Before the
Public Service Commission of Utah

In The Matter of the Investigation of the)
Costs and Benefits of PacifiCorp's Net)
Metering Program)

Docket No. 14-035-114

Surebuttal Testimony of
Benjamin Norris

On The Topic of
The Benefit-Cost Framework for Net Energy Metering

On Behalf of
Utah Clean Energy, the Alliance for Solar Choice, and Sierra Club

September 29, 2015

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1. INTRODUCTION AND QUALIFICATIONS

Q. Please state your name, title, and employer.

A. My name is Ben Norris. I am Senior Consultant at Clean Power Research, located at 1541 Third Street, Napa, California.

Q. On whose behalf are you testifying in this case?

A. I am providing evidence on behalf of Utah Clean Energy, the Alliance for Solar Choice, (TASC), and Sierra Club (together the "Joint Parties").

Q. What is the purpose of your surrebuttal testimony?

A. The purpose of my surrebuttal testimony is to clarify the record in terms of calculating cost and benefit components under the Joint Parties' analytical framework. I seek to clarify that I have not proposed quantifying actual values for any cost or benefit component in this docket, pursuant to the Joint Parties' understanding that the purpose of this proceeding is to approve an analytical framework for subsequently evaluating the costs and benefits of net metering (to the utility system and all ratepayers).

Rather, the Joint Parties have proposed including categories of costs and benefits in an analytical framework, whose values are to be quantified in a subsequent proceeding. In my direct testimony, I described methods for quantifying the values associated with those categories of costs and benefits, and in my rebuttal testimony I responded to certain components proposals presented by the Division of Public Utilities (the Division) and Rocky Mountain Power (RMP), to illustrate why they were inferior to the analytical framework proposed by the Joint Parties.

In my surrebuttal testimony, I will clarify for the Commission the appropriate method and justification for calculating specific net metering cost and benefit components and recommend that the Commission approve the analytical framework proposed by the Joint Parties. My surrebuttal testimony addresses a narrow set of issues that I view as important in terms of clarifying the record. My lack of a response on a particular issue should not be construed as agreement.

2. SUMMARY OF FINDINGS AND RECOMMENDATIONS

Q. Please summarize your findings and recommendations.

A. The Joint Parties have not sought to quantify specific net metering benefits or costs in the current proceeding because such a task is not consistent with their understanding of the purpose of the current docket. Rather, my testimony has described *methods* for quantifying values associated specifically with attributes of distributed generation, without attempting to prove or disprove specific values or quantification.

Distributed resources have distinct attributes whose valuation methods are distinct from those applicable to utility-scale or QF resources. The methods I have proposed for valuing the benefits and costs of distributed resources are specifically tailored for valuing the unique attributes of distributed resources.

3. SELECTED RESPONSES

Single system proxy versus fleet proxy

Q. Your method for determining avoided energy and capacity values was criticized for being too complicated, as it is based on aggregating the solar output of hundreds of distributed solar resources, as opposed to the Commission-approved avoided cost pricing method, which is based on deferring a single proxy solar resource.[1] Please explain why you recommend using aggregated data from modeled distributed solar resources in your valuation method.

A. In my direct testimony, I recommended the use of a fleet production shape consisting of the aggregated output of many systems in order to represent the diversity of the actual fleet of distributed solar in terms of both geographical spread and differences in design configuration (tilt and azimuth angles).

Q. Mr. Clements states in his rebuttal testimony that the collection of such data is "administratively burdensome" and that the Company would not have a means of acquiring the data.[2] Do you agree?

A. No. Clean Power Research (CPR) routinely models large fleets of solar resources and hourly fleet production datasets. CPR just completed a modeling exercise covering the approximately 200,000 individual solar resources in the three IOU service territories in the load balancing area of the California ISO for 2010 to 2014. We have modeled fleet profiles for Duke Energy in its DEC/DEP (Carolinas, with 2,288 resources), DEF

[1] Paul H. Clements Rebuttal Testimony, pages 7-8, lines 157-70.
[2] Paul H. Clements Rebuttal Testimony, page 8, line 165.

(Florida, with 10,050 resources), and DEI (Indiana, with 2,562 resources) regions. We have modeled fleets for various solar valuations studies comprising thousands of systems. All of these fleet simulations have been time synchronized with system loads, distribution loads, or both. Thus, the prospect of doing "several hundred" systems in Utah does not seem to be particularly burdensome.

Q. Mr. Clements also states that the fleet simulation approach "is not necessary to accurately determine avoided energy costs."[3] Do you agree?

A. No, using a single system is not sufficient. To my knowledge, using a single system to determine the avoided energy costs of a fleet of distributed solar resources has never been done, so it is difficult for me to estimate the loss in accuracy that occurs by limiting the analysis to a single proxy system. I would expect, in agreement with Mr. Clemens, that the difference in avoided energy costs (expressed in dollars per unit of production) would probably not be significantly different between the two approaches. On the other hand, I would expect that the avoided capacity costs would be significantly different.

According to RMP's response to Utah Clean Energy's (UCE) data request (4.4b) there are 4,773 net metered systems in Utah. In evaluating their costs and benefits to the grid, it would seem unnecessary to introduce an unknown amount of error into such an analysis by assuming *a priori* that a single system with a single design orientation in a single location would result in a representative valuation for all 4,773 systems.

[3] Paul H. Clements Rebuttal Testimony, page 8, line 163.

Figure 1, below, provides an illustrative example of the importance of considering the combined effect of multiple systems. This figure is the modeled solar production (using CPR's SolarAnywhere data and system modeling capabilities) of two systems with identical unit power ratings in Salt Lake City on the day of the July 2014 system coincident peak. The first system is fixed, south-facing, with a tilt angle of 27 degrees (corresponding to the orientation selected for the single proxy system used by RMP's consultant referenced in the rebuttal testimony of Mr. Clements[4]). The second system is fixed, east-facing, with the same tilt angle.

According to its response to UCE data request 4.2a, RMP indicated that during this month the system coincident peak occurred on July 14 at the hour ending 16, Pacific Prevailing Time. This corresponds to the hour beginning at 3:00 pm and ending at 4:00 pm, Mountain Standard Time, as used in the figure. For the south-facing system, the average power output during this hour is 72.9% of its AC rating, but for the east-facing system, the output is 46.9%. Therefore, to assume that the south-facing system adequately represents the peak load reduction capability of the east-facing system is to introduce an error of over 50 percent. Each configuration would have an associated error as illustrated here, and additional error would be introduced by assuming that the Salt Lake City irradiance matches the irradiance throughout the state.

[4] Paul H. Clements Rebuttal Testimony, page 18, footnote 9.

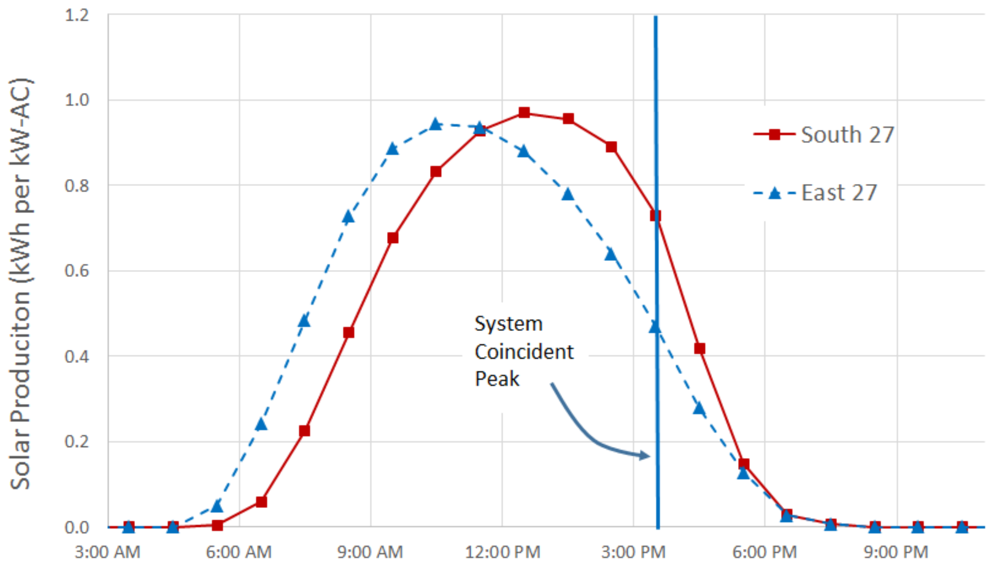

Figure 1. Solar production of two systems (July 14, 2014, Salt Lake City, MST)

Q. Mr. Clements recommends the use of a Commission approved method used to generate Schedule 38.[5] Do you agree with this method?

A. No, I do not. As shown in the illustrative example above, a single system does not represent the output of other systems and can introduce errors in the analysis. Furthermore, a cost and benefit study is not done for the purpose of determining payments to qualifying facilities and should not be bound by Commission orders related to such payments. In addition, the analysis used in the utility scale proxy for Schedule 38 does not include the effects of losses avoided by distributed resources, but a cost and benefit study of distributed, net metering resources should account for this difference.

[5] Paul H. Clements Rebuttal Testimony, page 9, lines 183-86.

<u>Avoided transmission costs</u>

Q. Mr. Clements argues that avoided transmission costs should be calculated on a case-by-case basis by identifying QF project-specific net benefits to planned Company transmission facilities.[6] Do you agree?

A. No, this type of calculation is not necessary. Mr. Clements based his recommendation on the reasoning that to date, no single QF facility has demonstrated avoidance or deferral of transmission facilities. However, the NEM cost and benefit study would not be bound by the same QF avoided costs order. Additionally, in such a (cost-benefit) study, it is the aggregate effect of all net metering resources that would be applicable. It would not be practical to perform a separate cost and benefit study for each individual net metering resource. Rather, I believe that it would be more sensible to consider all net metered resources in the aggregate and determine whether or not these combined resources would have a corresponding transmission benefit over their service lives.

<u>Increased distribution system costs</u>

Q. RMP argues that the distribution system is impacted by net metering in a way that is likely to increase distribution system costs.[7] What is your response?

A. It is reasonable to expect, based on the arguments advanced by Mr. Clements and Mr. Marx, that there may be future distribution costs incurred in order to support net metered systems. However, only costs paid by the utility or the other ratepayers should be

[6] Paul H. Clements Rebuttal Testimony, page 10, line 205-08.
[7] Douglas L. Marx Rebuttal Testimony, page 2, line 39; *see also* Paul H. Clements Rebuttal Testimony, page 11, lines 243-45.

included in cost-benefit analysis, not those paid by the net metering customers themselves.

In its response to UCE data request 4.4f, RMP indicates that "the current Utah Administrative Code regarding interconnection places the cost of modifications to the utility distribution system" on the distribution customer. Therefore, since neither the utility nor the ratepayers incur these costs, they should not be included in a cost and benefit study that considers ratepayer impacts or utility system cost impacts.

Q. Are there circumstances where customer costs for the distribution system should be included?

A. If the cost and benefit study included a total resource cost (TRC) evaluation, which includes the costs paid by the net metering customer, then these costs should be included, but only in the TRC portion of the study. However, no party recommended the TRC test as a basis for the cost-benefit framework, and therefore there is no reason to include those costs.

Q. What distribution system costs did Mr. Marx identify?

A. There were three categories of distribution costs considered in Mr. Marx's rebuttal:

- Facilities costs (i.e., those associated with the service entrance to the net metering customer)[8]

[8] Douglas L. Marx Rebuttal Testimony, page 4, lines 73-77.

- Local neighborhood costs[9]
- Bi-directional equipment costs[10]

I will address each of these. First, as explained in RMP's response to our data request (4.4), only four out of the installed 4,773 systems in Utah actually required facilities modifications in order to accommodate solar, and the total cost is about $1 per kW-DC. At a total installed cost of about $4,000 per kW-DC, the cost of facilities modifications to the average solar customer would therefore be only about 0.025% of the total system cost. In a TRC evaluation, I would recommend that the current costs ($1 per kW-DC) be used as the basis of future costs because these costs are independent of solar penetration level (because they are customer-specific). In other words, these costs do not increase on a per kW basis with increasing solar penetration.

RMP further identified "local neighborhood distribution costs" as another cost impact.[11] However in its response to our data request (4.5a), RMP indicates that, to date, no such costs have been incurred. It is not clear when in the future distributed solar would result in such expenditures. However, if it can be shown that such local neighborhood distribution costs would be incurred at some point in the future, then only those costs borne by the utility and ratepayers could legitimately be included in a cost and benefit study.

[9] Douglas L. Marx Rebuttal Testimony, pages 4-5, lines 80-99.
[10] Douglas L. Marx Rebuttal Testimony, pages 6-7, lines 115-48
[11] Douglas L. Marx Rebuttal Testimony, page 5, line 94.

However, at present, these costs are subject to significant uncertainty since they have never occurred, and we therefore lack a means of determining them. More importantly, RMP indicates that these costs would not be paid by the utility or ratepayers (similar to facility costs), but by the solar customer. For this reason, these costs should not be included in the cost and benefit study (except for a TRC analysis). I believe that additional study would be required to accurately assess future costs in relation to projected penetration levels.

RMP further identified that bi-directional equipment would be an additional cost incurred as necessary to support net metering systems.[12] However, in its response to our data request (4.6c), RMP indicates that no bidirectional equipment has ever been installed. By the same reasoning above related to local neighborhood costs, then, these costs are paid by net metering customers and not by RMP or the ratepayers. Therefore, they should be excluded from a cost and benefit study (except in the case of a TRC evaluation).

<u>Avoided distribution costs</u>

Q. Mr. Clements recommends excluding avoided distribution costs on the basis that the distribution system is being used to move solar excess energy.[13] What is your response?

A. I agree that a portion of the distribution system is used, but not all of it. For example, since RMP does not require the use of bi-directional protective devices (see above), it is reasonable to assume that excess solar generation is not produced in sufficient quantities

[12] Douglas L. Marx Rebuttal Testimony, pages 6-7, lines 115-48.
[13] Paul H. Clements Rebuttal Testimony, page 11, line 243-445.

to result in significant backflow into the system. There is certainly no evidence provided that backflow reaches the distribution substations. Therefore, it is logical to conclude that only a portion of the lines are used, not all of the lines, and certainly not the substations.

Following Mr. Clements' argument, then, since the solar excess generation does not use the substations, then avoided substation costs should be included in the analysis. RMP tracks the capital costs of substations separately from conductors, poles, and other equipment, so it would be relatively easy to include these in the cost-benefit analysis. I recommend that the distribution substation costs be considered as possible avoided costs, using the methods described in my testimony. With additional data, it may be possible for parties to demonstrate that additional distribution facility costs are avoided by virtue of the net metering program. The avoided distribution cost category, however, should be included in the cost-benefit framework as a broad category, leaving open the possibility of costs other than distribution substations being impacted.

<u>Solar coincidence with peak load</u>

Q. Mr. Marx suggests that in Utah peak load occurs during the waning hours of solar production.[14] How do you respond?

A. Mr. Marx's description of the peak load may be accurate, particularly on circuits in which there is a high proportion of residential load. However, this assumption should be verified. My direct testimony presents a method by which solar coincidence should be calculated and used in the estimation of avoided costs. I believe that this method should

[14] Douglas Marx Rebuttal Testimony, page 3, line 54.

be used, or a similar method, which *quantifies* load reduction, rather than simply assuming that solar production is zero during the peak on all circuits.

Q. Mr. Clements, in his rebuttal, offers a quantitative approach (see Table 1) that attempts to address the relationship to solar production and peak load.[15] What is your opinion of this approach?

A. The referenced consultant study is flawed for two reasons. First, the solar data used ("TMY3, Salt Lake City") was *not measured at the same time as the load*. For example, the July 2014 coincident peak load occurred in July 2014, but a simple examination of the public TMY3 resource data shows that the underlying solar data used in the modeling was measured *in July 1991*. This problem could be corrected by either (1) using load data from 1991 or (2) using solar data from 2014, as I did in the above analysis of the two distributed solar systems.

Second, and more importantly, Mr. Clements draws conclusions from the Table 1 data based on solar production during the *monthly system coincident peaks*. He notes, for example, that during a number of monthly system coincident peaks the solar production is zero. While this may be true, it is not a result that would be applicable in the analysis of avoided distribution capital costs. This is because engineering decisions to increase distribution capacity, such as distribution substation capacity, are not made by considering loads during the times of the twelve coincident peaks per year. Rather, they are made on the basis of the comparison of peak annual loads to substation capabilities.

[15] Paul H. Clements Rebuttal Testimony, page 19, Table 1.

For example, if the distribution peak occurred on July 14 of a given year, and if substation loads during the peak hour measured 100% of available capacity, then the conclusion would be that the substation has reached its capacity limit. If during a previous monthly coincident peak in January the substation load were only 50% of its rated capability, it would not matter. Only the load during the annual peak is relevant. The loads during other periods are not relevant to determining the likelihood of transformer overload. For the same reason, solar production during the January system coincident peak would not be a relevant measure of its effectiveness in avoiding distribution costs.

In UCE's data request we asked "please provide the day and hour in which the system peak occurred in each year." This data was not provided (monthly peaks were provided), so we do not know which of the twelve monthly system coincident peak times corresponds to the annual peak. However, by way of example, suppose that the annual peak in 2014 was in July. Then, according to the consultant's study, the resource was producing 54% of its rated output during the annual peak.[16]

Next, suppose 1 MW of solar capacity (aggregated over many redundant resources), were electrically connected to a substation with a maximum rating of 10 MW, and that the load was measured at 9.5 MW. This means that the solar resource would be preventing the substation from overloading because the combined resource would be providing 540 kW,

[16] Note that the 54% result contradicts the SolarAnywhere modeling result of 72.9% as described above. There are several possible reasons for this discrepancy, including the fact that the consultant used solar data from 1991, rather than 2014, as described above. There are probably differences in system rating conventions. However, the source of discrepancy is not investigated here. The argument that follows is merely illustrative, therefore, and assumes that the 54% result is correct.

or nearly 600 kW when considering avoided losses. If the solar generation were not present, then the load would be 9.5 + 0.6 = 10.1 MW—in excess of its rated capacity. It does not matter what the solar resources are producing in January.

4. RECOMMENDATIONS

Q. Please summarize your recommendations.

A. I continue to stand by the recommendations provided in my direct and rebuttal testimony. I recommend that the Commission approve the analytical framework proposed by the Joint Parties.

Q. Does this conclude your rebuttal testimony?

A. Yes, it does.