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.

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[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.

[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

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[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

[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.

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[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

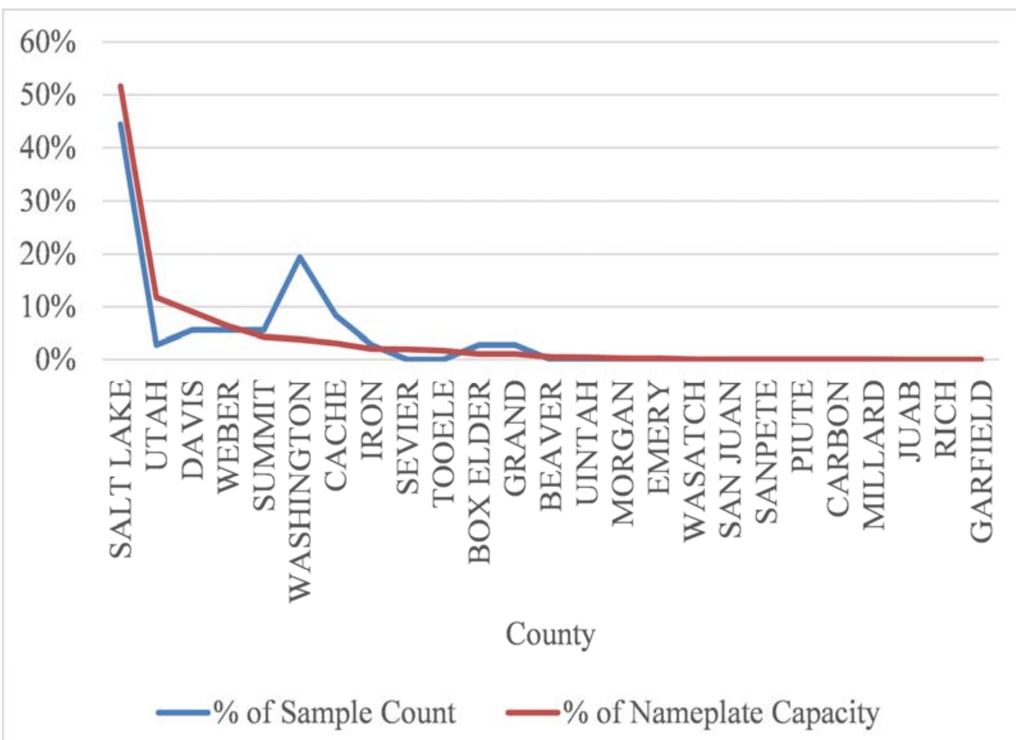
[56] Collins Direct Testimony, ll.792-848.

[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.

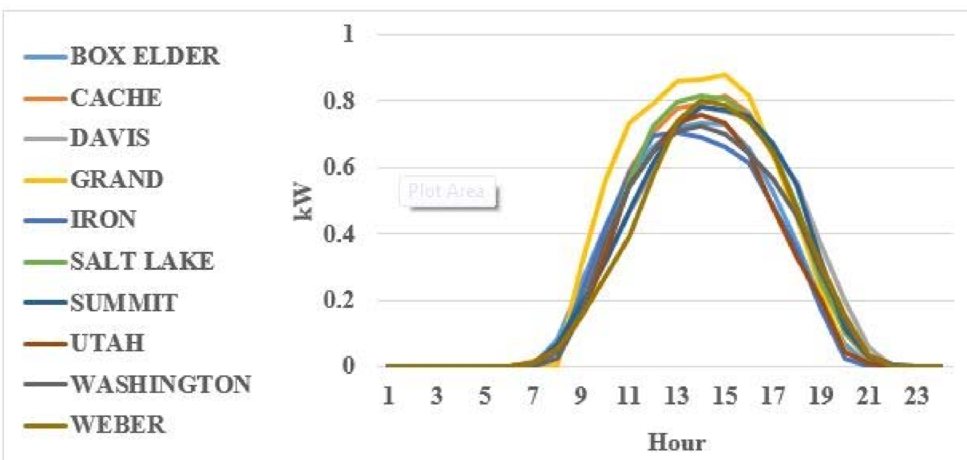
The Company's standardized production profile was developed using samples from various counties and weighting the data from those counties by interconnected capacity in each county. For those counties that have more significant interconnected capacity, the sample size is higher. For those counties with 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

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[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]

[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]

[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.

[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.

[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.