering classes in the NEM Breakout COS should be eliminated?

A. No. I adjusted the per-customer cost of service for the residential NEM class to show the driver behind the increase to per-customer cost of service for the residential class between both analyses, which employ somewhat different methodologies.

Q. Is cost of service the only consideration in determining the results from a cost of service study?

A. No. Among other things, a cost of service study examines the difference in revenue relative to cost of service. Both revenue and costs are necessary components to calculate the amount a particular class is either under or overpaying relative to its cost of service.

Q. What do cost of service and revenue per customer show about the impacts to the residential class when NEM customers are removed?

A. Table 1 below compares cost of service, revenue, and changes required to bring the residential class to full cost of service with and without NEM customers as filed by the Company.

Table 1. Comparison of Per-Customer Residential Class Cost of Service Results

	ACOS All Residential	NEM Breakout Non-NEM Residential
Cost of Service (COS)	$753,134,240	$749,260,727
Revenue	$722,768,968	$719,990,943
Customers	754,063	749,673
COS per Customer	$998.77	$999.45
Revenue per Customer	$958.50	$960.41
Change Required to Bring to Full COS	$40.27	$39.04
Difference (COS per Customer)		$0.68
Difference (Revenue per Customer)		$1.91
Difference (Change Required per Customer)		-$1.23

Table 1 demonstrates that the cost of service per residential customer increases when NEM customers are removed, but revenue per customer increases even more, resulting in a smaller change to bring the class to full cost of service. In other words, non-participating customers within the residential class are better off when NEM customers are removed.

Q. Ms. Whited claims that the average benefit attributable to residential NEM customers is $302 per customer and then compares this to a $46 difference in the average cost of serving a residential NEM customer versus the average cost of serving all residential customers.[13] Does this show that benefits exceed costs for the NEM program?

A. No. Ms. Whited's comparison looks at only part of the equation from two different cost of service analyses that have slightly different perspectives. The analysis comparing the CFCOS to the ACOS estimates what the cost of service results would be for each class if the NEM program had not existed. From this analysis, as presented in my

[13] *Id.* at ll. 342-50.

Exhibit RMP___(RMM-1), Ms. Whited calculates that the benefit from NEM program for the residential class is $302 for each NEM customer.[14] Her calculation, however, ignores the largest category of cost – bill credits. When considering bill credits from the NEM program, the analysis shows that the NEM program is a net cost to the residential class of $378 per NEM customer.[15]

The analysis in the NEM Breakout COS examines the characteristics of the NEM customers when they are broken out onto their own classes. The $46 Ms. Whited references, again, only considers part of the relevant information. She is correct that in the Company's original filing the average cost of serving a residential NEM customer, including the one-time costs which the Company is proposing to recover through an application fee, is $46 higher than a non-NEM residential customer. However, she fails to also show that the average revenue from a NEM customer is $328 less. The difference in cost of service result (i.e., the change needed to bring a class to full cost of service) between non-participating residential customers and NEM residential customers is therefore an increase of about $373 per NEM customer.

In summary, Ms. Whited's comparison confuses the two analyses and only considers their results in part. Like her colleague Mr. Woolf, Ms. Whited would like to ignore what NEM customers currently pay for their service, which is what I believe is the core issue for this proceeding.

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[14] On page 3 of Exhibit RMP___(RMM-1), $302 can be calculated by taking $1,659 net cost for residential minus $2,987 cost of bill credits for residential divided by 4,390 residential net metering customers.

[15] *See* page 3 of Exhibit RMP___(RMM-1).

Rebuttal of Vote Solar witness Dr. David DeRamus

Q. Why does Dr. DeRamus conclude that the Company has not demonstrated the costs of the net metering program outweigh the benefits?

A. Dr. DeRamus argues that bill credits from behind-the-meter generation should not be included in costs, since "(a) reduction in revenue is not the same as an increase in costs."[16] He also argues that the Company "ignores a broad range of additional long-term benefits provided by residential DSG."[17]

Q. Should the comparison between the CFCOS to the ACOS consider the bill credits associated with private generation consumed "behind-the-meter"?

A. Yes. In the November 2015 Order, the Commission approved a framework for evaluating costs and benefits under which "(o)ne study creates a counterfactual scenario that assumes away the existence of net metering customers' power generation, meaning PacifiCorp must meet net metering customers' full load."[18] To comply with the Commission's approved framework, both loads and revenues in the CFCOS must reflect the assumption that private generation systems are non-existent. This is true because private generation, whether consumed onsite or exported, cannot presently be interconnected without the NEM program.[19] Excluding behind-the-meter generation from the costs-and-benefits framework, as Dr. DeRamus suggests, would not comply with the Commission's order. Considering the bill credits for private generation consumed behind-the-meter is appropriate, because it is a cost that is borne by other

[16] DeRamus Direct Testimony, ll. 69-76.
[17] *Id.* at ll. 76-83.
[18] November 2015 Order at 5.
[19] Private generation can be interconnected for qualifying facilities, but this generally does not occur for smaller customers.

non-participating customers.

Q. Dr. DeRamus asserts that the parity ratio improves significantly if the exported energy from NEM customers is valued at retail rates consistent with the price that neighboring customers pay for it.[20] Should exports in the NEM Breakout COS analysis be valued at retail rates?

A. No. The retail rates customers pay include recovery of the fixed costs associated with their connection to the grid and the costs of providing the 24/7 supply that they require. In the Company's NEM Breakout COS study, exports were given a value based upon the net power cost analysis that Mr. Michael G. Wilding prepared, as adjusted for line losses.[21] This is an accurate estimate of the benefit to other customers of this exported energy during the study period. Further, in its November 2015 Order the Commission ordered that "PacifiCorp should not assign a price or value to the net metering customers' excess energy other than as recognized in the net power cost analysis." [22]

Q. Dr. DeRamus argues that the Company has not demonstrated that there are incremental costs associated with the engineering review for interconnections, because the Company must also review new loads requests.[23] Do you agree?

A. No. While I agree that the Company must also review new load requests to ensure safe and reliable provision of power, that review does not eliminate the incremental costs of engineering review for interconnections. A request for interconnection of a private generation facility represents incremental workload above and beyond what is required

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[20] DeRamus Direct Testimony, ll.748-50.
[21] Robert M. Meredith Direct Testimony, ll. 463-69.
[22] November 2015 Order at 9.
[23] DeRamus Direct Testimony, ll. 758-67.

for new service requests. Exhibit RMP___(RMM-8) shows the Company's estimated engineering cost of interconnection requests reviews for the study period. In fact, Dr. DeRamus concedes as much when he asserts that it would likely take *more time* to review interconnection requests than requests for new load.[24] He then argues that such costs should be recovered through an application fee,[25] which is precisely what the Company has proposed.

Q. Do you agree with Dr. DeRamus' and Mr. Stanley's recommendation that the system upgrades which NEM customers have paid for should be considered a benefit of the net metering program?[26]

A. No. When NEM customers interconnect to the Company's system, by Commission rule they pay the full cost of system upgrades that are required to safely and reliably interconnect their private generation. Absent the customer's choice to install a private generation facility, those costs would not occur.

Q. Dr. DeRamus makes specific adjustments to the Company's CFCOS compared to ACOS analysis and concludes that the net metering program is a net benefit to residential customers of about $200,000.[27] Does his view of the costs and benefits of the net metering program make sense?

A. No. Dr. DeRamus removes bill credits associated with behind-the-meter consumption and costs that he considers uncertain to arrive at his $200,000 net benefit figure. I disagree with both of these recommendations for the reasons expressed above. I would

[24] *Id.* at ll. 768-73.
[25] *Id.* at ll. 773-74.
[26] *Id.* at ll. 775-88; Stanley Direct Testimony, ll. 93-98.
[27] DeRamus Direct Testimony, ll. 811-24.

note, however, that his alternative view of costs and benefits is particularly skewed and one-sided in that it excludes the cost associated with bill credits from private generation consumed onsite, but fails to consistently exclude the benefits associated with private generation consumed onsite.

Q. Dr. DeRamus characterizes the Company's load research study as "statistically insufficient and unreliable."[28] Do you agree?

A. No. The Company adheres to generally accepted sampling procedures used throughout the industry. A confidence level of 90 percent and precision of plus or minus 10 percent is generally accepted as a minimum standard. The Company's residential net metering sample was designed at the 95 percent confidence level with plus or minus 10 percent precision. Additional sample sites were added to enhance the study and properly deal with population growth and unexpected data problems. To achieve a 95 percent confidence level with plus or minus 10 percent precision, the Company's sampling procedures indicated that 45 sites would be required. The Company's load research study exceeded this level by relying upon 52 sites.

[28] *Id.*, at ll. 906-8.

Q. Dr. DeRamus states that "RMP has not collected detailed data on NEM customers' usage before and after installing solar systems – which is particularly important in assessing how these systems have caused their use to change, e.g., in reducing their peak load."[29] Do you think that analyzing pre- versus post-interconnection loads is the appropriate way to understand the usage characteristics of net metering customers?

A. No. An examination of loads pre- and post-interconnection is not a reliable way to measure the production from a customer's private generation system. The pre-interconnection and post-interconnection periods may include different weather and different usage patterns for each customer. The best way to evaluate the incremental load profile and exports of net metering customers is to use a load study of private generation metering the production from each customer's facility, as the Company has done.

Q. Dr. DeRamus contends that the Company's load research study is not valid because it was put in place in December 2014 when the population of residential net metering customers was only 1,578 and that population has since grown to about 19,000.[30] Does the rapid population growth disqualify the study?

A. No. Populations of customers are always evolving. To examine the load characteristics of a population, it is necessary to develop a sample based upon the population from a snapshot in time. Further, the Company's load research study remains valid, since about the same number of overall sample sites is needed to maintain a statistically defensible

[29] *Id.*, at ll. 912-15.

[30] I*d.* at ll. 918-34.

study. If the load research study were designed based upon the population of 16,335 residential net metering customers as of December 2016, the Company's sampling procedures indicate that 44 sites would be required to achieve 95 percent confidence with a plus or minus 10 percent precision as compared to the 45 sites that were required for the study that was based upon the population in 2014.

Q. Why would fewer sites be needed for a load research study based on the population in 2016, when the overall population has grown so much?

A. The Neyman allocation procedure determines the minimum size required to achieve a certain confidence level at a certain level of precision based upon the standard deviation and the size (customer count) of a given population. While overall size is a factor in the calculation, the standard deviation of a population has a far greater influence on the number of sites required. The standard deviation of the population declined considerably between the customers in place as of December 2016 and the customers in place as of December 2014. The increase in population was therefore tempered by the decrease in standard deviation of the sampling variable which resulted in a sample size that was about the same for a study based upon the 2016 population as compared to the 2014 population.

Q. Would it be reasonable for the Commission to reject the Company's analyses simply because its load research study is based upon a population that has grown?

A. No. The population of residential net metering customers has been growing rapidly for the last several years. If the growth of net metering needs to stabilize in order for the Company to put a load research study in place, it may be many more years before the Company could do so. Dr. DeRamus, and most of the other intervenors, offer numerous arguments, many of which appear to be a clear attempt to delay a Commission decision on the costs and benefits of net metering. But the evidence is clear that residential net metering customers pay far less than their cost of service now. There is no legitimate reason to delay a decision to rectify this situation.

Q. Dr. DeRamus advocates for a methodology in which the costs and benefits of the net metering program would be based upon a long-term analysis that includes social and environmental benefits.[31] How do you respond?

A. As I discussed above, the Commission has already addressed and rejected that position for evaluating net metering.

Rebuttal of Vivint Solar witness Thomas Plagemann

Q. Mr. Plagemann argues that there is no basis for evaluating private generation differently than other technologies such as LED lights.[32] Do you agree?

A. No. The Utah legislature passed a law requiring the Commission to make a finding of the costs and benefits of the NEM program.[33] The Commission subsequently opened this docket to investigate and establish a framework for evaluating the costs and benefits of the NEM program. In the prior phase of this proceeding, Company witness Joelle R. Steward presented evidence that the NEM program should not be evaluated in the same manner as demand-side management. I will not repeat those arguments here. For more detail, please refer to pages 13 through 15 of Ms. Steward's direct testimony in the last phase of this proceeding dated, July 30, 2015. The Commission heard those arguments and issued the November 2015 Order approving a framework

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[31] *Id.* at ll. 1099-1190.
[32] Plagemann Direct Testimony, ll. 59-69.
[33] Utah Code Ann. § 54-15-105.1(1).

for evaluating costs and benefits that did not include the traditional costs and benefits tests used to evaluate demand side management.

Q. Mr. Plagemann cites an article by Berkeley professor Dr. Wolfram as evidence that there may be as much cost shifting from LED lights as there is with net metering. Does this article have any relevance to this proceeding?

A. No. In her article, Dr. Wolfram generically discusses the overall change in revenue to California utilities from NEM as compared to LED light installations. That article is not relevant to this proceeding. There are key differences between NEM and demand side management other than their revenue impacts which the Commission considered and found to be persuasive. For example, a customer employing conservation measures will never be able to zero out energy charges in the same way that a rooftop solar customer can under the current NEM program.

Q. Mr. Plagemann characterizes the Company's analysis as an "unproven presumption of a cross-subsidization, structured under the guise of a specious cost shifting argument."[34] Please respond.

A. In my direct testimony, I presented both cost of service analyses offered in compliance with the November 2015 Order. These analyses were based upon substantial data and are an accurate estimate of the costs and benefits of the NEM program. Mr. Plagemann provides no evidence that the Company's analyses are either "unproven" or "specious."

[34] Plagemann Direct Testimony, ll. 61-62.

Rebuttal of Vivint Solar witness Richard Collins

Q. Mr. Collins references the present value of revenue requirement difference between a high private generation sensitivity case and a base sensitivity case from the 2015 Integrated Resource Plan ("IRP") and concludes, as does HEAL Utah witness Mr. Fisher, that this results in a net benefit associated with residential solar.[35] Do you agree?

A. No. The IRP sensitivities are not a net benefit analysis. Private generation is modeled as a reduction to load without any assignment of the incremental cost of private generation that non-participating customers pay in the form of bill credits. Also, the IRP is used to prepare a long-term resource plan that is based on a 20-year planning horizon. To this end, the IRP sensitivity studies also capture potential changes to long-term system costs that are increasingly uncertain over the 20-year forecast used for any given IRP. Those potential benefits, such as lower fuel costs, are subject to change with the underlying market conditions relative to what was assumed in a 20-year forecast used for any given IRP. For example, in the 2015 IRP, the change in nominal levelized system costs calculated over a 20-year period between the low private generation sensitivity and the base case was $74 per megawatt hour.[36] A comparison of this same value in the 2017 IRP yields a nominal levelized value of $58 per megawatt hour, which is a 22 percent reduction relative to the 2015 IRP. A determination of the costs and benefits of NEM should not rely upon the difference between a pair of IRP sensitivity runs, because they include benefits that are anticipated many years into the future. Here

[35] Collins Direct Testimony, ll. 193-99; Fisher Direct Testimony, pp. 14-15.
[36] *See* 2015 IRP, Vol. 1 at 199.

the Commission made the right decision to only consider a one year test period in its November 2015 Order. The framework that the Commission adopted is useful for rate setting and avoids intergenerational inequities that would be associated with ascribing value for potential benefits outside of the time horizon to set rates.

Q. Mr. Collins states that "(i)f bill credits are removed from 'costs' to service a residential NEM customer the result is that a residential NEM customer covers approximately 92 percent of its cost of service."[37] Please describe what this 92 percent figure represents.

A. Mr. Collins modified the NEM Breakout COS study so that bill credits along with the net power cost analysis value associated with excess energy are eliminated. The calculation of this 92 percent figure is more fully described in EFCA witness Mr. Gilfenbaum's direct testimony.[38]

Q. Should the compensation for exported energy be ignored in the NEM Breakout COS as Mr. Collins recommends?

A. No. One of the most important elements of the NEM program is the netting and banking of energy. The Company's NEM Breakout COS appropriately considers the impact to revenue and value of excess energy. Without doing this, any evaluation of the NEM program would be incomplete and would ignore the reality that exists under the program.

[37] Collins Direct Testimony, ll. 309-11.

[38] Gilfenbaum Direct Testimony, ll. 208-48.

Q. Mr. Collins also recommends that the bill credits associated with production consumed onsite should be ignored in the comparison between the CFCOS to the ACOS.[39] Please comment.

A. Again, the Company's analysis complies with the methodology established in the November 2015 Order and appropriately considers private generation consumed onsite. All private generation, both exported and used behind-the-meter, exists only because of the NEM program.[19]

Q. Mr. Collins claims that the Company's analysis does not consider the salvage value or the benefit of meter redeployment in its analysis that compares the CFCOS to the ACOS.[40] Is this accurate?

A. No. The Company's estimate of the cost to install a new meter capable of measuring the bi-directional flow of energy in the CFCOS is an incremental cost that assumes the existing meter will be redeployed. For example, the materials cost of a meter capable of measuring bi-directional energy flows for a residential customer installed in 2015 was reduced by the materials costs of $31.81 for a standard residential meter. The cost to install a meter includes both labor and material. Mr. Collins' reference to $107 as the incremental value of redeploying the existing meter is inaccurate because it includes labor.

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[39] Collins Direct Testimony, ll. 332-57.
[40] *Id.* at ll. 358-68.

Q. Mr. Collins argues that using the fully loaded hourly cost of a field engineer is not an accurate way to estimate the incremental cost of engineering, since some of those fully loaded costs might be fixed and not truly incremental.[41] Is the Company's estimate an appropriate way to measure the incremental cost of engineering?

A. Yes. It is appropriate to include the full cost of an engineer including that employee's benefits. The Company's estimate of engineering costs related to the NEM program includes over 3,000 hours of employee time for the 2015 study period.[42] This is greater than a full-time equivalent employee who works 2,080[43] hours in a year. The benefits along with the salary are therefore appropriately considered as incremental.

Q. Mr. Collins also argues that "(a)nother weakness of the method is that it does not recognize that there will be efficiency gains through learning by doing. As more applications and connection studies are done, workers will become more efficient at processing them and thus average costs will decline."[44] How do you respond?

A. In theory, Mr. Collins is correct. The Company is always seeking efficiencies in the work it performs. However, the Company must prepare its estimates of different costs for a discrete period of time in order to comply with the November 2015 Order. It is also important to consider that the 2015 study period and after included a significant volume of NEM applications and interconnections. The employees who were

[41] *Id.* at ll. 383-89.

[42] *See* Exhibit RMP___(RMM-8). 3,269 total hours can be computed by multiplying "Application Review Time (Hours)" by "2015 Applications."

[43] 8 hours a day times 5 days a week times 52 weeks in a year equals 2,080 hours in a year. This does not include holidays and personal time.

[44] Collins Direct Testimony, ll. 391-94.

reviewing and processing these applications and interconnections were therefore not dealing with them on a "one-off" basis where it might be expected that their efforts would be less efficient. I do not anticipate that there are any material gains in efficiency for this work that should be incorporated into the analysis.

Q. Mr. Collins claims that "RMP expects to automate its net metering billing system in the future and when they do, the costs associated with billing NEM customer will be a fixed cost that will not change with additional residential Net metering customers."[45] Is this an accurate statement?

A. No. The Company has no immediate plans to update its system for billing NEM customers.

Q. Is Mr. Collins' statement that "RMP has recognized the following as benefits (i) avoided plant O&M costs, (ii) avoided transmission and distribution costs, (iii) avoided capacity investment, and (iv) increased grid resiliency; however, RMP did not take them into account in its analysis,"[46] correct?

A. Not entirely. The Company's analyses include reductions to some of these costs as a benefit in the form of lower inter-jurisdictional allocation factors. Including speculative future benefits is outside of the scope for the framework that the Commission required in its November 2015 Order.

Q. Do you agree with Mr. Collins that the CFCOS should consider the increased cost of additional generation variable operations and maintenance ("VOM")?[47]

A. Yes. The Company has modified its CFCOS to include this benefit for the NEM

[45] *Id.* at ll. 397-400.
[46] *Id.* at ll. 407-10.
[47] *Id.* at ll. 498-503.

program. The benefit associated with generation VOM is about $0.46 per megawatt hour. The calculation of this benefit is described in Mr. Wilding's rebuttal testimony.

Q. In his direct testimony, Mr. Collins states that if the Company used a seven percentage reduction to its peak, then the Company's analysis "would over allocate generation and transmission at the jurisdictional, state and class level."[48] Did the Company only reduce its peaks by seven percent?

A. No. Mr. Collins seems to confuse Mr. Douglas L. Marx's analysis with my analysis. Mr. Marx intended to illustrate why private generation "does not reduce the peak demand on the distribution system to a degree that could warrant a reduction in infrastructure."[49] His estimates of peak reduction presented in his direct testimony do not feed into the cost of service analyses I presented.

The demand-related allocation of fixed generation and transmission costs in the Company's cost of service studies is based upon loads that occur at the same time or coincidently with the Company system peaks during each of the 12 months during the year. The capacity contribution (relationship of peak reduction to nameplate capacity) from this perspective is 24 percent for the 2015 study period. Exhibit RMP___(RMM-1R) shows the derivation of this 24 percent value.

[48] *Id.* at ll. 592-95.
[49] Douglas L. Marx Direct Testimony, ll. 27-29.

Q. Mr. Collins describes an adjustment he made where he expanded system coincident peak loads by seven percent and then reduced them by 47 percent consistent with a capacity planning contribution value from the 2017 IRP.[50] Is this an appropriate approach to determining the demand-related allocator for a cost of service model?

A. No. The Company's demand-related allocator for generation and transmission costs appropriately considers the load from each customer class at the time that the Company's system peaks in each of the 12 months of the year. These loads were not adjusted by seven percent. They reflect the Company's estimates of class loads during those specific times. Mr. Collins' recommendation to adjust these loads by 47 percent does not make any sense.

First, the capacity contribution study from the Company's IRP is used for resource planning purposes to determine the level by which large utility scale variable energy resources can be relied upon to meet the Company's capacity requirements. I do not think this value should be conflated with cost of service allocations.

Second, even if it were appropriate to modify cost of service allocations by this value used for resource planning, Mr. Collins' approach is mathematically incorrect in at least two ways. First, he determines his 47 percent load reduction value by taking one minus the capacity contribution.[51] This makes no sense. Capacity contribution measures the ability of a variable energy resource to serve the Company's capacity need reliably. The higher the capacity contribution, the greater a resource's ability to reliably

[50] Collins Direct Testimony at lines 668-82.

[51] *Id.* at ll. 641-42.

serve a capacity need. Under Mr. Collins' methodology, resources that have a very low capacity contribution would reduce peak demand even more. Second, Mr. Collins reduces what he believes[52] to be total full requirements load by 47 percent. This application of capacity contribution also makes no sense because a capacity contribution value is not applied to load, but rather to the nameplate capacity of a variable energy resource. Finally, Mr. Collins does not use the final capacity contribution value from the 2017 IRP. The capacity contribution for a fixed tilt photovoltaic resource in the East balancing authority in the 2017 IRP is 37.9 percent, not 53 percent.[53]

Q. In his direct testimony, Mr. Collins asserts that "(h)owever, what the Commission has done by adopting a cost of service allocation study methodology to evaluate the cost and benefits of a net metering program is to leave out of the analysis what is arguably the most important stage, the determination of revenue requirement."[54] Is his statement accurate?

A. Not at all. In the November 2015 Order, the Commission required the costs and benefits analysis to "reflect costs at the system, state and customer class level."[55] In compliance, the Company prepared two cost of service models and two jurisdictional allocation models ("JAM") which show two sets of revenue requirements reflecting the assumptions of the existence and non-existence of private generation.

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[52] It is not full requirements load, because he expands it by a seven percent value that was never used in these studies.
[53] *See* 2017 IRP, Vol. II, Table N.1 at 316.
[54] Collins Direct Testimony, ll. 788-91.
[55] November 2015 Order at 16.

Q. Like other witnesses, Mr. Collins argues for considering future benefits for the net metering program.[56] Does he present any new or different arguments from other witnesses?

A. No. The costs and benefits of the NEM program should not include future or societal benefits for the same reasons I have already discussed.

Q. How do you respond to Mr. Collins' comment that "it is unknown whether the 52 sample is representative or not in terms of the strata"?[57]

A. Even after some sites were removed from the study, the load research study meets the minimum requirement of 90 percent confidence at 10 percent precision for all strata. For a study that meets 95 percent confidence at 10 percent precision, the size of the sample meets the requirements for three out of the four strata. On the one stratum under which the size does not meet this higher standard, it is important to note that the stratum has only a three-percent weighting in determining the overall class profile. Table 2 below compares the size by strata of the Company's load research study versus both levels of confidence:

Table 2. Load Research Sample Sizes by Strata

Strata	Strata Boundary	Residential Net Metering Study	Strata Weighting	Size Needed for 90% Confidence at 10% Precision	Size Needed for 95% Confidence at 10% Precision
1	0 -400 kWh	16	35.7%	9	12
2	401 - 900 kWh	11	46.2%	7	10
3	901 - 2,000 kWh	14	15.1%	6	8
4	> 2,000 kWh	11	3.0%	11	15
Total		52	100.0%	33	45

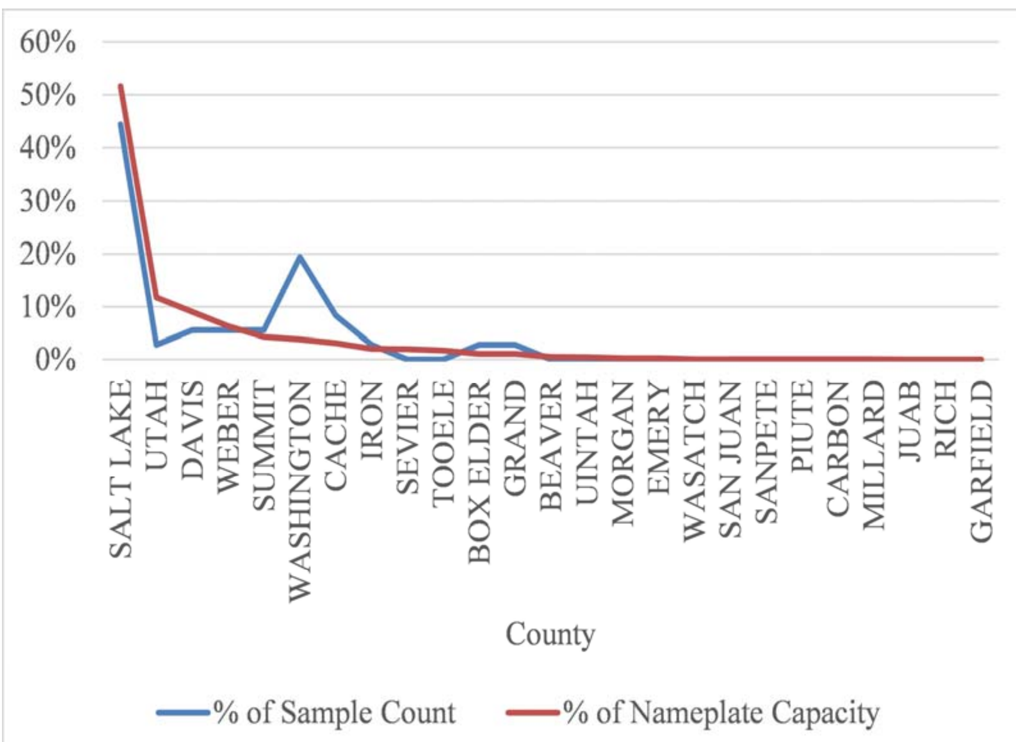
[56] Collins Direct Testimony, ll.792-848.

[57] *Id.* at ll. 442-43.

Q. Mr. Collins criticizes the Company's private generation production study because it contained only one sample for some counties and, from a statistical perspective, that sample could be an outlier.[58] Is the production study invalid because it contains only one sample point from some counties?

A. No. None of the 36 production meters exhibited outlier status. Generally, the Company's private generation production study included more samples in those counties that had a greater share of total interconnected capacity in the Company's service territory. The study also included few or even no samples for those counties that had a smaller share of total interconnections. Figure 1 below shows the proportions of sample count and interconnected nameplate capacity by county.

Figure 1. Production Study Sample Count Compared to Interconnected Capacity by County



[58] *Id.* at ll. 445-53.

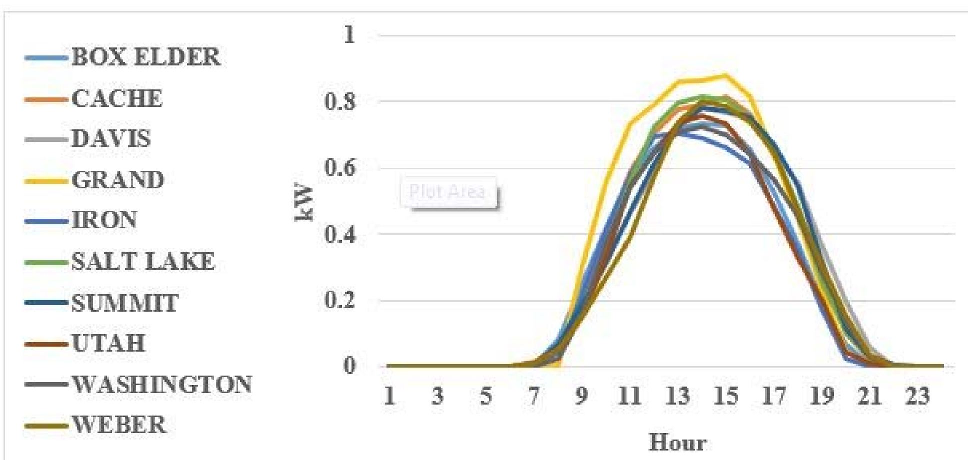
The Company's standardized production profile was developed using samples from various counties and weighting the data from those counties by interconnected capacity in each county. For those counties that have more significant interconnected capacity, the sample size is higher. For those counties with less significant interconnected capacity, few or even no sample sites were installed.

County segmentation was employed because one part of the state may be sunny at the same time that another part is cloudy. Latitude also impacts the length of days throughout the different seasons of the year. For example, days are slightly longer in Ogden than they are in Moab during the summer.

Q. How does the data from different counties compare to one another?

A. While there are differences in the solar profiles between counties, solar generation profiles within the state are relatively predictable and exhibit similar shapes. Figure 2 below shows the average hourly loads by county for the peak month of June.

Figure 2. Average Hourly Loads by County in June (1 kW)



Q. Mr. Collins argues that the Company load research study was not weather normalized.[59] Is this accurate?

A. Not entirely. The load research study for NEM residential customers was treated like any other load research study. The profile was based upon actual data from sample meters and expanded to the weather normalized energy for the class. This accounts for the overall volume of load for the class, but reflects the actual weather events that occurred in the period. The profile itself must be based upon actual weather because the different monthly peaks often coincide with extreme weather events. Class loads should accurately reflect actual conditions on those peak days.

Q. Mr. Collins notes that solar production may have been abnormal for the calendar year 2015 period.[60] Does this mean that the Company's analyses "should not be used as the basis for rate policy or rate setting"?

A. No. I think it is reasonable to use the actual private generation production data to capture the real conditions that occurred during each hour of the period. Doing so ensures that the interaction between solar production output and customer loads is accurately captured for peak days.

Q. The estimated profile for a solar private generation system in a typical meteorological year is available from National Renewable Energy Laboratory's online PVWatts® calculator. How might using this data impact the Company's finding that the costs exceed the benefits for the NEM program?

A. I prepared an analysis showing that a normalized solar production profile that uses

[59] Collins Direct Testimony, ll. 687.
[60] Collins Direct Testimony, ll. 461-81.

typical meteorological year data would not alter the finding that costs exceed the benefits, nor would it significantly change the magnitude of the net cost to Utah customers of the NEM program. The Company created a composite production profile by taking profiles from the PVWatts® calculator for the 10 counties from which the Company had installed production meters and applying the same weighting ("TMY production profile). The 12 system coincident peaks for the TMY production profile were then compared to the standardized production profile that is based upon the Company's actual data. The sum of private generation at the time of the 12 monthly system coincident peaks was 1.4 percent lower for the TMY production profile than for the Company's standardized production profile. The system coincident peaks are a primary driver for inter-jurisdictional allocations. For simplicity, I did not input the impact of the TMY production profile through the CFJAM model and run those values through the CFCOS, but instead examined what costs and benefits at the state level as shown on page 2 of Exhibit RMP___(RMM-1) to my direct testimony would be if the inter-jurisdictional allocation benefit were reduced by 75 percent of the 1.4 percent difference. The system generation factor is the primary allocator of cost in the JAM model and is calculated by a weighting of 75 percent for 12 system coincident peaks and 25 percent for energy. Making this change would increase the net cost of the net metering program included in my direct testimony by 0.8 percent or by about $0.32 per megawatt hour.

Q. Do you recommend using the PVWatts® calculator to calculate solar production profiles instead of the Company's standardized production profile?

A. No. My analysis was used to show that normalizing solar output would not materially change the Company's analyses. I continue to believe that using actual solar production data from the Company's NEM customers for an actual year is more appropriate.

Rebuttal of EFCA witness Mr. Eliah Gilfenbaum

Q. In his direct testimony, Mr. Gilfenbaum states that "(t)he COS study framework is limited in that it looks only at the short-term recovery of embedded costs."[61] Similarly, HEAL Utah witness Mr. Fisher, claims that the cost of service framework "allocates distributed generation its lowest possible value—the value of avoided energy only."[62] Do you agree with their characterizations?

A. I agree that a cost-of-service-based framework considers only costs and benefits that occur in a single year and therefore do not include potential costs and benefits that may occur decades in the future. However, it is important to recognize that the analyses in my direct testimony still confer significant value to the NEM program, since they include reductions in allocations of Company facilities, many of which are expected to be in service for many years to come, along with the benefit of more short-term incremental net power costs. Thus, characterizing these analyses as "short-term" does not do them justice for the level of benefits that they provide.

Q. Mr. Gilfenbaum prepared an analysis that estimates what the parity ratio would be in the NEM Breakout COS for the residential NEM class if the bill credits and the value of exported energy were excluded from the study.[63] Was his approach for determining this parity ratio reasonable?

A. Yes. I think that Mr. Gilfenbaum's calculation, which shows that the residential NEM

[61] Gilfenbaum Direct Testimony, ll. 112-13.
[62] Fisher Direct Testimony, p. 4, ll. 10-11.
[63] Gilfenbaum Direct Testimony, ll. 208-48.

class would be at a 91.6 percent parity ratio if exported energy were ignored, is reasonable.

Q. Should the Commission exclude from consideration exported energy from the NEM Breakout COS?

A. No. Mr. Gilfenbaum's analysis shows that the banking and crediting of exported energy at retail energy rates is the key contributor to the cost shifting that occurs with the NEM program. It is critical for the Commission to consider the value of and the compensation paid for excess energy to make a determination of the costs and benefits of the NEM program. Mr. Gilfenbaum's calculations demonstrate that providing the appropriate value for exports is critical to ensuring that both NEM customers are adequately compensated and all non-participating customers do not pay excessively. Further, his calculation supports the alternative NEM successor program that the DPU and OCS raise in their direct testimony, which is discussed in more detail by Company witness Ms. Steward in her rebuttal testimony.

Q. Mr. Gilfenbaum recommends modifying the allocation of distribution line transformers for the residential NEM class to be based upon the class' July non-coincident peak instead of the maximum for all months in the NEM Breakout COS.[64] Likewise, DPU witness Mr. Faryniarz describes how the class monthly maximum non-coincident peak allocator may cause a double counting of transformer costs for the residential NEM class.[65] Do you agree with Mr. Gilfenbaum's proposed modification and will this take care of Mr. Farniarz's concern?

A. Yes. The Company agrees to modify its allocation of distribution line transformers for the residential NEM class to be based upon non-coincident peak in the month of July for this proceeding. If the Commission orders separate class treatment for residential NEM customers, the Company reserves the right to recommend something different for line transformer allocations based upon the data for this class. I believe that this also addresses any concerns of double counting for these costs that Mr. Faryniarz expresses.

[64] *Id.* at ll. 256-87.
[65] Faryniarz Direct Testimony, ll. 735-50.

Q. Mr. Gilfenbaum notes that the average number of customers per transformer is higher for residential NEM customers than for non-participating customers, causing the coincidence factor and consequent distribution line transformer cost allocation to be higher (0.82 coincidence factor instead of 0.76 coincidence factor for non-participating residential customers). He then recommends that the coincidence factor for NEM customers be set to the same level as non-participating customers because he posits that having a customer with rooftop solar "on a given transformer would likely increase load diversity." Do you agree?

A. No. The coincidence factor used for residential NEM customers correctly reflects the number of customers within this class who share a transformer on average. Using a coincidence factor to adjust the allocation of line transformers based upon the number of customers per transformer appropriately reflects cost causation, since line transformers are sized based upon this criteria. While the fewer number of customers per transformer for residential customers with private generation may be more an indication of those customers' housing type (potentially larger homes that are single family) than their private generation per se, this cost causative characteristic reflects the service that is provided to these customers. To separately determine cost of service for NEM customers, as was done in the NEM Breakout COS study, requires examining all of the characteristics used in cost of service models regardless of whether those characteristics are directly related to the customers' private generation or not.

Further, Mr. Gilfenbaum provides no evidence to support his assertion that there is greater load diversity for rooftop solar customers. He also provides no evidence of any benefit associated with having a NEM customer on a line transformer that would allow a less costly transformer to be installed than would otherwise exist. In fact, Company witness Mr. Marx's direct testimony demonstrates that private generation does not decrease localized infrastructure.

Q. Mr. Gilfenbaum notes that the line transformer allocator for the overall residential class in the ACOS is 60.4454 percent and is 60.5216 percent for both the NEM and non-NEM residential classes in the NEM Breakout COS and concludes that this difference is driven by greater diversity for the combined class.[66] Do you agree?

A. I agree that the allocator for line transformers is higher for all residential customers when NEM customers are broken out separately as they were in the NEM Breakout COS study. Instead of an impairment of diversity, this difference is primarily related to the cost of service methodology wherein class monthly maximum non-coincident peak is used to allocate line transformers and this value occurred in a different month for NEM customers (December instead of July). The Company agrees to modify the allocation of line transformers in the NEM Breakout COS for residential NEM customers for this proceeding to be based upon non-coincident peak in July. After making this change, the combined allocator for all residential customers is virtually identical in the ACOS and NEM Breakout COS (60.4564 percent for NEM Breakout COS compared to 60.4589 percent for ACOS or about a 0.004 percent difference).

[66] Gilfenbaum Direct Testimony, ll. 352-66.

Q. Mr. Gilfenbaum argues that the Commission's framework "demonstrates the change in how costs are allocated (i.e., how the pie is sliced), but it fails to show how NEM generation affects overall system costs (i.e., reducing the size of the pie that is shared)."[67] Please comment.

A. A large portion of the benefit of the NEM program in the analysis is related to the reduction in inter-jurisdictional allocations related to private generation. I agree that this benefit category does not consider a reduction in overall system costs (the overall size of the pie), but rather a reduction in allocations (how the pie is sliced) to Utah customers. However, total system costs or the total size of the pie in the CFCOS is reduced to reflect lower overall net power costs.

Also, the benefit of lower inter-jurisdictional allocations does not include future costs, but it should not be considered a short-term benefit, since it includes the allocations of facilities that are expected to be in service for many years to come. This benefit is significant and represents $30.03 per megawatt hour.[68]

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[67] *Id.* at ll. 448-450.

[68] *See* page 2 of Exhibit RMP___(RMM-2R). $1,588,000 lower interjurisdictional allocation benefit divided by 52,877 megawatt hours of net metering energy production equals $30.03 per megawatt hour.

Q. Mr. Gilfenbaum also makes the statement that "(i)f every region within PacifiCorp's territories had the same level of penetration of NEM generation, and therefore contributed to reducing coincident system peak to the same extent, then the benefit associated with jurisdictional allocation would be zero in all areas."[69] Did the Company's analysis consider the jurisdictional impacts related to the NEM programs in other states?

A. No. The CFJAM, which was used to determine the reduced inter-jurisdictional allocation benefit, only considered the non-existence of Utah's NEM program. Demand and energy were not reduced for other states to assume that their NEM programs were not in existence. The Company's analysis therefore appropriately reflects the impacts to the Company's Utah customers of the Utah NEM program.

Q. Mr. Gilfenbaum recommends that the value of exported energy include a benefit for future carbon dioxide ("CO_2") emissions compliance.[70] Would this value be appropriate to include in the analysis of costs and benefits ordered by the Commission?

A. No. The Company does not currently have an obligation to comply with any CO_2 emissions compliance taxes or rules for its Utah customers. It would be inappropriate to include this benefit since it is unknown and speculative. In its July 2015 Order, the Commission stated that "(c)osts or benefits that do not directly affect the utility's cost of service will not be included in the final framework to be established in this phase of the docket."[6]

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[69] Gilfenbaum Direct Testimony, ll. 451-55.
[70] *Id.* at ll. 497-534.

Q. Mr. Gilfenbaum also recommends providing a value to exported energy for avoided generation capacity.[71] Please comment.

A. The Commission, in is November 2015 Order, concluded that the framework for determining costs and benefits should consider a one-year period.[3] The benefits that Mr. Gilfenbaum recommends be included in the valuation of exports fall outside of this period.

Q. Mr. Gilfenbaum computes a benefit related to marginal transmission and distribution costs.[72] Is his calculation reasonable?

A. No. Even if potential future benefits were a part of the framework the Commission ordered, his approach for estimating marginal transmission and distribution benefits is not reasonable. Mr. Gilfenbaum uses what is described as the "Functional Subtraction Approach" from the NARUC Electric Utilities Cost Allocation Manual to create a linear regression between load growth and transmission and distribution capital additions from FERC Form 1 filings. This approach to estimate future transmission and distribution deferral from rooftop solar is highly suspect. First, a correlation between capital additions and increases in load does not necessarily mean causality. Over time loads grow and the Company invests in its distribution and transmission systems. New investments may be made to comply with stricter reliability standards and have nothing to do with load growth. New transmission investments may also be related to connecting diverse resources such as wind with the Company's system and may also have nothing to do with load growth. Second, the presence of growth-related

[71] *Id.* at ll. 538-709.
[72] *Id.* at ll. 755-833.

transmission and distribution investments does not mean the Company's future investments are deferrable by rooftop solar. As Company witness Mr. Marx demonstrates in his direct testimony and rebuttal testimonies, rooftop solar is not able to reduce distribution investment at low levels of penetration and may even increase it at higher levels of penetration.

Rebuttal of USEA witness Micah Stanley

Q. Mr. Stanley argues that a one-year period is insufficient to measure the costs and benefits of the NEM program because that year could be an "outlier" and the "benefits of solar grow over a long period of time."[73] How do you respond?

A. Given the growth in private generation penetration, I expect there will be some degree of evolution for this group of customers. Mr. Stanley is correct to assume that private generation prices are dropping precipitously and the technology for photovoltaic systems are likewise experiencing advancement. It is also important to consider, however, that the ultimate source for the vast majority of this private generation, the sun, continues to do what it has always done, rising and setting at specific times throughout the year for any given longitude and latitude. While I expect overall penetration to increase, the results of the Company's cost of service studies based upon the 2015 study period can be extrapolated to the present population level. Mr. Stanley has provided no evidence that 2015 was an outlier. Like other parties, Mr. Stanley offers various conclusory arguments to try to challenge the Company's analysis and delay a determination on the relevant issues, but he offers nothing that would change the central reality - that residential NEM customers pay less than their cost of service.

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[73] Stanley Direct Testimony, ll. 61-78.

Q. How do you respond to Mr. Stanley's assertions that the "Company's methodology is materially flawed because it relies on data gathered from a small sample of single meters while excluding significant benefits of the NEM program. It also appears that the Company did not take a sample group as a control for the analysis of the NEM vs. non-NEM customers"?[74]

A. Again, the Company's load research study includes a sample of customers that meets or exceeds industry standards. Also, Mr. Stanley's claim that the Company does not have a control group for "non-NEM customers" is incorrect, since it has a load research study in place for all residential customers.

Q. Is Mr. Stanley's claim that the Company did not consider the benefits of "producing energy locally at the point of consumption"[75] accurate?

A. No, not at all. The Company's analyses attribute a benefit of total line losses to NEM customers. If anything, the Company's assumption that all line losses are avoidable from private generation is conservative, since it includes both load and no-load losses and does not assume any additional losses for energy that is exported, and would in reality travel through the Company's facilities experiencing losses as it finds load on another site to serve.

Q. Is there any basis for including a benefit to the NEM program for new "smart" meters as Mr. Stanley recommends?[76]

A. No. The Company does not presently install "smart" meters in its Utah service territory.

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[74] *Id.* at ll. 79-82.
[75] *Id.* at ll. 99-110.
[76] *Id.* at ll. 125-32.

Q. Is Mr. Stanley's statement concerning incremental administrative expense that "$198,000 was attributable to inquiries and administrative times answering questions around NEM Programs"[77] correct?

A. No. The Company attributes a cost of approximately $198,000 to administer the NEM program for residential customers.[78]

Q. What portion of incremental costs in the analysis that you present is related to answering inquiries related to net metering NEM and why is it appropriate to include these costs in your analysis?

A. The Company estimated in its study that, in 2015, a cost of $12,607 was related to answering inquiries from residential customers who were interested in details of the NEM program. The Company included these costs in its analysis because these inquiries are directly related to the existence of the NEM program.

Q. Mr. Stanley argues that "(t)he Company never details or accounts for how the hours allegedly incurred were allocated and who performed the actual work, e.g., if it was an engineer or a staff. Most initial applications are reviewed by administrative personnel who do not require an engineer's salary. The Company has not shown that the costs were necessary."[79] Please comment.

A. It is unclear why Mr. Stanley claims that the Company did not differentiate between work performed by an engineer as compared to other staff. My exhibits Exhibit RMP___(RMM-6), Exhibit RMP___(RMM-7), and Exhibit RMP___(RMM-8) show the Company's estimates of work performed by customer services, customer generation

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[77] *Id.* at ll. 136-45.
[78] Exhibit RMP___(RMM-6); Robert M. Meredith, Direct Testimony, ll. 297-98.
[79] Stanley Direct Testimony, ll. 146-51.

administration, and engineering personnel, respectively. Mr. Stanley provides no basis for his claim that "(m)ost initial applications are reviewed by administrative personnel who do not require an engineer's salary."

Rebuttal of HEAL Utah witness Jeremy Fisher

Q. Mr. Fisher argues that the Company's coal fleet would not satisfy the cost of service framework imposed upon the NEM program.[80] Does his comparison demonstrate that the cost and benefit framework required by the November 2015 Order is unreasonable?

A. Not at all. While I did not verify the calculations Mr. Fisher presents, the premise of his argument is faulty and therefore requires no further inquiry. Mr. Fisher's comparison of retail rates to the costs of the Company's coal fleet has no direct relevance to the costs and benefits of private generation because they are very different types of generation. The Company's fleet of coal-fired generators is cost effectively dispatched to serve customer load and provide operational flexibility necessary to meet the Company's reliability obligations. Rooftop solar is non-dispatchable and does not have these same capabilities. Investments have been made to keep the Company's thermal fleet in service in order to reliably serve all customers at a low operating cost. Those investments have been subject to regulatory scrutiny and have been approved under applicable standards imposed by Utah law and Commission orders. The Company's coal fleet is required to serve the Company's retail loads. In contrast, rooftop solar systems are not needed to meet the Company's load nor do they have the ability to do so. Because the Company's coal fleet is entirely different from rooftop

[80] Fisher Direct Testimony, pp. 19-29.

solar systems, the “all-in” fixed and variable costs of the Company’s coal generators as opposed to the cost of bill credits paid for private generation are not remotely similar and cannot be compared on an apples-to-apples basis as Mr. Fisher attempts to do. For that reason, Mr. Fisher’s comparison is a false comparison and is irrelevant to this proceeding.

Response to DPU witness Stan Faryniarz

Q. Mr. Faryniarz describes a potential error in the difference in cost of meters used for NEM and non-NEM customers on Schedule 23.[81] Did the Company incorrectly determine these costs?

A. Yes. The Company inadvertently used the cost of a meter used for residential NEM customers for Schedule 23 NEM customers. The NEM Breakout COS model has been modified to correct this. After further examining the estimated meter costs for net metering customers on other non-residential rate schedules, I also noted that the meter costs for smaller-sized NEM customers on Schedule 6 and Schedule 10 were not updated to reflect the particular costs of a meter used to serve NEM customers. This has also been corrected in the NEM Breakout COS I present in this rebuttal testimony.

Updates to the Cost of Service Analyses

Q. Please identify all updates to the Company’s cost of service analyses.

A. The Company identified the following corrections for its cost of service-related analyses:

- On the ‘Func Factors’ tab of the ACOS and the NEM Breakout COS study, the PT and PTD functional factors were not updated to be based upon normalized

[81] DPU witness Mr. Stan Faryniarz’s Direct Testimony, ll. 1224-1241.

values in the JAM instead of actuals.[82]

- On the NEM Breakout COS study, factors F47 and F48 were modified for the irrigation and irrigation NEM classes to be based upon average bills instead of annual customers consistent with other cost of service models.

Along with these corrections, the Company also agrees with Vivint Solar witness Mr. Collins[83] to modify the CFCOS so that it includes additional VOM costs associated with increased thermal generation. The Company has also modified its integration costs to a lower more recent estimate. Company witness Mr. Wilding discusses the calculation of incremental VOM and revised integration costs for the CFCOS analysis. The incremental benefit of reduced VOM and lower integration costs reduces the net cost of the net metering program at the system level by about $0.15 million, or by about $2.83 per megawatt hour. The NEM Breakout COS was also modified to reflect the higher value for exported energy.

Responsive to the testimonies of EFCA witness Mr. Gilfenbaum and DPU witness Mr. Faryniarz, the Company also agrees to modify its NEM Breakout COS study so that the allocation of distribution line transformers for the residential net metering class is based upon the non-coincident peak in the month of July. Finally, the Company modified the cost of meters for smaller non-residential net metering customers. I described this change in more detail in my response to Mr. Faryniarz's direct testimony.

[82] See the Company's response to OCS Data Request 6.8 provided in Exhibit RMP___(RMM-8R).
[83] Collins Direct Testimony, ll. 498-504.

Q. After making these changes, what are the results of the Company's analyses?

A. Exhibit RMP___(RMM-2R) shows revised costs and benefits of the net metering program at the system, state, and class levels as required by the November 2015 Order in the same format as I presented them in Exhibit RMP___(RMM-1) of my direct testimony. The comparison of the CFCOS to the ACOS continues to show a net cost for the net metering program. The revised net cost is $3.6 million at the system level, $2.0 million at the state level, and $1.6 million for residential customers. This compares to the net cost values of $3.7 million at the system level, $2.0 million at the state level, and $1.7 million for residential customers that I presented in my direct testimony.

Exhibit RMP___(RMM-3R) shows summary of revised results from the ACOS study, the CFCOS study, and the difference between the two studies in the same format as I presented them in Exhibit RMP___(RMM-2) of my direct testimony.

Exhibit RMP___(RMM-4R) shows the revised value of excess energy credits used in the NEM Breakout COS in the same format as I presented them in Exhibit RMP___(RMM-11) of my direct testimony.

Exhibit RMP___(RMM-5R) shows the revised results of the NEM Breakout COS study in the same format as I presented them in Exhibit RMP___(RMM-12) of my direct testimony. After making the changes that I described earlier in this testimony, the NEM Breakout COS shows that the residential net metering class continues to require a substantial increase in revenue to be at full cost of service. Exhibit RMP___(RMM-5R) shows that residential net metering customers require a 55.99 percent increase to present revenues which compares to a 65.05 percent increase that I presented in my direct testimony.

Exhibit RMP___(RMM-6R) shows the revised difference in cost of service results for each class between the NEM Breakout COS and the ACOS in the same format as I presented them in Exhibit RMP___(RMM-13) of my direct testimony.

Exhibit RMP___(RMM-7R) shows the same adjustment I made in Exhibit RMP___(RMM-14) to bring the NEM Breakout COS results for the residential net metering class to the level of costs from the 2014 General Rate Case for the revised study.

Conclusion

Q. Please summarize your rebuttal testimony.

A. In response to the direct testimonies of other witnesses, the Company has made three adjustments to its analyses:

- First in the CFCOS, the benefit of reduced generation VOM and lower integration cost is now reflected;
- Second, the allocation of distribution line transformers in the NEM Breakout COS is now based upon non-coincident peak in July for the residential net metering class; and
- Third, the cost of meters for small non-residential net metering customers has been corrected.

In addition to these three modifications, two other minor corrections were made to the Company's studies.

The Company's CFCOS compared to ACOS analysis continues to support a determination from the Commission that costs are greater than benefits for the NEM program. Attempts by other parties to seek an alteration of the framework that the

Commission ordered in its November 2015 Order are not supported by any new evidence or argument, nor do they justify the different approaches they advocate for that would either ignore the realities of the costs imposed by the NEM program on non-participating customers or seek to include speculative future benefits.

Q. What is your recommendation for the Commission?

A. The Company recommends that the Commission issue an order finding that the results of both of the analyses that I presented as modified in this testimony are accurate, reliable and are consistent with the November 2015 Order.

Q. Does this conclude your rebuttal testimony?

A. Yes.

Rocky Mountain Power
Exhibit RMP___(RMM-1R)
Docket No. 14-035-114
Witness: Robert M. Meredith

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

Exhibit Accompanying Rebuttal Testimony of Robert M. Meredith

Peak Reduction from Private Generation

July 2017

Rocky Mountain Power
State of Utah
12 Months Ending December 31, 2015
Capacity Contribution of Private Generation
12 System Coincident Peaks

	Nameplate Capacity (MW)	CFJAM System Peak (MW)	AJAM System Peak (MW)	Difference in System Peak (MW)	Capacity Contribution
January	28.7	8,343	8,343	0.0	0%
February	30.0	8,531	8,527	4.1	14%
March	31.9	7,927	7,924	2.5	8%
April	33.1	7,411	7,411	0.5	1%
May	34.7	7,360	7,350	9.7	28%
June	36.6	9,467	9,450	17.3	47%
July	38.7	10,389	10,363	26.1	68%
August	40.5	9,322	9,305	16.7	41%
September	43.7	8,312	8,289	23.9	55%
October	48.1	7,352	7,339	13.0	27%
November	52.1	8,267	8,267	0.0	0%
December	56.0	8,325	8,325	0.0	0%

Average Capacity Contribution 24%

Rocky Mountain Power
Exhibit RMP___(RMM-2R)
Docket No. 14-035-114
Witness: Robert M. Meredith

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

Exhibit Accompanying Rebuttal Testimony of Robert M. Meredith

Updated Costs and Benefits of the Net Metering Program

July 2017

Rocky Mountain Power
State of Utah
12 Months Ended Dec 2015
Costs and Benefits of the Net Metering Program at the PacifiCorp System Level

		Unit	System
Costs	Increased Metering Cost	$000	$161
	Increased Engineering/Administration	$000	$528
	Increased Customer Service/Billing Cost	$000	$83
	Bill Credits	$000	$4,237
	Total Cost	$000	$5,010
Benefits	Lower Net Power Costs	$000	($1,304)
	Lower Line Losses	$000	($133)
	Total Benefit	$000	($1,437)
	Net Cost /(Benefit)	$000	$3,573
	Net Metering Energy Production	MWh	52,877
	Net Cost /(Benefit)	$/MWh	$67.57

Rocky Mountain Power
State of Utah
12 Months Ended Dec 2015
Costs and Benefits of the Net Metering Program at the State of Utah Jurisdictional Level

		Unit	State
Costs	Increased Metering Cost	$000	$161
	Increased Engineering/Administration	$000	$528
	Increased Customer Service/Billing Cost	$000	$83
	Bill Credits	$000	$4,237
	Total Cost	$000	$5,010
Benefits	Lower Net Power Costs	$000	($1,304)
	Lower Interjurisdictional Allocation	$000	($1,588)
	Lower Line Losses	$000	($133)
	Total Benefit	$000	($3,025)
	Net Cost /(Benefit)	$000	$1,985
	Net Metering Energy Production	MWh	52,877
	Net Cost /(Benefit)	$/MWh	$37.53

Rocky Mountain Power
State of Utah
12 Months Ended Dec 2015
Costs and Benefits of the Net Metering Program at the Customer Class Level

		Unit	Residential	Schedule 23	Schedule 6	Schedule 8	Schedule 10	Other Classes	Total
Costs	Increased Metering Cost	$000	$112	$19	$17	$2	$2	$8	$161
	Increased Engineering/Administration	$000	$369	$48	$76	$17	$4	$13	$528
	Increased Customer Service/Billing Cost	$000	$72	$8	$2	$0	$0	$1	$83
	Bill Credits	$000	$2,987	$429	$578	$221	$22	($0)	$4,237
	Total Cost	$000	$3,540	$504	$673	$240	$29	$22	$5,009
Benefits	Lower Net Power Costs	$000	$737	$147	$352	$158	$12	($102)	$1,304
	Lower Class Allocation	$000	($2,713)	($570)	($1,056)	($575)	($35)	$488	($4,462)
	Lower Line Losses	$000	$75	$15	$36	$16	$1	($10)	$132
	Total Benefit	$000	($1,900)	($409)	($668)	($401)	($22)	$375	($3,026)
	Net Cost /(Benefit)	$000	$1,640	$96	$5	($160)	$7	$397	$1,985
	Net Metering Energy Production	MWh	28,304	6,012	12,342	5,736	484	N/A	52,877
	Net Cost /(Benefit)	$/MWh	$57.94	$15.95	$0.42	($27.97)	$14.07	N/A	$37.53
	Net Metering Customer Count	#	4,390	327	194	8	13	N/A	4,931
	Total Customer Count	#	754,063	84,785	15,598	250	3,354	12,543	870,593
	Net Metering Customers as a Proportion of Total	%	0.58%	0.39%	1.24%	3.07%	0.39%	N/A	0.57%

Net Cost /(Benefit) per Net Metering Customer							
$/Customer/Year	$373.53	$293.53	$26.72	($20,929)	$524.84	N/A	$402.50

This summary shows that the net cost of the net metering program for the residential class in 2015 was $1.6 million, or $57.94 per MWh of net metering energy production. This results in an annual net cost of $373.53 per residential net metering customer.

Rocky Mountain Power
Exhibit RMP___(RMM-3R)
Docket No. 14-035-114
Witness: Robert M. Meredith

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

Exhibit Accompanying Rebuttal Testimony of Robert M. Meredith

Updated Summary of Results for ACOS and CFCOS

July 2017

Rocky Mountain Power
Actual Cost Of Service By Rate Schedule
State of Utah
12 Months Ended Dec 2015
2010 Protocol (Non Wgt)
7.56% = Earned Return on Rate Base

	A	B	C	D	E	F	G	H	I	J	K	L	M
Line No.	Schedule No.	Description	Annual Revenue	Return on Rate Base	Rate of Return Index	Total Cost of Service	Production Cost of Service	Transmission Cost of Service	Distribution Cost of Service	Retail Cost of Service	Misc Cost of Service	Increase (Decrease) to = ROR	Percentage Change from Current Revenues
1	1	Residential	722,768,968	6.84%	0.90	753,155,918	436,454,928	102,396,865	180,740,302	30,142,586	3,421,236	30,386,950	4.20%
2	6	General Service - Large	533,598,118	9.03%	1.19	495,603,006	348,871,728	74,984,615	68,062,374	1,544,361	2,139,928	(37,995,112)	-7.12%
3	8	General Service - Over 1 MW	154,416,644	8.37%	1.11	148,399,344	108,149,238	22,368,216	17,254,832	5,751	621,306	(6,017,300)	-3.90%
4	7,11,12	Street & Area Lighting	11,464,577	13.48%	1.78	9,190,918	3,432,575	536,050	4,927,771	258,269	36,254	(2,273,660)	-19.83%
5	9	General Service - High Voltage	274,856,221	6.24%	0.82	292,431,156	241,713,111	49,339,136	189,331	44,263	1,145,314	17,574,935	6.39%
6	10	Irrigation	17,790,044	6.70%	0.89	18,666,272	12,283,733	2,525,226	3,779,337	(3,963)	81,940	876,229	4.93%
7	15	Traffic Signals	749,867	10.69%	1.41	653,975	347,929	65,792	156,910	80,803	2,542	(95,892)	-12.79%
8	15	Outdoor Lighting	1,299,357	16.87%	2.23	933,981	724,205	108,640	80,418	17,456	3,262	(365,376)	-28.12%
9	23	General Service - Small	136,301,217	8.89%	1.18	127,157,603	80,394,947	17,627,594	27,429,274	1,131,619	574,169	(9,143,614)	-6.71%
10	SpC	Customer 1	27,835,175	3.59%	0.48	34,000,294	27,943,550	5,758,436	81,427	83,894	132,987	6,165,119	22.15%
11	SpC	Customer 2	43,083,978	7.07%	0.93	43,971,699	37,149,534	6,475,718	99,245	95,355	151,846	887,721	2.06%
12		Total Utah Jurisdiction	1,924,164,165	7.56%	1.00	1,924,164,165	1,297,465,479	282,186,287	302,801,222	33,400,394	8,310,784	(0)	0.00%

Footnotes :

Column C : Annual revenues based on January 2015 thru December 2015 data.
Column D : Calculated Return on Ratebase per January 2015 thru December 2015 Embedded Cost of Service Study
Column E : Rate of Return Index. Rate of return by rate schedule, divided by Utah Jurisdiction's normalized rate of return.
Column F : Calculated Full Cost of Service at Jurisdictional Rate of Return per the January 2015 thru December 2015 Embedded COS Study
Column G : Calculated Generation Cost of Service at Jurisdictional Rate of Return per the January 2015 thru December 2015 Embedded COS Study.
Column H : Calculated Transmission Cost of Service at Jurisdictional Rate of Return per the January 2015 thru December 2015 Embedded COS Study.
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Column K : Calculated Miscellaneous Cost of Service at Jurisdictional Rate of Return per the January 2015 thru December 2015 Embedded COS Study.
Column L : Increase or Decrease Required to Move From Annual Revenue to Full Cost of Service Dollars.
Column M : Increase or Decrease Required to Move From Annual Revenue to Full Cost of Service Percent.

Rocky Mountain Power
Counterfactual Cost Of Service By Rate Schedule
State of Utah
12 Months Ended Dec 2015
2010 Protocol (Non Wgt)
7.56% = Target Return on Rate Base

	A	B	C	D	E	F	G	H	I	J	K	L	M
Line No.	Schedule No.	Description	Annual Revenue	Return on Rate Base	Rate of Return Index	Total Cost of Service	Production Cost of Service	Transmission Cost of Service	Distribution Cost of Service	Retail Cost of Service	Misc Cost of Service	Increase (Decrease) to = ROR	Percentage Change from Current Revenues
1	1	Residential	725,755,615	6.88%	0.91	754,481,003	437,964,360	102,692,781	180,516,950	29,882,845	3,424,067	28,725,388	3.96%
2	6	General Service - Large	534,176,006	9.03%	1.19	496,179,751	349,504,529	75,090,251	67,908,066	1,537,546	2,139,359	(37,996,255)	-7.11%
3	8	General Service - Over 1 MW	154,637,763	8.35%	1.10	148,783,057	108,462,106	22,427,663	17,264,616	6,601	622,071	(5,854,706)	-3.79%
4	7,11,12	Street & Area Lighting	11,464,578	14.33%	1.89	8,916,788	3,198,397	511,451	4,916,378	254,936	35,626	(2,547,790)	-22.22%
5	9	General Service - High Voltage	274,856,220	6.24%	0.82	292,344,562	241,668,588	49,306,212	183,300	43,383	1,143,078	17,488,342	6.36%
6	10	Irrigation	17,812,538	6.70%	0.88	18,681,584	12,306,873	2,529,488	3,767,905	(4,586)	81,904	869,046	4.88%
7	15	Traffic Signals	749,866	10.74%	1.42	652,357	347,862	65,737	156,243	79,980	2,535	(97,509)	-13.00%
8	15	Outdoor Lighting	1,299,358	16.89%	2.23	933,544	724,239	108,569	80,202	17,279	3,256	(365,814)	-28.15%
9	23	General Service - Small	136,730,488	8.90%	1.17	127,488,420	80,706,078	17,691,251	27,410,065	1,105,982	575,045	(9,242,068)	-6.76%
10	SpC	Customer 1	27,835,175	3.60%	0.47	33,989,993	27,938,024	5,754,575	80,976	83,692	132,727	6,154,818	22.11%
11	SpC	Customer 2	43,083,978	7.07%	0.93	43,965,818	37,148,487	6,471,848	98,789	95,134	151,560	881,840	2.05%
12		Total Utah Jurisdiction	1,928,401,585	7.58%	1.00	1,926,416,877	1,299,969,542	282,649,827	302,383,489	33,102,792	8,311,227	(1,984,708)	-0.10%

Footnotes :

Column C : Annual revenues based on January 2015 thru December 2015 data.
Column D : Calculated Return on Ratebase per January 2015 thru December 2015 Embedded Cost of Service Study
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Rocky Mountain Power
Counterfactual Cost Of Service less Actual Cost of Service By Rate Schedule
State of Utah
12 Months Ended Dec 2015
2010 Protocol (Non Wgt)
7.56% = Target Return on Rate Base

	A	B	C	D	E	F	G	H	I	J	K	L	M
Line No.	Schedule No.	Description	Annual Revenue	Return on Rate Base	Rate of Return Index	Total Cost of Service	Production Cost of Service	Transmission Cost of Service	Distribution Cost of Service	Retail Cost of Service	Misc Cost of Service	Increase (Decrease) to = ROR	Percentage Change from Current Revenues
1	1	Residential	2,986,647	0.04%	0.00	1,325,085	1,509,431	295,916	(223,353)	(259,741)	2,831	(1,661,562)	-0.25%
2	6	General Service - Large	577,888	0.00%	(0.00)	576,745	632,801	105,636	(154,308)	(6,815)	(570)	(1,143)	0.01%
3	8	General Service - Over 1 MW	221,119	-0.02%	(0.01)	383,713	312,868	59,447	9,784	849	765	162,595	0.11%
4	7,11,12	Street & Area Lighting	1	0.84%	0.11	(274,130)	(234,177)	(24,598)	(11,393)	(3,333)	(629)	(274,130)	-2.39%
5	9	General Service - High Voltage	(1)	0.01%	(0.00)	(86,594)	(44,523)	(32,924)	(6,031)	(880)	(2,236)	(86,593)	-0.03%
6	10	Irrigation	22,494	0.01%	(0.00)	15,311	23,139	4,263	(11,432)	(623)	(36)	(7,183)	-0.05%
7	15	Traffic Signals	(1)	0.06%	0.00	(1,618)	(67)	(55)	(667)	(822)	(7)	(1,617)	-0.22%
8	15	Outdoor Lighting	1	0.02%	(0.00)	(437)	33	(71)	(216)	(177)	(6)	(438)	-0.03%
9	23	General Service - Small	429,271	0.01%	(0.00)	330,816	311,131	63,657	(19,210)	(25,637)	876	(98,455)	-0.05%
10	SpC	Customer 1	0	0.00%	(0.00)	(10,300)	(5,526)	(3,861)	(451)	(202)	(260)	(10,300)	-0.04%
11	SpC	Customer 2	0	0.00%	(0.00)	(5,881)	(1,047)	(3,871)	(456)	(222)	(286)	(5,881)	-0.01%
12		Total Utah Jurisdiction	4,237,420	0.02%	0.00	2,252,712	2,504,063	463,540	(417,733)	(297,602)	443	(1,984,708)	-0.10%

Footnotes :

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Rocky Mountain Power
Exhibit RMP___(RMM-4R)
Docket No. 14-035-114
Witness: Robert M. Meredith

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

Exhibit Accompanying Rebuttal Testimony of Robert M. Meredith

Updated Value of Excess NEM Credits

July 2017

PacifiCorp
Cost Of Service By Rate Schedule
State of Utah
2010 Protocol (Non Wgt)
12 Months Ended December 2015
Value of Excess NEM Credits

	Jan-15	Feb-15	Mar-15	Apr-15	May-15	Jun-15	Jul-15	Aug-15	Sep-15	Oct-15	Nov-15	Dec-15	Total
Residential-NEM - Schedule 1-135													
Exported Energy (MWh)	303	602	1,196	1,539	1,427	2,051	1,521	1,734	1,275	1,653	1,621	1,040	15,961
Net Power Cost ($/MWh)	$22.04	$20.15	$21.41	$20.09	$20.49	$27.36	$33.62	$34.96	$23.76	$21.87	$20.29	$18.69	
Line Losses ($/MWh)	$2.05	$1.87	$1.99	$1.86	$1.90	$2.54	$3.12	$3.24	$2.20	$2.03	$1.88	$1.73	
Energy Value from Exported Energy ($)	$7,301.17	$13,249.62	$27,990.37	$33,771.95	$31,942.97	$61,306.12	$55,868.92	$66,253.48	$33,098.78	$39,494.25	$35,940.99	$21,250.95	$427,469.54
Average Energy Value from Exported Energy ($)													$26.78
NEM Credits from Banking (MWh)	207	(19)	(115)	(419)	(428)	(204)	(7)	(155)	(63)	(197)	78	573	(749)
Energy Value from NEM Credits from Banking ($)													-$20,050.39
Energy Value from Excess NEM Credits ($)													$407,419.15
General Service - Large-NEM - Schedule 6-135													
Exported Energy (MWh)	130	197	349	512	569	517	597	538	431	451	389	329	5,007
Net Power Cost ($/MWh)	$22.04	$20.15	$21.41	$20.09	$20.49	$27.36	$33.62	$34.96	$23.76	$21.87	$20.29	$18.69	
Line Losses ($/MWh)	$2.05	$1.87	$1.99	$1.86	$1.90	$2.54	$3.12	$3.24	$2.20	$2.03	$1.88	$1.73	
Energy Value from Exported Energy ($)	$3,123.23	$4,348.81	$8,163.09	$11,230.19	$12,731.67	$15,453.07	$21,927.84	$20,532.68	$11,187.44	$10,781.61	$8,630.77	$6,712.29	$134,822.70
Average Energy Value from Exported Energy ($)													$26.92
NEM Credits from Banking (MWh)	254	108	9	(72)	(52)	(166)	(32)	(71)	(76)	(9)	35	100	30
Energy Value from NEM Credits from Banking ($)													$794.50
Energy Value from Excess NEM Credits ($)													$135,617.20
General Service - Over 1 MW-NEM - Schedule 8-135													
Exported Energy (MWh)	-	1	9	49	42	53	16	0	0	2	1	1	175
Net Power Cost ($/MWh)	$22.04	$20.15	$21.41	$20.09	$20.49	$27.36	$33.62	$34.96	$23.76	$21.87	$20.29	$18.69	
Line Losses ($/MWh)	$2.05	$1.87	$1.99	$1.86	$1.90	$2.54	$3.12	$3.24	$2.20	$2.03	$1.88	$1.73	
Energy Value from Exported Energy ($)	$0.00	$32.41	$213.12	$1,071.05	$936.96	$1,592.84	$570.38	$6.48	$3.81	$45.55	$32.62	$23.51	$4,528.74
Average Energy Value from Exported Energy ($)													$25.90
NEM Credits from Banking (MWh)	4	10	(1)	(0)	6	(35)	15	4	(14)	(15)	(3)	(0)	(29)
Energy Value from NEM Credits from Banking ($)													-$745.09
Energy Value from Excess NEM Credits ($)													$3,783.65
Irrigation-NEM - Schedule 10-135													
Exported Energy (MWh)	0	0	0	0	137	22	32	22	27	30	40	0	309
Net Power Cost ($/MWh)	$22.04	$20.15	$21.41	$20.09	$20.49	$27.36	$33.62	$34.96	$23.76	$21.87	$20.29	$18.69	
Line Losses ($/MWh)	$2.05	$1.87	$1.99	$1.86	$1.90	$2.54	$3.12	$3.24	$2.20	$2.03	$1.88	$1.73	
Energy Value from Exported Energy ($)	$0.00	$0.00	$0.00	$0.00	$3,074.77	$655.27	$1,166.50	$822.49	$694.55	$717.28	$877.01	$0.00	$8,007.86
Average Energy Value from Exported Energy ($)													$25.93
NEM Credits from Banking (MWh)	(0)	(0)	(0)	(0)	6	(27)	11	16	(20)	(46)	(40)	(0)	(100)
Energy Value from NEM Credits from Banking ($)													-$2,586.85
Energy Value from Excess NEM Credits ($)													$5,421.02

PacifiCorp
Cost Of Service By Rate Schedule
State of Utah
2010 Protocol (Non Wgt)
12 Months Ended December 2015
Value of Excess NEM Credits

	Jan-15	Feb-15	Mar-15	Apr-15	May-15	Jun-15	Jul-15	Aug-15	Sep-15	Oct-15	Nov-15	Dec-15	Total
General Service - Small - NEM - Schedule 23-135													
Exported Energy (MWh)	99	175	249	373	354	260	353	371	268	271	267	175	3,216
Net Power Cost ($/MWh)	$22.04	$20.15	$21.41	$20.09	$20.49	$27.36	$33.62	$34.96	$23.76	$21.87	$20.29	$18.69	
Line Losses ($/MWh)	$2.05	$1.87	$1.99	$1.86	$1.90	$2.54	$3.12	$3.24	$2.20	$2.03	$1.88	$1.73	
Energy Value from Exported Energy ($)	$2,390.92	$3,848.30	$5,828.77	$8,190.69	$7,924.44	$7,776.37	$12,980.49	$14,165.01	$6,969.90	$6,473.44	$5,926.42	$3,568.28	$86,043.02
Average Energy Value from Exported Energy ($)													$26.76
NEM Credits from Banking (MWh)	53	0	(63)	(123)	(115)	(183)	(83)	(90)	(106)	(77)	(33)	87	(733)
Energy Value from NEM Credits from Banking ($)													-$19,613.00
Energy Value from Excess NEM Credits ($)													$66,430.02
Total													
Exported Energy (MWh)	532	975	1,803	2,472	2,529	2,903	2,518	2,664	2,001	2,407	2,319	1,545	24,668
Net Power Cost ($/MWh)	$22.04	$20.15	$21.41	$20.09	$20.49	$27.36	$33.62	$34.96	$23.76	$21.87	$20.29	$18.69	
Line Losses ($/MWh)	$2.05	$1.87	$1.99	$1.86	$1.90	$2.54	$3.12	$3.24	$2.20	$2.03	$1.88	$1.73	
Energy Value from Exported Energy ($)	$12,815.31	$21,479.14	$42,195.35	$54,263.89	$56,610.80	$86,783.68	$92,514.13	$101,780.14	$51,954.48	$57,512.12	$51,407.80	$31,555.03	$660,871.87
Average Energy Value from Exported Energy ($)													$26.70
NEM Credits from Banking (MWh)	518	99	(169)	(615)	(583)	(614)	(95)	(297)	(280)	(344)	38	760	(1,581)
Energy Value from NEM Credits from Banking ($)													-$42,200.83
Energy Value from Excess NEM Credits ($)													$618,671.04

Net Metering Production MWh @ sales	52,877
Net Metering Production MWh @ input	57,784
Net Metering Production Loss Factor	9.28%

Rocky Mountain Power
Exhibit RMP___(RMM-5R)
Docket No. 14-035-114
Witness: Robert M. Meredith

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

Exhibit Accompanying Rebuttal Testimony of Robert M. Meredith

Updated Summary of Results for NEM Breakout COS

July 2017

Rocky Mountain Power
Cost Of Service By Rate Schedule
State of Utah
12 Months Ended Dec 2015
2010 Protocol (Non Wgt)
7.56% = Earned Return on Rate Base

	A	B	C	D	E	F	G	H	I	J	K	L	M
Line No.	Schedule No.	Description	Annual Revenue	Return on Rate Base	Rate of Return Index	Total Cost of Service	Production Cost of Service	Transmission Cost of Service	Distribution Cost of Service	Retail Cost of Service	Misc Cost of Service	Increase (Decrease) to = ROR	Percentage Change from Current Revenues
1	1	Residential	719,990,943	6.85%	0.91	749,481,026	434,774,861	101,969,664	179,610,635	29,720,071	3,405,796	29,490,083	4.10%
2	1-135	Residential-NEM	2,778,025	0.85%	0.11	4,333,411	2,054,837	559,425	1,270,588	429,601	18,960	1,555,386	55.99%
3	6	General Service - Large	525,707,898	9.04%	1.20	488,057,073	343,656,807	73,835,794	66,942,652	1,514,751	2,107,068	(37,650,826)	-7.16%
4	6-135	General Service - Large-NEM	7,890,216	9.35%	1.24	7,211,481	4,996,958	1,099,043	1,045,033	38,993	31,453	(678,735)	-8.60%
5	8	General Service - Over 1 MW	149,029,192	8.36%	1.11	143,265,630	104,345,151	21,571,302	16,634,384	115,629	599,164	(5,763,562)	-3.87%
6	8-135	General Service - Over 1 MW-NEM	5,387,429	9.40%	1.24	4,940,508	3,680,171	747,730	602,695	(111,042)	20,954	(446,921)	-8.30%
7	7,11,12	Street & Area Lighting	11,464,575	13.52%	1.79	9,178,926	3,432,419	535,688	4,919,173	255,401	36,245	(2,285,649)	-19.94%
8	9	General Service - High Voltage	274,856,221	6.24%	0.83	292,358,600	241,675,888	49,310,532	183,882	43,671	1,144,627	17,502,379	6.37%
9	10	Irrigation	17,679,271	6.70%	0.89	18,549,373	12,213,548	2,510,010	3,748,569	(4,174)	81,421	870,102	4.92%
10	10-135	Irrigation-NEM	110,799	5.63%	0.74	122,317	69,738	14,552	32,965	4,583	480	11,518	10.40%
11	15	Traffic Signals	749,867	10.73%	1.42	652,631	347,870	65,747	156,479	79,995	2,539	(97,236)	-12.97%
12	15	Outdoor Lighting	1,299,357	16.89%	2.23	933,564	724,164	108,564	80,291	17,284	3,260	(365,793)	-28.15%
13	23	General Service - Small	135,802,412	8.91%	1.18	126,588,250	80,101,486	17,556,669	27,258,246	1,100,177	571,672	(9,214,162)	-6.78%
14	23-135	General Service - Small - NEM	498,803	6.35%	0.84	535,413	305,817	74,593	136,167	16,350	2,485	36,610	7.34%
15	SpC	Customer 1	27,835,175	3.60%	0.48	33,992,017	27,939,109	5,755,113	81,044	83,843	132,908	6,156,842	22.12%
16	SpC	Customer 2	43,083,978	7.07%	0.94	43,963,941	37,146,338	6,471,711	98,848	95,294	151,750	879,963	2.04%
17		Total Utah Jurisdiction	1,924,164,161	7.56%	1.00	1,924,164,161	1,297,465,161	282,186,136	302,801,652	33,400,428	8,310,784	0	0.00%

Footnotes :

Column C : Annual revenues based on January 2015 thru December 2015 data.
Column D : Calculated Return on Ratebase per January 2015 thru December 2015 Embedded Cost of Service Study
Column E : Rate of Return Index. Rate of return by rate schedule, divided by Utah Jurisdiction's normalized rate of return.
Column F : Calculated Full Cost of Service at Jurisdictional Rate of Return per the January 2015 thru December 2015 Embedded COS Study
Column G : Calculated Generation Cost of Service at Jurisdictional Rate of Return per the January 2015 thru December 2015 Embedded COS Study.
Column H : Calculated Transmission Cost of Service at Jurisdictional Rate of Return per the January 2015 thru December 2015 Embedded COS Study.
Column I : Calculated Distribution Cost of Service at Jurisdictional Rate of Return per the January 2015 thru December 2015 Embedded COS Study.
Column J : Calculated Retail Cost of Service at Jurisdictional Rate of Return per the January 2015 thru December 2015 Embedded COS Study.
Column K : Calculated Miscellaneous Cost of Service at Jurisdictional Rate of Return per the January 2015 thru December 2015 Embedded COS Study.
Column L : Increase or Decrease Required to Move From Annual Revenue to Full Cost of Service Dollars.
Column M : Increase or Decrease Required to Move From Annual Revenue to Full Cost of Service Percent.

Rocky Mountain Power
Exhibit RMP___(RMM-6R)
Docket No. 14-035-114
Witness: Robert M. Meredith

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

Exhibit Accompanying Rebuttal Testimony of Robert M. Meredith

Updated NEM Breakout COS Compared to ACOS

July 2017

Rocky Mountain Power
NEM Breakout Cost Of Service Compared to Actual Cost of Service
State of Utah
12 Months Ended Dec 2015
2010 Protocol (Non Wgt)

	A	B	C	D	E
Line No.	Schedule No.	Description	ACOS Increase (Decrease) to = ROR	NEM Breakout Increase (Decrease) to = ROR	NEM Breakout less ACOS Increase (Decrease) to = ROR
1	1	Residential	30,386,950	29,490,083	(896,867)
2	1-135	Residential-NEM		1,555,386	
3	6	General Service - Large	(37,995,112)	(37,650,826)	344,286
4	6-135	General Service - Large-NEM		(678,735)	
5	8	General Service - Over 1 MW	(6,017,300)	(5,763,562)	253,738
6	8-135	General Service - Over 1 MW-NEM		(446,921)	
7	10	Irrigation	876,229	870,102	(6,127)
8	10-135	Irrigation-NEM		11,518	
9	23	General Service - Small	(9,143,614)	(9,214,162)	(70,549)
10	23-135	General Service - Small - NEM		36,610	

Rocky Mountain Power
Exhibit RMP___(RMM-7R)
Docket No. 14-035-114
Witness: Robert M. Meredith

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

Exhibit Accompanying Rebuttal Testimony of Robert M. Meredith

Updated Determination of Residential NEM COS at the Same Basis as Rates Set in Docket No. 13-084-184

July 2017

Rocky Mountain Power
State of Utah
Determination of Residential Net Metering Cost of Service
At the Same Basis as Rates Set in Docket No. 13-084-184

Row	Description	Docket No. 13-035-184 Residential Sch 1 @ Step 2 Revenue (A)	Actual 2015 Cost of Service Study With Net Metering Broken Out Sch 1 Non-Net Metering (B)	Actual 2015 Cost of Service Study With Net Metering Broken Out Sch 1 Net Metering (C)	Actual 2015 Cost of Service Study With Net Metering Broken Out Net Metering as a Percentage of Overall Residential (D) (C) / [(B) + (C)]	Sch 1 Net Metering @ GRC Level (E)	Calculation (F)
16	**UNITS**						
17	NCP kW	57,008,525	56,098,384	387,862		387,862	
18	Annual KWH	6,203,851,850	6,523,256,321	39,124,078		39,124,078	
19	Average Customers	740,636	749,673	4,390		4,390	
20	Load Factor	15%	16%	14%		15%	
21			63%				
22							
23	**PTDRM TOTAL**	37.04%	38.95%	0.23%			
24	Revenue Requirement	684,856,226	749,481,026	4,333,411		$\boxed{3,980,120}$	30 + 48 + 66 + 102 + 108
25	Per NCP kW	12.01	13.36	11.17		10.26	24 / 17
26	Per KWH	0.110	0.115	0.111		0.102	24 / 18
27	Per Customer	924.69	999.74	987.11		906.63	24 / 19
28							
29	**PRODUCTION-TOTAL**	31.04%	33.51%	0.16%			
30	Revenue Requirement	378,607,813	434,774,861	2,054,837		1,749,480	36 + 42
31	Per NCP kW	6.64	7.75	5.30		4.51	30 / 17
32	Per KWH	0.061	0.067	0.053		0.045	30 / 18
33	Per Customer	511.19	579.95	468.07		398.51	30 / 19
34							
35	**PRODUCTION-DEMAND**	34.99%	38.33%	0.21%			
36	Revenue Requirement	186,193,456	239,501,335	1,283,858	0.533%	992,777	(D) * (A)
37	Per NCP kW	3.27	4.27	3.31		-	36 / 17
38	Per KWH	0.030	0.037	0.033		0.025	36 / 18
39	Per Customer	251.40	319.47	292.45		226.15	36 / 19
40							
41	**PRODUCTION-ENERGY**	27.99%	29.03%	0.11%			
42	Revenue Requirement	192,414,357	195,273,525	770,979	0.393%	756,703	(D) * (A)
43	Per NCP kW	3.38	3.48	1.99		1.95	42 / 17
44	Per KWH	0.031	0.030	0.020		0.019	42 / 18
45	Per Customer	259.80	260.48	175.62		172.37	42 / 19
46							
47	**TRANSMISSION-TOTAL**	33.27%	36.14%	0.20%			
48	Revenue Requirement	91,359,991	101,969,664	559,425		499,595	54 + 60
49	Per NCP kW	1.60	1.82	1.44		1.29	48 / 17
50	Per KWH	0.015	0.016	0.014		0.013	48 / 18
51	Per Customer	123.35	136.02	127.43		113.80	48 / 19
52							

Rocky Mountain Power
State of Utah
Determination of Residential Net Metering Cost of Service
At the Same Basis as Rates Set in Docket No. 13-084-184

Row	Description	Docket No. 13-035-184 Residential Sch 1 @ Step 2 Revenue (A)	Actual 2015 Cost of Service Study With Net Metering Broken Out Sch 1 Non-Net Metering (B)	Actual 2015 Cost of Service Study With Net Metering Broken Out Sch 1 Net Metering (C)	Actual 2015 Cost of Service Study With Net Metering Broken Out Net Metering as a Percentage of Overall Residential (D) (C) / [(B) + (C)]	Sch 1 Net Metering @ GRC Level (E)	Calculation (F)
53	**TRANSMISSION-DEMAND**	34.86%	38.50%	0.21%			
54	Revenue Requirement	72,825,850	82,859,848	442,122	0.531%	386,520	(D) * (A)
55	Per NCP kW	1.28	1.48	1.14		1.00	54 / 17
56	Per KWH	0.012	0.013	0.011		0.010	54 / 18
57	Per Customer	98.33	110.53	100.71		88.05	54 / 19
58							
59	**TRANSMISSION-ENERGY**	28.20%	28.54%	0.18%			
60	Revenue Requirement	18,534,141	19,109,816	117,303	0.610%	113,075	(D) * (A)
61	Per NCP kW	0.33	0.34	0.30		0.29	60 / 17
62	Per KWH	0.003	0.003	0.003		0.003	60 / 18
63	Per Customer	25.02	25.49	26.72		25.76	60 / 19
64							
65	**DISTRIBUTION-TOTAL**	58.04%	59.32%	0.42%			
66	Revenue Requirement	178,074,251	179,610,635	1,270,588		1,257,496	72 + 78 + 84 + 90 + 96
67	Per NCP kW	3.12	3.20	3.28		3.24	66 / 17
68	Per KWH	0.029	0.028	0.032		0.032	66 / 18
69	Per Customer	240.43	239.59	289.43		286.45	66 / 19
70							
71	**DISTRIBUTION-SUBSTATION**	49.83%	51.92%	0.36%			
72	Revenue Requirement	33,930,114	23,397,241	163,677	0.695%	235,711	(D) * (A)
73	Per NCP kW	0.60	0.42	0.42		0.61	72 / 17
74	Per KWH	0.005	0.004	0.004		0.006	72 / 18
75	Per Customer	45.81	31.21	37.28		53.69	72 / 19
76							
77	**DISTRIBUTION- P & C**	56.86%	56.83%	0.38%			
78	Revenue Requirement	81,971,962	88,186,922	594,896	0.670%	549,265	(D) * (A)
79	Per NCP kW	1.44	1.57	1.53		1.42	78 / 17
80	Per KWH	0.013	0.014	0.015		0.014	78 / 18
81	Per Customer	110.68	117.63	135.51		125.12	78 / 19
82							
83	**DISTRIBUTION-TRANSFORMER**	59.50%	60.80%	0.45%			
84	Revenue Requirement	33,141,338	37,976,846	280,395	0.733%	242,899	(D) * (A)
85	Per NCP kW	0.58	0.68	0.72		0.63	84 / 17
86	Per KWH	0.005	0.006	0.007		0.006	84 / 18
87	Per Customer	44.75	50.66	63.87		55.33	84 / 19
88							

Rocky Mountain Power
State of Utah
Determination of Residential Net Metering Cost of Service
At the Same Basis as Rates Set in Docket No. 13-084-184

Row	Description	Docket No. 13-035-184 Residential Sch 1 @ Step 2 Revenue	Actual 2015 Cost of Service Study With Net Metering Broken Out Sch 1 Non-Net Metering	Actual 2015 Cost of Service Study With Net Metering Broken Out Sch 1 Net Metering	Actual 2015 Cost of Service Study With Net Metering Broken Out Net Metering as a Percentage of Overall Residential	Sch 1 Net Metering @ GRC Level	Calculation
		(A)	(B)	(C)	(D) (C) / [(B) + (C)]	(E)	(F)
89	**DISTRIBUTION-SERVICE**	76.18%	76.15%	0.53%			
90	Revenue Requirement	21,440,077	24,178,720	167,230	0.687%	147,270	(D) * (A)
91	Per NCP kW	0.38	0.43	0.43		0.38	90 / 17
92	Per KWH	0.003	0.004	0.004		0.004	90 / 18
93	Per Customer	28.95	32.25	38.09		33.55	90 / 19
94							
95	**DISTRIBUTION-METER**	70.78%	70.26%	0.77%			
96	Revenue Requirement	7,590,759	5,870,907	64,391	1.085%	82,351	(D) * (A)
97	Per NCP kW	0.13	0.10	0.17		0.21	96 / 17
98	Per KWH	0.001	0.001	0.002		0.002	96 / 18
99	Per Customer	10.25	7.83	14.67		18.76	96 / 19
100							
101	**RETAIL-TOTAL**	93.84%	88.98%	1.29%			
102	Revenue Requirement	30,959,030	29,720,071	429,601	1.425%	441,133	(D) * (A)
103	Per NCP kW	0.54	0.53	1.11		1.14	102 / 17
104	Per KWH	0.005	0.005	0.011		0.011	102 / 18
105	Per Customer	41.80	39.64	97.86		100.49	102 / 19
106							
107	**MISC - Total**	39.24%	40.98%	0.23%			
108	Revenue Requirement	5,855,141	3,405,796	18,960	0.554%	32,415	(D) * (A)
109	Per NCP kW	0.10	0.06	0.05		0.08	108 / 17
110	Per KWH	0.001	0.001	0.000		0.001	108 / 18
111	Per Customer	7.91	4.54	4.32		7.38	108 / 19

Rocky Mountain Power
Exhibit RMP___(RMM-8R)
Docket No. 14-035-114
Witness: Robert M. Meredith

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

Exhibit Accompanying Rebuttal Testimony of Robert M. Meredith

Responses to RMP Data Requests

July 2017

14-035-114/ Rocky Mountain Power
February 27, 2017
OCS Data Request 6.8

OCS Data Request 6.8

In Comparing “Summary Table” tab, row 17 in Meredith work papers in “ACOS UT Dec 2015.xlsx” and “A COS UT Dec 2015 NEM Breakout.xlsx” please explain why the “Total Cost of Service” is the same, but the sub-categories “Production Cost of Service”, “Transmission Cost of Service,” etc. have changed. Please explain the billing determinants and/or allocation factors used to get these values to change based on the modeling of a NEM class, but still sum up to the same Total Cost of Service value.

Response to OCS Data Request 6.8

Total cost of service (COS) is the same for both the ACOS and NEM Breakout COS, because both COS studies use the same total level of revenue and calculate total revenue requirement (COS) at the earned rate of return which is based upon present revenues. Please refer to lines 363 through 517 of the Direct Testimony of Company witness, Robert M. Meredith, which provides a discussion of the differences in assumptions for the NEM Breakout COS study. The Company has identified two reasons for the difference in functional COS shown on the tab entitled “Summary Table” of the ACOS and NEM Breakout COS. First, the Company inadvertently used an inconsistent formula for its calculation of the PT and PTD functional factors in the ACOS study. The PT and PTD functional factors should have been based upon normalized results from the jurisdictional allocation model (JAM) instead of actual results from the JAM. Second, COS by function shown on the tab entitled “Summary” of the COS model is calculated by summing up the unbundled revenue requirements by class which incorporates calculations of unbundled revenue by class based upon each class’s earned rate of return and consequent unbundled federal and state income taxes by class. Since the ACOS and NEM Breakout COS contain different class delineations and different assumptions, COS by function as shown on the tab entitled “Summary Table” would still be slightly different after making the correction to the computation of the PT and PTD functional factors in the ACOS study.

Rocky Mountain Power
Docket No. 14-035-114
Witness: Douglas L. Marx

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

Rebuttal Testimony of Douglas L. Marx

July 2017

Q. Are you the same Douglas L. Marx who sponsored direct testimony supporting the Company's application in this proceeding?

A. Yes I am.

Purpose of Rebuttal Testimony

Q. What is the purpose of your rebuttal testimony?

A. My rebuttal testimony responds to the direct testimony of Vote Solar witness Dr. David W. DeRamus, Utah Solar Energy Association ("USEA") witness Micah Stanley, and Vivint Solar witness Richard Collins. I rebut their criticisms of my testimony and challenge their ability to refute technical, engineering principles which they either ignore or are not able to refute.

Rebuttal of Utah Solar Energy Association witness Micah Stanley

Q. Do you agree with Mr. Stanley's statements that all customers benefit when net energy metering ("NEM") customers purchase new transformers or other equipment and if not, why not?

A. I do not agree with Mr. Stanley's broad, unsubstantiated statement. New transformers or other equipment installed for the benefit of a NEM customer do not translate into benefits for other customers. The new equipment only benefits the NEM customer whose system requires additional capacity. In other words, but for the NEM customer's distributed solar generation ("DSG") system, the replaced equipment would have been able to sufficiently handle the load requirements of the other existing customers. The replacements became necessary only due to the reverse power flow caused by the NEM customer's DSG system, which causes the rating of the replaced equipment to exceed its capabilities.

Q. Do you have any comments regarding Mr. Stanley's claim that "the solar industry and NEM customers have invested upwards of $10 million in upgrades to the overall grid?"

A. I thought it was a bold statement and was curious about its source. In response to the Company's request for supporting information, it became clear that there is no data, study, or any other analysis to support his claim. Specifically, USEA responded to the Company's request for supporting information, as follows:

> Mr. Stanley's statement in Direct Testimony is based on his 9 years of experience working in the energy industry and his expertise with providing financing for renewable infrastructure as described in lines 1 through 33. Documentation of these upgrades is not in his possession.[1]

Mr. Stanley's inability to provide support for his "$10 million in upgrades" statement leads me to the conclusion that those numbers are not based on any factual information and should therefore be ignored.

Q. Is there data to support costs that have been incurred or invested by NEM customers for new equipment or "upgrades" to the grid?

A. Yes. Company data shows that NEM customers have invested less than $250,000 of total upgrades to the Company's grid.

[1] RMP data request 1 attached as Exhibit RMP___(DLM-1R).

Q. Mr. Stanley testifies that "every 100 kWh's that the NEM program generates at the residential level is equivalent to 109.32 kWh's of energy generated through traditional means. The Studies fail to account for the value of the 9.32kWh's saved by all customers in that example."[2] Assuming his reference to "the studies" mean the cost of service studies filed by the Company, do you agree with his statement?

A. No. His statement is based on the flawed assumption that no portion of the generation from NEM customers at the residential level is subject to line losses. Only that portion of the customer's generation that is consumed instantaneously and within the premises is not subject to distribution line losses. Any excess generation that leaves the customer's premise is subject to line losses through the distribution system – where the greatest portion of the system losses occur. Further, all replacement energy for excess generation is subject to the full complement of system line losses which further reduces the value of any excess generation.

Q. How do you respond to Mr. Stanley's statements that "[w]hen NEM customers upgrade to new smart meters, they contribute a benefit to non-NEM customers because the new meters reduce the Company's operation costs, including costs associated with remote billing, troubleshooting, and data gathering. For example, smart meters reduce the meter readers' work load because they do not have to inspect each individual meter. Presumably, the Company passes on the associated savings to all customers, including non-NEM customers"?[3]

A. This is another example of Mr. Stanley's broad, conclusory and unsupported statements. The Company has an automatic meter reading system that remotely reads

[2] USEA witness Micah Stanley Direct Testimony, ll. 108-10.
[3] Stanley Direct Testimony, ll. 127-32.

over 98 percent of the meters in Utah. Thus, none of the savings he attributes to "smart meters" are available to the Company. In fact, the meters required by RMP's meter reading system for a NEM account are actually more expensive to install and replace than the meters installed for non-NEM accounts. The installation of more NEM meters will actually increase the Company's meter reading costs.

Rebuttal of Vote Solar witness Dr. David W. DeRamus

Q. What will you be addressing in Dr. DeRamus's testimony?

A. I address errors in his testimony based on technical engineering principles, noting certain popular but erroneous myths, contradictions and false assumptions. In contrast, Dr. DeRamus's testimony appears to be presented from an economist's perspective and is inaccurate from an engineering or technical perspective.

I assume that when Dr. DeRamus discusses the reduced energy consumption of NEM customers, he refers to the delivered energy at the point of interconnection (the electric meter). The introduction of on-site solar generation does not result in load reductions, it only changes the generation source for some of the load requirements.

In his testimony, Dr. DeRamus states "[the Company] significantly overstates the amount of exports by a typical Utah residential NEM customer during the summer (or any other season)."[4] He then contradicts himself when he says "residential NEM customers consumed 19 percent less energy than non-NEM customers, and they *exported 46 percent of a non-NEM customer's consumption*."[5] [Emphasis added]. I would not characterize 46 percent as an overstatement.

Dr. DeRamus further states that "RMP cannot "handle" something it does not

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[4] Vote Solar witness Dr. David DeRamus, Ph.D. Direct Testimony, ll. 700-1.

[5] *Id.* at ll. 715-17.

measure, attempt to control, or otherwise respond to."[6] This mischaracterizes the Company response to a Vote Solar data request he cites as the basis for his statement. Specifically, Vote Solar data request 4.2 asked: "[p]lease provide hourly data showing incremental upstream distribution line use due to excess solar export power flows from NEM solar customers in 2015." RMP responded:

> This data is not available. Metering systems are not capable of differentiating sources of energy generation, and bi-directional flow is only measured at the point of interconnection. [emphasis added].

Thus, Dr. DeRamus's statement that the Company "cannot handle something it doesn't measure" ignores the latter part of the Company's response in which the Company notes that it measures the bi-directional power flow at the customer's meter (*the point of interconnection*). Because this energy is entering the electric grid, RMP must "handle" it while ensuring the integrity of the electric grid. At the current time, energy flow is not measured in the normal course of business along the distribution lines. It is metered at the distribution substation and at customers' premises. Further, any excess generation that is put back to the grid must be accounted for as well as the utility replacement energy generated and delivered when the NEM customer has load requirements that exceed their system's generation ability and when the customer's system cannot generate. Thus, all excess energy is handled twice – when initially received from the NEM customer and again when it is delivered back to them.

Dr. DeRamus then erroneously concludes, "Mr. Marx's assertion that RMP "handles" reverse power flows is therefore entirely speculative and *unsupported by any evidence that such reverse flows exist* [emphasis added]."[7] This statement directly

[6] *Id.* at ll. 995-6.
[7] *Id.* at ll. 1001-3.

contradicts his earlier testimony stating: "I estimated the complete profile of the average NEM customer's usage characteristics, including production, on-site consumption, *energy exported to the grid*, and energy delivered from the grid [emphasis added]."[8]

Dr. DeRamus continues with the popular but erroneous assumption that the neighboring loads consume the NEM customers' exported power before it reaches the upstream distribution system.[9] He offers no proof to substantiate his claim (because such proof does not exist). Once any excess energy passes the NEM customer's electric meter, it enters the distribution system. It cannot be consumed by any other load, even if that load exists next door at the exact time as the excess energy is produced, without traversing RMP's electric distribution system.

Dr. DeRamus acknowledges in his testimony that reverse power flow does exist today.[10] But even assuming the Company did not measure the power flow at the point of interconnection (which is not the case), the insinuation of his statement that "RMP cannot "handle" something it does not measure, attempt to control, or otherwise respond to" (that just because you do not measure something means that it does not exist), is erroneous.

Dr. DeRamus correctly notes that "RMP does not need to measure or manage reverse power flows at *current levels* of residential distributed generation penetration [emphasis added]",[13] but he fails to acknowledge the long-term planning aspects required in utility design and construction. Utility engineers must ensure the designs

[8] *Id.* at ll. 724-6.
[9] *Id.* at ll. 998-1001.
[10] *Id.* at ll. 716-17.

and investments made today will provide safe and reliable service for many decades. Electric systems have life spans that exceed 30 years and it is not uncommon to see facilities with even longer useful lives. His testimony on technical matters is based on simplistic, anecdotal data that is prevalent in the public setting. It demonstrates a lack of technical knowledge and understanding of the dynamics of power flow or the necessary requirements for planning an efficient electric system.

When designing the electric system, with the objective of keeping rates flat or to minimize rate increases while also increasing reliability, engineers must consider the extended life of these assets as they analyze historical data, study industry trends and forecast future needs. These extended asset lives require sophisticated modeling of future systems including running various what-if scenarios, with increasing amounts of distributed generation, to form a basis for investments in the infrastructure.

California is an example of the effect of a large amount of solar energy on power flows and the energy export market created by the high level of solar that exists today. Solar production continues to grow annually and the levels seen today were most likely not planned for thirty years ago. A simple “CAISO duck curve” web query will produce reports that illustrate the challenges electric utilities will face in the future as more solar generation is brought online and as more residential customers seek to become “net-zero” energy consumers with larger, more efficient solar systems if they are not planned for.

Q. You presented two studies that show close to a seven percent reduction in system peak demand yet you did not recommend any changes to the infrastructure to account for this reduction. Why?

A. That is correct. I presented studies for the Northeast #16 circuit showing a seven percent reduction and a study for the Bingham #11 circuit showing a 6.8 percent reduction. While my direct testimony incorrectly stated a reduction of 3.6 percent for the Bingham #11 circuit, it was later corrected through discovery to the 6.8 percent reduction I note here. Based on these studies, I stated "due to this small reduction, and considering the interaction between variable customer load and variations in solar production due to cloud cover and other interference, our distribution planning guidelines will continue to be based on peak load requirements without including solar generation reductions."[11]

Both of these studies were based on "best case" solar and standard temperature conditions with each rooftop "loaded" with as many solar panels as practical and without regard to the actual electrical load or mechanical loading of the individual premise. The studies did not include the effects of solar degradation due to aging panels, increased ambient temperatures, shading, cloud cover, etc. Distributed generation is a variable resource and, due to these changing conditions, cannot be relied upon to support the distribution system at any level that would exceed the calculated "best case" output. Thus, in planning studies the assumption that the distributed generation is not readily available is the most prudent planning approach to ensure system reliability and provide electric service at the time required. Therefore, his argument that it is premature to reach a meaningful conclusion should be given no weight - the studies assumed "best

[11] RMP witness Mr. Douglas Marx Direct Testimony, ll. 50-4.

case" scenarios.

Second, distribution equipment, including transformers and wire, are available in standard sizes. The incremental differences in capacity would not provide for accommodating condition changes in the small magnitude levels shown in these studies. It is evident that a small change in the peak demand on a distribution system would not materially affect the equipment sizes selected.

Q. In your previous testimony, you stated that NEM customers use the grid more than non-NEM customers yet Dr. DeRamus states that your methodology is flawed. How do you respond?

A. Dr. DeRamus states "[a] NEM customer either imports power from the grid or exports excess to the grid, and not both at the same time."[12] In that sentence, he acknowledges that NEM customers do use the grid differently than non-NEM customers. He proceeds to state "[w]hen NEM customers import power from the grid, they use the grid *less* than they would otherwise"[13] followed with "[w]hen NEM customers export power to the grid, they also use the grid less than they would otherwise, because their exported power is consumed by neighboring loads."[14]

My testimony quantified the increased level that a NEM customer uses the grid relative to a non-NEM customer, in terms of kilowatt-hours, for the total amount of energy both imported and exported by a NEM customers. It shows that the sum of those two values, which is the value of energy handled by the system, exceeds the total energy imported by a non-NEM customer. Thus, when accounting for the true use levels, NEM

[12] DeRamus Direct Testimony, ll. 1065-6.
[13] *Id.* at ll. 1068-9.
[14] *Id.* at ll. 1070-2.

customers indeed use the grid more than non-NEM customers and they use it for different purposes.

Q. Dr. DeRamus claims that due to the "different use" characteristics of a NEM customer, NEM actually benefits non-NEM customers. Do you agree?

A. No. There are several errors in his claims. First, he states "they do use the grid differently (at times) than other residential customers; but other residential customers benefit from that "different use," and RMP has submitted no evidence to support the conclusion that this "different use" has caused RMP to incur additional costs."[15] The Company supplied responses to numerous data requests showing the additional costs associated with current NEM customers, attached to my testimony as Exhibit RMP___(DLM-2R).[16] Apparently, Dr. DeRamus has chosen to ignore, this data.

Dr. DeRamus then proceeds to state "[o]n the contrary, the "different use" associated with NEM customers' exports reduces line-loadings on the local distribution network during time periods when that reduction is of value to the system."[17] The Company has demonstrated that the reduction in line loadings is an insignificant amount at the peak times and, when considering the variability of solar generation, the small level of reduction does not translate to any reduction in equipment sizing as required for peak demand periods. Dr. DeRamus continues to base his assumptions on false premises reflecting limited understanding of engineering principles employed in distribution planning.

Lastly he states "[f]urthermore, the recipients of that exported power

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[15] *Id.* at ll. 1078-81.

[16] *See* Vote Solar data requests 1.24, 1.25, 3.7, 3.15-3.18, USEA data requests 2.1-2.3, and Vivint Solar data requests 2.9-2.10.

[17] DeRamus Direct Testimony, ll. 1081-3.

(neighboring customers) obtain that excess energy as if it had come from RMP's resources – and they pay RMP for that power at the full retail rate, i.e., inclusive of embedded transmission and distribution costs, generation capacity and fuel costs, line losses, etc."[18] Dr. DeRamus implies that excess energy does not have to be replaced as required in the net metering tariff and he chooses to ignore the fact that all energy, including excess energy, is subject to line losses as it traverses the distribution system. As stated earlier, all replacement energy for excess generation is subject to line losses which further reduces the value of that excess generation.

He continues with a similar myth that all excess energy produced by NEM customers is consumed by their neighbors. That statement holds true only in limited situations when the neighbors do not produce solar energy (as they could be producing excess at the same time) or when the neighbor's load is sufficiently high enough to require the full amount of excess energy. As more NEM customers approach net-zero generation, the already limited ability for "neighbors" to absorb the excess energy diminishes greatly. Further, as more NEM customers approach net-zero generation, local distribution losses will actually increase. As losses are included in retail rates, this resulting increase would effectively increase those rates passing additional costs to non-NEM customers in Utah.

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[18] *Id.* at ll. 1083-6.

Q. Dr. DeRamus claims that RMP's proposal is not justified because, among other reasons, RMP points to "hypothetical" costs associated with "reverse flows," and because there has been no increase in maintenance activities on the distribution system related to NEM generation. Did the Company include any additional costs associated with "reverse power flows" or with maintenance activities on the distribution system in its costs of service studies as a cost to the NEM program or in the proposed rates?

A. No.

Rebuttal of Vivint Solar witness Richard Collins

Q. Mr. Collins states that you argue that "in May the maximum exported power could be as much as 50 percent more than the maximum imported power in July" and further claims "this argument is a red herring and only applies in limited cases."[19] How do you respond?

A. Mr. Collins' statement misrepresents my testimony. My testimony stated:

> To handle the higher level of energy flow experienced in the spring months, the local distribution system must be sized to accommodate the greater of the two values. Consequently, the system may be sized *up to 30 percent greater* than normal. *In a few cases*, the reverse power flow could approach 50 percent more as compared to the customers' peak load demand [emphasis added].[20]

Mr. Collins goes on to state that "only 13 percent of all [current] net metered customers are zero net energy."[21] That is not an insignificant number today and especially when one considers the potential for larger, more efficient systems being installed as solar panel efficiencies increase and panel prices continue to decrease,

[19] Collins Direct Testimony, ll. 737-39.

[20] Marx Direct Testimony, ll. 73-7.

[21] Collins Direct Testimony, l. 746.

making these installations more economical. There are long term planning aspects required in utility design and construction and RMP routinely analyzes several possible scenarios to understand future impacts. The potential for an increase in export power demand levels at the distribution level during spring months is real and must be considered. The Company will continue to study the effects of distributed generation on RMP's system through planning studies and when the time comes that these negative impacts become more pronounced, we will be in a better position to address them and ensure continued reliability of the electric system.

Q. Mr. Collins states that if "one or two customers on the transformer are a non-NEM customer or less than full zero net energy customer, then the exported power from the NEM customer will simply negate the inflow of power to the non-Net metering customers."[22] Do you agree?

A. No. His statement is only true within very limited parameters and highly dependent on the number of customers connected to the transformer and then, only to the extent that those non-NEM customers have the load requirements to absorb that exported power. A residential customer's load is typically at the lowest point during the spring and fall months. This is also the time when the solar panels have their highest generation output. As stated earlier, we will continue to analyze and plan for several factors across the electric system.

Q. Mr. Collins states that the seven percent peak demand reduction "may delay the need for future upgrades to the circuit."[23] Is this true?

A. That's a very ambiguous statement with no framing around "delay the need" and the

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[22] *Id*. at ll. 741-4.
[23] *Id*. at ll. 749-50.

operative word is “may.” As I stated in my rebuttal of Dr. DeRamus’s testimony, these studies were based on “best case” solar and standard temperature conditions. The studies did not include the effects of solar degradation due to aging panels, increased ambient temperatures, shading, cloud cover, etc. Distributed generation is a variable resource and, due to these changing conditions, would not be relied upon to support the distribution system at any level that would exceed the calculated “best case” output. Furthermore, the system dynamics change year on year. With the addition of new loads, shifting usage characteristics associated with increasing spring or fall solar generation levels, and associated system requirements for protection and control to ensure system reliability, this “may” actually accelerate upgrades to the circuits.

Q. Please summarize your rebuttal testimony.

A. While the current level of NEM customers found on RMP’s distribution system does not require immediate action to manage or mitigate potential operational effects, testimony has shown that increasing levels will have a negative and costly effect on the distribution system. Residential rooftop solar generation does not reduce the distribution peak demand experienced by the electric grid to a degree that could warrant a reduction in infrastructure and could actually increase the base requirements for infrastructure at the local level. I have shown that the “different use” by NEM customers is quantifiable and exceeds that of non-NEM customers and the excess energy must be handled and managed by the Company on the customer’s behalf. Furthermore, I have dispelled the myth that excess residential solar energy is consumed by the neighbors. In fact, as more customers and neighborhoods approach “net-zero” energy profiles, the excess energy will continue to propagate further into the distribution system and is subject to higher line losses than seen today. When all these factors are considered, the introduction of large amounts of NEM distributed generation does not produce system benefits and increases operational costs.

Q. Does this conclude your rebuttal testimony?

A. Yes.

Rocky Mountain Power
Exhibit RMP___(DLM-1R)
Docket No. 14-035-114
Witness: Douglas L. Marx

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

Exhibit Accompanying Rebuttal Testimony of Douglas L. Marx

USEA Response to RMP Data Request

July 2017

14-035-114 / USEA
June 27, 2017
RMP Data Request 1

RMP Data Request 1

On lines 96 and 97 of Mr. Stanley's Direct Testimony, he asserts: "In fact, the solar industry and NEM customers have invested upwards of $10 Million in upgrades to the overall grid." Please provide all information, documents or other support for this claim, including all work papers, studies, or analysis with formulate intact.

Response to RMP Data Request 1

Mr. Stanley's statement in Direct Testimony is based on his 9 years of experience working in the energy industry and his expertise with providing financing for renewable infrastructure as described in lines 1 through 33. Documentation of these upgrades is not in his possession.

Rocky Mountain Power
Exhibit RMP___(DLM-2R)
Docket No. 14-035-114
Witness: Douglas L. Marx

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

Exhibit Accompanying Rebuttal Testimony of Douglas L. Marx

RMP Responses to Data Requests

July 2017

14-035-114/ Rocky Mountain Power
February 21, 2017
Vote Solar Data Request 1.24

Vote Solar Data Request 1.24

Please confirm our understanding from the January 23 technical conference that there has been only one secondary transformer upgrade resulting from a residential solar installation.

(a) Please provide the actual values for each of the cost components of the transformer upgrade (as outlined in subpart (b) above in the previous question).

(b) Please describe the circumstances necessitating the upgrade, including the number of customers (and whether residential or commercial) served by the transformer.

Response to Vote Solar Data Request 1.24

(a) The average cost of a transformer upgrade was $8,757. The average salvage value of a replaced transformer was $705.

(b) Upgrades are assessed on a case by case basis and are the same for residential or commercial sites. Upgrades are required if the sum of generation will overload the transformer beyond rated capacity.

14-035-114/ Rocky Mountain Power
March 30, 2017
Vote Solar Data Request 3.7

Vote Solar Data Request 3.7

Follow up to RMP response to DPU6.5:

(a) Please provide the calculation referenced in the response to DPU6.5(a).

(b) For each upgrade whose costs are included in the $251,166 (response to DPU6.5(b)), please identify the reason for the upgrade, the class and rate sheet of the customer(s) causing the upgrade, an accounting of the equipment upgraded, and an accounting of the cost of each upgrade.

Response to Vote Solar Data Request 3.7

(a) See response to EFCA 1.25.

(b) During review of the data it was determined that two projects may have been mis-coded and should not have been included in the original submittal. The revised total $240,092. See Attachment Vote Solar 3.7.

UT 14-035-114
Vote Solar 3.7

Attachment Vote Solar 3.7

Project	Reason	Customer Class	Equipment Upgraded	Total Cost of Work
1	Overload	Commercial	Transformer	$ 13,219
2	Overload	Commercial	Transformer	9,476
3	Overload	Commercial	Transformer	10,729
4	Overload	Commercial	Transformer	10,211
5	Overload	Residential	Transformer	3,049
6	Overload	Commercial	Transformer	3,359
7	Overload	Residential	Transformer	5,775
8	Overload	Residential	Transformer	6,059
9	Overload	Commercial	Transformer	9,639
10	Overload	Commercial	Transformer	30,211
11	Overload	Commercial	Transformer	24,538
12	Overload	Commercial	Transformer	27,527
13	Overload	Commercial	Transformer	4,625
14	Overload	Residential	Transformer	5,108
15	Overload	Commercial	Transformer	9,782
16	Overload	Residential	Transformer	5,912
17	Overload	Residential	Transformer	4,217
18	Overload	Commercial	Transformer	4,095
19	Overload	Residential	Transformer	5,302
20	Overload	Residential	Transformer	3,640
21	Overload	Residential	Transformer	5,126
22	Overload	Commercial	Transformer	3,784
23	Overload	Commercial	Transformer	10,290
24	Overload	Commercial	Transformer	5,522
25	Overload	Residential	Transformer	2,046
26	Overload	Residential	Transformer	4,443
27	Overload	Commercial	Wire	1,693
28	Overload	Commercial	Transformer	2,780
29	Reverse Energy Flow	Commercial	Regulator Controls	7,936

14-035-114/ Rocky Mountain Power
March 30, 2017
Vote Solar Data Request 3.15

Vote Solar Data Request 3.15

As a follow up to Vote Solar 1.23:

(a) In a typical secondary transformer upgrade situation, what would be the expected change in transformer capacity?

(b) How many secondary transformer upgrades have there been over the past five years?

(c) Of the transformers removed in the upgrades identified in (b), please identify the number of years each has been in service at the time of removal, and how many have been reused elsewhere on the RMP system?

(d) What happens to the transformers not reused on the RMP system? If such equipment is sold for scrap metal, how is the revenue received from such sales reflected in the cost of service, and allocated to customer classes?

Response to Vote Solar Data Request 3.15

(a) Upgrades for distribution transformers used in residential applications are 25 kVA increments.

(b) There have been 27 transformers upgraded for solar installations since 2012. No data is available for solar upgrades prior to this time.

(c) This data is not available. Distribution transformers are tracked as an asset class, not by individual units.

(d) Transformers not reused are sold to rebuilders or scrap dealers. Salvage values are credited to the transformer capital account.

14-035-114/ Rocky Mountain Power
March 30, 2017
Vote Solar Data Request 3.16

Vote Solar Data Request 3.16

As a follow up to Vote Solar 1-24, please confirm our understanding from the January 23 technical conference that there has been only one secondary transformer upgrade resulting from a residential solar installation.

Response to Vote Solar Data Request 3.16

See response to Vivint 2.9.

14-035-114/ Rocky Mountain Power
March 30, 2017
Vote Solar Data Request 3.17

Vote Solar Data Request 3.17

Please identify the number of secondary transformer upgrades resulting from a commercial solar installation.

Response to Vote Solar Data Request 3.17

There have been 16 transformers upgraded for commercial solar installations since 2012. No data is available for solar upgrades prior to this time.

14-035-114/ Rocky Mountain Power
March 30, 2017
Vote Solar Data Request 3.18

Vote Solar Data Request 3.18

As a follow up to Vote Solar 1-25, please identify the costs of each of the ten upgrades noted in the response, and how such costs were recovered.

Response to Vote Solar Data Request 3.18

Please see Attachment Vote Solar 3.18.

UT 14-035-114
Vote Solar 3.18

Attachment Vote Solar 3.18

Project	Customer Class	Total Cost of Work
A	Residential	$ 1,140
B	Residential	421
C	Commercial	1,272
D	Commercial	3,455
E	Commercial	765
F	Commercial	1,693
G	Commercial	1,793
H	Commercial	2,317
I	Commercial	218
J	Commercial	779

14-035-114/ Rocky Mountain Power
February 20, 2017
Vivint Solar Data Request 2.9

Vivint Solar Data Request 2.9

Please state how many transformer upgrades have been required as a result of rooftop solar systems in RMP's service territory.

(a) Please provide the average cost of each transformer upgrade.

(b) Please provide the salvage value of the replaced transformer.

(c) What is the typical solar saturation level required, by transformer type, to require a transformer upgrade?

(d) Please explain who bares the full cost of the transformer upgrade.

Response to Vivint Solar Data Request 2.9

To date, 26 transformers have been upgraded.

(a) The average cost of a transformer upgrade was $8,757.

(b) The average salvage value of a replaced transformer was $705.

(c) When the total connected solar overloads the transformer beyond rated capacity a transformer upgrade would be required.

(d) The customer whose solar installation causes the overload condition per Rocky Mountain Power (RMP) Electric Service Regulation No. 1, State of Utah.

14-035-114/ Rocky Mountain Power
February 20, 2017
Vivint Solar Data Request 2.10

Vivint Solar Data Request 2.10

Please provide the number of secondary line upgrades that have been required as a result of rooftop solar systems in RMP's service territory.

(a) Please provide the average cost of each line upgrade.

(b) What is the typical solar saturation level required to require a line upgrade?

(c) Please explain who bares the full cost of the line upgrade.

(d) Please provide supporting data.

Response to Vivint Solar Data Request 2.10

To date, 10 secondary lines have been upgraded.

(a) The average cost of a secondary line upgrade was $1,385.

(b) When the total connected solar overloads the secondary line beyond rated capacity a line upgrade would be required.

(c) The customer whose solar installation causes the overload condition per Rocky Mountain Power (RMP) Electric Service Regulation No. 1, State of Utah.

(d) RMP Utah Electric Service Regulation No. 1.

14-035-114/ Rocky Mountain Power
May 9, 2017
USEA Data Request 2.1

USEA Data Request 2.1

Please identify *by class* how many substations, transformers, and service upgrades, were requested and inspected by RMP during the test period applicable to the ACOS and CFCOS (the "Test Period").

Response to USEA Data Request 2.1

There were six commercial class transformer upgrades and one residential class transformer upgrade required in calendar year 2015.

14-035-114/ Rocky Mountain Power
May 9, 2017
USEA Data Request 2.2

USEA Data Request 2.2

For each request or inspection identified in response to Request No. 2.1, please provide an accounting that includes:

(a) the date the request or inspection was made;
(b) the corresponding customer's name and/or account number;
(c) where applicable, the name of the contractor performing the service; and
(d) where applicable, the technology upgrade required for approval.

Response to USEA Data Request 2.2

See the following table for the requested details:

USEA 2.2(a)	USEA 2.2(b)	USEA 2.2(c)	USEA 2.2(d)	USEA 2.3	
Date Initiated	Site ID	Contractor	Equipment Upgraded	Customer Count	
				NEM	Non-NEM
9/30/2015	252579032 001	RMP Crews	Transformer[1]	2	1
2/4/2015	363936202 001	RMP Crews	Transformer	1	0
8/10/2015	148624534 001	RMP Crews	Transformer	1	0
8/26/2015	021340799 001	RMP Crews	Transformer	1	0
10/30/2015	401893076 001	Sturgeon	Transformer	1	0
12/23/2015	905843411 001	RMP Crews	Transformer	1	1
10/30/2015	723465739 001	RMP Crews	Transformer	2	0

[1]Residential upgrade. All others are commercial.

14-035-114/ Rocky Mountain Power
May 9, 2017
USEA Data Request 2.3

USEA Data Request 2.3

For each upgrade paid for by a net-metering customer, please provide the number of non net-metering customers and the amount of kW used by non net-metering customers that benefited from the upgrade.

Response to USEA Data Request 2.3

See USEA 2.2 for customer counts. This count shows net metering and non-net metering customers served by the transformer. The upgrades were completed solely for the benefit of the net metering customer to serve their needs.

Rocky Mountain Power
Docket No. 14-035-114
Witness: Michael G. Wilding

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

Rebuttal Testimony of Michael G. Wilding

July 2017

Q. Are you the same Michael G. Wilding who submitted direct testimony on behalf of the Company in this proceeding?

A. Yes.

Q. What is the purpose of your rebuttal testimony?

A. My testimony presents and supports certain updates to the Company's net power cost ("NPC") analysis of the net metering program ("NEM Program") for the 12-month period from January 1, 2015 through December 31, 2015 ("Study Period"). Specifically, I discuss NPC results with: 1) updated integration costs based on the 2017 Integrated Resource Plan ("IRP"), and 2) the addition of variable operations and maintenance ("O&M") costs for coal and gas plant operation.

In addition, my testimony responds to issues raised by the Energy Freedom Coalition of America witness Eliah Gilfenbaum, HEAL Utah witness Jeremy Fisher, Vivint Solar ("Vivint") witnesses Tom Plagemann and Richard Collins, and Vote Solar witness David DeRamus. In particular, I address the following:

1. Integration Costs – Vivint, Vote Solar, and HEAL Utah point out that the integration cost assumptions used in the NPC analysis are higher than those in the 2017 IRP.[1] The Company concurs and the NPC analysis has been updated to be consistent with the recently filed 2017 IRP of $0.60/MWh.
2. Variable O&M Costs – HEAL Utah, Vivint, and Vote Solar recommend the Company include variable O&M production costs in our unit dispatch costs.[2] The

[1] Vivint Solar witness Richard Collins Direct Testimony, ll. 529-57; Vote Solar witness David W. DeRamus Direct Testimony, ll. 878-81; HEAL Utah witness Jeremy Fisher Direct Testimony p. 9-10.
[2] Collins Direct Testimony, ll. 490-504; DeRamus Direct Testimony, ll. 876-7.

NPC analysis has been updated to include annual variable O&M costs for coal and gas units.

3. NPC Analysis – The parties shared a common concern that the NPC analysis does not capture all benefits of the NEM Program. Specifically, I address the following:
   - Capacity benefit provided by the NEM Program: The Company is resource sufficient until 2029 and therefore the capacity benefit is properly captured in the NPC analysis.
   - Resource mix to serve incremental load: The Company used its Generation and Regulation Initiative Decision Tools ("GRID") production cost model to determine the resource mix to serve incremental load associated with the NEM Program. GRID has been used in all general rate cases since 2003. The costs associated with each resource type are 2015 actual NPC.

Updated NPC Analysis

Q. Has the Company updated its NPC analysis and provided supporting exhibits and workpapers?

A. Yes. Exhibit RMP___(MGW-1R) contains the updated NPC analysis of the NEM Program for the Study Period, which includes the solar integration cost from the 2017 IRP and variable O&M costs.

Q. What is the result of the updated NPC analysis?

A. Updating the NPC analysis to include variable O&M and the solar integration costs from the 2017 IRP increases the NPC benefit to $24.87/MWh, or $1.44 million as seen in Lines 45 and 46 of Exhibit RMP___(MGW-1R) and summarized in Table 1 below. The difference from the original filing is approximately $150,000.

TABLE 1

2015 NPC NEM Analysis

NPC Component	Change (MWh)	2015 Actual NPC Weighted ($/MWh)	2015 NPC Benefit of Solar
System Balancing Sales	22,471	$ 9.90	
System Balancing Purchases	17,233	$ 7.60	
Coal Generation/Fuel Expense + Variable O&M	16,900	$ 7.45	
Natural Gas Generation/Fuel Expense + Variable O&M	1,182	$ 0.52	
Integration Costs		$ (0.60)	
Total	57,785	**$ 24.87**	**$ 1,437,202**

Integration Costs

Q. Why did the Company update the integration costs from its previous filing?

A. Vivint, Vote Solar, and HEAL Utah each proposed the NPC analysis be updated to reflect the solar integration costs from the recently filed IRP. At the time of the compliance filing in November 2016, the NPC analysis referenced the most current source for integration costs previously approved by the Commission in Docket No. 12-035-100 (the "QF Docket").[3] On April 4, 2017, the Company filed its 2017 IRP which reflects the Company's current assumptions about future costs. Solar integration costs were updated from $2.83/MWh to $0.60/MWh,[4] which results in an increased benefit for the NEM Program. The 2017 IRP has not yet been acknowledged by the Commission, but the Company is updating to provide the most current integration costs.

[3] *See* Docket No. 12-035-100, Order on Phase II Issues, at 34 (Utah P.S.C. August 16, 2013). In the QF Docket, the Commission approved, among other things, solar integration charges the equivalent of 65 percent and 50 percent of wind integration charges for fixed solar and tracking solar resources, respectively, from the Company's 2012 Wind Integration Study (the "Phase II Order").

[4] Integrated Resource Plan - Volume II, Appendices, Appendix F - Flexible Reserve Study, p. 75. The IRP has integration cost of $0.60/MWh (*see* Exhibit RMP__(MGW-1R) line 44).

Variable O&M Costs

Q. How were the variable O&M costs included in the analysis?

A. To the extent that the NEM program avoids variable O&M costs, the annual weighted average variable O&M cost for coal and natural gas plants were added to the 2015 actual unit costs for coal and natural gas, respectively. This is reflected in Lines 38 and 39 of Exhibit RMP___(MGW-1R). The result was an annual weighted average variable O&M cost of $1.22/MWh for coal plants and $0.24/MWh for gas plants, respectively.

Q. What costs are included in variable O&M costs?

A. The variable O&M costs for natural gas plants are comprised of chemical costs and water. The variable O&M costs for coal plants include chemical costs and ash handling.

NPC Analysis

Q. Did the Company consider the impact of the NEM Program on avoided generation capacity?

A. Yes. There are no avoided capacity costs from the NEM Program generation because there are no deferrable capacity investments. The carrying cost of new generation capacity should be included only during periods of resource deficiency requiring capacity investments. Deficiency period is identified as the next major thermal resource acquisition in the Company's latest IRP filing. In the recent update to Utah Schedule 37 tariff filing, the deficiency period is 2029 based on the first major thermal resource in the 2017 IRP.[5]

In addition, when the GRID model is used to calculate the marginal cost of energy, as was done in this case, the marginal energy costs capture the ability of the

[5] *See* Docket No. 17-035-T07, RMP updated schedule 37 Tariff Sheets Using Current Methodology.

capacity resource to be dispatched into the market, as well as any reduction in market sales related to the deferral of such capacity, therefore no additional adjustment is needed.

Q. Can the capacity value of the NEM Program be valued using the California Public Utility Commission ("CPUC") resource adequacy ("RA") process?

A. No. Vivint suggests the capacity of the NEM Program be valued using the CPUC RA process because PacifiCorp has available transmission into California. The value used for capacity pricing is a California Independent System Operator ("CAISO") price and the Company is not a member of the CAISO. In fact, the source of the capacity pricing is a technical report discussing the benefits of integration with CAISO.[6] In addition, the Company neither owns nor controls the NEM program resources and therefore the Company would not be able to bid the resources into a capacity market. Furthermore, the Company uses its resources to serve load and not to bid into CAISO.

Q. How did the Company determine the resource mix that would serve the incremental load if there was no generation from the NEM Program?

A. The Company performed two GRID studies, a base study and a study without generation from the NEM Program ("No NEM Study"), and compared the change in resources between the two studies. The study period was calendar year 2015, consistent with the Commission's November 10, 2015 Order.[7]

Q. Can you please provide an overview of what the GRID model does?

A. GRID is an hourly production cost dispatch model that dispatches PacifiCorp resources

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[6] https://www.caiso.com/Documents/Study-TechnicalAppendix-Benefits-PacifiCorp-ISOIntegration.PDF.

[7] *See* Docket No. 14-035-114, Order (November 10, 2015), where the Commission adopted the analytical framework.

to serve its load obligation through the most economic means possible given the constraints of the Company's system. GRID has been used in every GRC the Company has filed in Utah since 2003.

Q. Does GRID choose the highest cost resource to serve incremental load in the No NEM Study?

A. No. The GRID model optimizes all Company resources to meet the additional load at the lowest possible cost. Vote Solar states that "[i]t is more reasonable to expect that the output from the [distribute generation] reduces the marginal (highest cost) output at the top of the stack."[8] The No NEM study did choose the marginal resource but this is not the same as the highest cost. For example, the next resource in the stack with available capacity was a coal unit, however there are more expensive resources that are either being used to hold reserves or are not dispatched for economic purposes.

Q. Vote Solar claims there is an error in the NPC analysis because GRID uses an average heat rate rather than a marginal heat rate.[9] Please explain the heat rate function in the GRID model.

A. A heat rate curve identifying a unit's heat rate as a function of unit output is input into the GRID model, and the dispatch is based on the incremental/marginal heat rate over a unit's dispatchable range (i.e. the average incremental/marginal heat rate between minimum and maximum dispatch). This allows a unit's dispatch cost to be reflected as a single value which is necessary for computation in the linear program logic. After a unit's hourly dispatch is determined, the GRID model reports fuel consumption based

[8] DeRamus Direct Testimony, ll. 874-6.

[9] DeRamus Direct Testimony, l. 877.

on the heat rate specific to that level of dispatch.

Q. What is the source of the costs associated with the change in resources in the NPC analysis?

A. The costs used in the NPC analysis are the 2015 actual NPC. HEAL Utah points out some differences in costs in the GRID studies and actuals;[10] however, these differences are inconsequential as the NPC analysis relies on actual NPC.

Q. Does this conclude your direct testimony?

A. Yes.

[10] Fisher Direct Testimony, p.12.

Rocky Mountain Power
Exhibit RMP___(MGW-1R)
Docket No. 14-035-114
Witness: Michael G. Wilding

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

Exhibit Accompanying Rebuttal Testimony of Michael G. Wilding

Revised NPC Analysis

July 2017

Rocky Mountain Power
Exhibit RMP___(MGW-1R) Page 1 of 1
Docket No. 14-035-114
Witness: Michael G. Wilding

Exhibit RMP__(MGW-1R) (Updated Integration Costs and Variable O&M)
Net Power Cost Analysis of the Net Metering Program
Study Period: January - December 2015

Line No.		Reference	Units	Jan-15	Feb-15	Mar-15	Apr-15	May-15	Jun-15	Jul-15	Aug-15	Sep-15	Oct-15	Nov-15	Dec-15	Total
	Change in Net Power Costs Between															
	Dollars ($)															
1	System Balancing Sales		$	$ 5,869	$ 8,209	$ 12,076	$ 47,324	$ 36,868	$ 39,515	$ 157,538	$ 145,566	$ 86,041	$ 54,968	$ 26,775	$ 25,896	
2	System Balancing Purchases		$	$ 26,884	$ 30,678	$ 40,649	$ 32,244	$ 34,334	$ 103,092	$ 64,497	$ 72,274	$ 8,422	$ 17,317	$ 14,226	$ 5,025	
3	Coal Fuel Burn Expense		$	$ 11,650	$ 20,859	$ 35,924	$ 20,319	$ 38,666	$ 30,063	$ 9,020	$ 10,100	$ 67,054	$ 60,742	$ 43,065	$ 21,920	
4	Gas Fuel Burn Expense		$	$ 937	$ 2,483	$ 5,366	$ 2,797	$ 3,706	$ 24	$ 2,319	$ 26	$ (282)	$ 2,178	$ 5,643	$ (642)	
5	Change in Net Power Cost	∑ Lines 1:4	$	$ 45,340	$ 62,230	$ 94,015	$ 102,683	$ 113,573	$ 172,694	$ 233,374	$ 227,966	$ 161,236	$ 135,205	$ 89,709	$ 52,200	
	Change in Energy Between Base Study															
6	System Balancing Sales		MWh	256	411	559	2,380	1,594	1,490	4,493	4,045	2,957	2,137	1,067	1,082	
7	System Balancing Purchases		MWh	1,177	1,576	2,014	1,604	1,551	3,786	1,747	1,990	332	658	579	218	
8	Coal Generation		MWh	510	1,046	1,781	1,019	1,808	1,370	358	436	2,906	2,693	1,990	985	
9	Gas Generation		MWh	45	134	289	224	162	(47)	68	(38)	(24)	155	255	(41)	
10	UT Net Metering Solar Generation	∑ Lines 6:9	MWh	**1,989**	**3,166**	**4,642**	**5,227**	**5,115**	**6,599**	**6,665**	**6,433**	**6,170**	**5,643**	**3,891**	**2,244**	**57,785**
	Unit Costs ($)/(MWh) of Change Between Base Study and No NEM Study															
11	System Balancing Sales	Line 1 / Line 6	$/MWh	$ 22.92	$ 19.97	$ 21.61	$ 19.89	$ 23.13	$ 26.52	$ 35.06	$ 35.99	$ 29.09	$ 25.73	$ 25.09	$ 23.93	
12	System Balancing Purchases	Line 2 / Line 7	$/MWh	$ 22.83	$ 19.47	$ 20.18	$ 20.10	$ 22.13	$ 27.23	$ 36.92	$ 36.31	$ 25.40	$ 26.30	$ 24.56	$ 23.09	
13	Coal Fuel Burn Expense	Line 3 / Line 8	$/MWh	$ 22.83	$ 19.95	$ 20.17	$ 19.94	$ 21.39	$ 21.94	$ 25.22	$ 23.17	$ 23.08	$ 22.56	$ 21.64	$ 22.26	
14	Gas Fuel Burn Expense	Line 4 / Line 9	$/MWh	$ 20.71	$ 18.54	$ 18.58	$ 12.50	$ 22.82	$ (0.50)	$ 34.12	$ (0.70)	$ 11.55	$ 14.08	$ 22.15	$ 15.83	
15	Total Unit Costs $/MWH	Line 5 / Line 10	$/MWh	$ 22.79	$ 19.65	$ 20.25	$ 19.65	$ 22.20	$ 26.17	$ 35.01	$ 35.44	$ 26.13	$ 23.96	$ 23.06	$ 23.26	
	Percentage Change or Weight of NPC															
16	System Balancing Sales	Line 6 / Line 10	%	**12.87%**	**12.98%**	**12.04%**	**45.53%**	**31.16%**	**22.58%**	**67.41%**	**62.87%**	**47.93%**	**37.87%**	**27.42%**	**48.23%**	
17	System Balancing Purchases	Line 7 / Line 10	%	**59.19%**	**49.76%**	**43.38%**	**30.69%**	**30.33%**	**57.38%**	**26.21%**	**30.94%**	**5.37%**	**11.67%**	**14.89%**	**9.70%**	
18	Coal Generation	Line 8 / Line 10	%	**25.66%**	**33.02%**	**38.36%**	**19.49%**	**35.34%**	**20.76%**	**5.37%**	**6.78%**	**47.09%**	**47.72%**	**51.14%**	**43.88%**	
19	Gas Generation	Line 9 / Line 10	%	**2.28%**	**4.23%**	**6.22%**	**4.28%**	**3.17%**	**-0.72%**	**1.02%**	**-0.59%**	**-0.40%**	**2.74%**	**6.55%**	**-1.81%**	
20	Total	∑ Lines 16:19	%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	
	Market Transactions															
	Base Palo Verde Market Price															
21	UT Net Metering Generation HLH		MWh	1,697	2,638	3,890	4,493	3,968	5,673	5,562	5,423	5,055	4,917	2,970	1,894	
22	UT Net Metering Generation LLH		MWh	292	529	753	734	1,147	925	1,103	1,010	1,115	726	921	350	
23	Base Palo Verde HLH		$/MWh	$ 25.79	$ 24.17	$ 25.07	$ 24.00	$ 26.75	$ 28.50	$ 34.65	$ 34.32	$ 30.03	$ 28.05	$ 27.23	$ 27.23	
24	Base Palo Verde LLH		$/MWh	$ 24.10	$ 21.45	$ 21.90	$ 21.50	$ 21.25	$ 21.25	$ 24.50	$ 25.49	$ 24.01	$ 24.72	$ 23.52	$ 23.76	
25	Base Palo Verde Market Price	(Line 21 * Line 23 +Line 22 * Line 24) / (Line 21 + Line 22)	$/MWh	$ 25.54	$ 23.72	$ 24.56	$ 23.65	$ 25.52	$ 27.48	$ 32.97	$ 32.94	$ 28.94	$ 27.62	$ 26.35	$ 26.70	
26	Unit Cost Change of Market Transactions	(Line 1 + Line 2) / (Line 6 + Line 7)	$/MWh	$ 22.85	$ 19.57	$ 20.49	$ 19.97	$ 22.64	$ 27.03	$ 35.59	$ 36.10	$ 28.72	$ 25.86	$ 24.91	$ 23.79	
27	Unit Cost Change of Market Transactions Compared to Base Palo Verde Market Price	Line 26 / Line 25	%	89.5%	82.5%	83.4%	84.4%	88.7%	98.4%	107.9%	109.6%	99.2%	93.6%	94.5%	89.1%	
	Actual Palo Verde Market Price															
28	UT Net Metering Generation HLH	Line 21	MWh	1,697	2,638	3,890	4,493	3,968	5,673	5,562	5,423	5,055	4,917	2,970	1,894	
29	UT Net Metering Generation LLH	Line 22	MWh	292	529	753	734	1,147	925	1,103	1,010	1,115	726	921	350	
30	Actual Palo Verde HLH		$/MWh	$ 25.79	$ 24.17	$ 25.07	$ 24.05	$ 24.04	$ 31.72	$ 34.02	$ 34.98	$ 29.72	$ 26.90	$ 22.69	$ 21.59	
31	Actual Palo Verde LLH		$/MWh	$ 24.42	$ 21.54	$ 22.08	$ 21.61	$ 21.02	$ 22.24	$ 24.72	$ 24.91	$ 23.56	$ 21.70	$ 20.65	$ 19.21	
32	Actual Palo Verde Market Price	(Line 28 * Line 30 +Line 29 * Line 31) / (Line 28 + Line 29)	$/MWh	$ 25.58	$ 23.73	$ 24.59	$ 23.71	$ 23.36	$ 30.39	$ 32.48	$ 33.40	$ 28.61	$ 26.23	$ 22.21	$ 21.22	
33	Adjusted Actual Palo Verde Market Price	Line 27 * Line 22	$/MWh	**$ 22.89**	**$ 19.59**	**$ 20.52**	**$ 20.02**	**$ 20.73**	**$ 29.89**	**$ 35.06**	**$ 36.60**	**$ 28.39**	**$ 24.56**	**$ 21.00**	**$ 18.90**	
	2015 Actual NPC															
	Dollars ($000)															
34	Coal Fuel Burn Expense	Exhibit RMP___(MGW-4) Row 139	$ ('000s)	$ 71,690	$ 61,222	$ 70,591	$ 65,574	$ 66,951	$ 69,888	$ 70,614	$ 71,953	$ 64,237	$ 59,312	$ 56,905	$ 68,248	$ 797,186
35	Natural Gas Fuel Burn Expense	Exhibit RMP___(MGW-4) Row 150	$ ('000s)	$ 24,309	$ 19,353	$ 19,892	$ 18,448	$ 21,287	$ 24,536	$ 28,498	$ 27,849	$ 26,574	$ 22,964	$ 21,945	$ 23,024	$ 278,679
	Energy (MWh 000)															
36	Coal Generation	Exhibit RMP___(MGW-4) Row 289	MWh ('000s)	3,657	3,166	3,540	3,333	3,394	3,618	3,627	3,716	3,450	3,164	3,021	3,613	41,301
37	Natural Gas Generation	Exhibit RMP___(MGW-4) Row 300	MWh ('000s)	692	492	492	588	722	872	996	939	907	818	830	879	9,226
	Actual Unit Costs ($)/(MWh)															
38	Coal Fuel Burn Expense + Variable O&M	(Line 34 / Line 36) + $1.22	$/MWh	**$ 20.82**	**$ 20.55**	**$ 21.16**	**$ 20.89**	**$ 20.94**	**$ 20.53**	**$ 20.68**	**$ 20.58**	**$ 19.84**	**$ 19.96**	**$ 20.05**	**$ 20.10**	**$ 20.52**
39	Natural Gas Fuel Burn Expense + Variable O&M	(Line 35 / Line 37) + $0.24	$/MWh	**$ 35.38**	**$ 39.61**	**$ 40.64**	**$ 31.62**	**$ 29.73**	**$ 28.37**	**$ 28.85**	**$ 29.91**	**$ 29.54**	**$ 28.31**	**$ 26.69**	**$ 26.45**	**$ 30.45**
	NPC Unit Benefit of Net Metering Generation															
40	Unit Value of Solar - Sales	Line 33 * Line 16	$/MWh	$ 2.95	$ 2.54	$ 2.47	$ 9.12	$ 6.46	$ 6.75	$ 23.63	$ 23.01	$ 13.61	$ 9.30	$ 5.76	$ 9.12	
41	Unit Value of Solar - Purchases	Line 33 * Line 17	$/MWh	$ 13.55	$ 9.75	$ 8.90	$ 6.14	$ 6.28	$ 17.15	$ 9.19	$ 11.32	$ 1.53	$ 2.87	$ 3.13	$ 1.83	
42	Unit Value of Solar - Coal	Line 38 * Line 18	$/MWh	$ 5.34	$ 6.79	$ 8.12	$ 4.07	$ 7.40	$ 4.26	$ 1.11	$ 1.39	$ 9.34	$ 9.53	$ 10.26	$ 8.82	
43	Unit Value of Solar - Gas	Line 39 * Line 19	$/MWh	$ 0.80	$ 1.68	$ 2.53	$ 1.35	$ 0.94	$ (0.20)	$ 0.29	$ (0.18)	$ (0.12)	$ 0.78	$ 1.75	$ (0.48)	
44	Integration Cost - Fixed Solar		$/MWh	$ (0.60)	$ (0.60)	$ (0.60)	$ (0.60)	$ (0.60)	$ (0.60)	$ (0.60)	$ (0.60)	$ (0.60)	$ (0.60)	$ (0.60)	$ (0.60)	
45	Total Unit Value of Solar $/MWH	∑ Lines 40:44	$/MWh	**$ 22.04**	**$ 20.15**	**$ 21.41**	**$ 20.09**	**$ 20.49**	**$ 27.36**	**$ 33.62**	**$ 34.96**	**$ 23.76**	**$ 21.87**	**$ 20.29**	**$ 18.69**	**$ 24.87**
	NPC Benefit of Net Metering Generation															
46	Total NPC Benefit of Net Metering Generation	Line 45 * Line 10	$	**$ 43,839**	**$ 63,810**	**$ 99,412**	**$ 104,988**	**$ 104,801**	**$ 180,527**	**$ 224,095**	**$ 224,877**	**$ 146,580**	**$ 123,389**	**$ 78,931**	**$ 41,953**	**$ 1,437,202**