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

Rebuttal 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 8, 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 the Sierra Club (together the "Joint Parties").

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my rebuttal testimony is to respond to certain components of the direct testimonies presented by the Division of Public Utilities (the Division) and Rocky Mountain Power (RMP). Specifically, I address the methodological components of the analytical frameworks proposed by the Division and RMP.

2. SUMMARY OF FINDINGS AND RECOMMENDATIONS

Q. Please summarize your findings and recommendations.

A. The cost of service framework described by Robert Davis and recommended by the Division is silent on several critical evaluation details. As such, it is incomplete and cannot be relied upon as an analytical framework for evaluating the costs and benefits of net energy metering (NEM). The Division's testimony also addresses some of the technical complexities of distributed generation in factually incorrect ways. My testimony addresses these inaccuracies.

The framework proposed by RMP is problematic because the definition of costs and the definition benefits are contradictory. The testimony also contains a key inaccurate statement that generation provided on the transmission system provides the same benefits as generation behind the meter. My testimony explains why this is not correct.

I recommend that these framework and analytical issues be overcome by using the framework presented by the Joint Parties.

3. REBUTTAL OF DIVISION OF PUBLIC UTILITIES TESTIMONY

Responses to the Division's Cost of Service Framework

Q. What aspects of the Division's proposal for a cost-benefit analysis will you address in your rebuttal testimony?

A. My colleague Tim Woolf provides a review and critique of the Division's proposal for an analytical framework based on a cost of service study. I will address specific components of the Division's proposal, including the Division's silence on key evaluation details.

Q. How does the Division propose to account for the costs of generation, transmission and distribution investments that are avoided by distributed generation in its cost of service framework?

A. The Division does not specifically account for the generation, transmission, and distribution costs that distributed generation can avoid, but rather states, "Any other pertinent costs and benefits could be considered outside the cost of service model in some fashion, similar to the way avoided capacity costs are defined outside of the Generation and Regulation Initiative Decision (GRID) model."[1]

Thus it may be inferred that the Division's proposed cost of service framework includes the benefits of avoided generation capacity. However, the framework does not describe how the benefits of costs avoided are actually incorporated or accounted for. Nor does it describe how savings from future avoided transmission or distribution investments are incorporated within a cost of service framework.

Q. The Division recommends that two studies be prepared: one that does not account for distributed generation and one that does, and that a comparison of the two would indicate the benefits.[2] Does this proposed method fairly account for the benefits?

A. No, it does not. The Division states, "A comparison of the results from the two studies would indicate the benefits from net metering to Utah and to the specific customer or rate class."[3] Such a framework would divide benefits resulting from Utah-based solar resources among both Utah and non-Utah customers. As a result, the framework effectively tracks only a fraction of the total benefits.

For example, if distributed solar generation located in Utah can be shown to reduce required *system* generation capacity in future years, then the proposed cost of service framework would recognize savings to Utah in an amount less than the total savings to the system. The remaining benefit would be ignored. I believe that the full costs and

[1] Davis Direct Testimony, page 6, lines 94-98.
[2] Davis Direct Testimony, page 7, lines 106-17.
[3] Davis Direct Testimony, page 7, lines 116-18.

benefits should be included based on the assumption that the Commission is able to determine and implement a fair and prudent cost allocation method across state jurisdictions.

Q. Does the Division's proposal correctly account for loss savings?

A. No, the proposed framework is also silent on the treatment of loss savings. By comparing the two studies (without net metering and with net metering), it appears that the intent is to calculate the incremental impact of net metered resources. Yet, a key aspect of such a study would be to quantify avoided marginal losses in the transmission and distribution lines, and this is not described.

Avoided losses under the Commission's analytical framework should be calculated hourly, and they should be calculated on a marginal basis. The marginal avoided losses are the difference in hourly losses between the case without the net metered resource, and the case with the net metered resource. For example, if a resource were to produce 1 kW of power during an hour in which customer load on a circuit is 1000 kW, then the avoided losses would be the calculated losses at 1000 kW of customer load minus the calculated losses at 999 kW of load.

Q. Does the Division's proposal address avoided risk?

A. No. As outlined in my direct testimony, there are several sources of risk which distributed solar either eliminates or mitigates. The Division's proposed framework only considers current costs and current cost allocations, and is therefore unable to incorporate the benefit of avoided risk. These risks are quantifiable and should be incorporated in the final framework.

Complexities of Distributed Generation

Q. The Division's testimony includes a statement that distributed solar photovoltaics, as an intermittent resource, "results in relatively unstable loads."[4] What is your response?

A. This is not correct. Neither loads nor their stability are affected by solar generation. Customers control loads by turning them on and off. They are not controlled by changes in generation sources. For example, an electric motor will draw the same current whether the marginal plant is coal, gas, wind, or solar. It will not become unstable by changing generation sources.

Q. The Division's testimony includes a statement that distributed solar results in "little measurable reduction in peak load."[5] What is your response?

A. This is not an accurate statement. On the contrary, in late 2013, I performed on behalf of Utah Clean Energy an hourly analysis for 2012 for a fixed, south-facing solar resource with a 40-degree tilt angle located in Salt Lake City.[6] This resource was modeled using Clean Power Research solar irradiance and ambient temperature taken from a 10 km x 10 km measurement grid, located in Salt Lake City. Hourly solar output was then compared with time-aligned hourly aggregate load data provided by Rocky Mountain Power.[7]

[4] Davis Direct Testimony, page 9, line 144.
[5] Davis Direct Testimony, page 9, lines 144-45.
[6] A report of this study was filed in Docket No. 13-035-184 as UCE Exhibit 2.1 DT (*Value of Solar in Utah*, prepared for Utah Clean Energy by Clean Power Research (January 2014)).
[7] *Id.* at ii.

Two metrics were used to quantify peak load reduction. The first was to calculate the "effective load carrying capability (ELCC)." The ELCC is the corresponding rating of a perfectly operating baseload plant having the same loss of load probability as the PV resource.[8] The ELCC for the solar resource was found to be 53% of the maximum AC output of the resource. When the effect of offset marginal hourly transmission and distribution losses were included in the calculation, the ELCC was 66%.[9]

The second metric was the "peak load reduction (PLR)." The PLR is the direct reduction in the peak annual distribution load during the maximum load hour of the year.[10] This was found to be 70% of the maximum AC output of the solar resource. When the avoided distribution losses were included (ignoring avoided transmission losses), the resource effectively reduced the peak annual distribution load by 87% of its maximum AC output.[11]

[8] *Id.* at 7.
[9] *Id.* at 9.
[10] *Id.* at 7-8.
[11] *Id.*

A more comprehensive technical analysis would incorporate other orientations, locations, and years. However, it is simply not true that distributed solar has little measurable effect on peak load in Utah.

A study which is designed to evaluate the costs and benefits of distributed solar would incorporate measures such as the ELCC and PLR into its evaluation in order to correctly account for the degree to which solar and load are matched. Load match factors are described in my direct testimony.

Q. The Division's testimony includes a statement that, with distributed generation, "the utility has to be concerned about system reliability" and "balancing of the system."[12] What is your response?

A. While this is a true statement, the same would be true if DG were not present. The utility would still have to be concerned about system reliability and about balancing of the system. No evidence is provided showing how DG either increases or decreases the concern or the cost. I believe that it would be reasonable to include integration costs insofar as they are significant and can be calculated based upon available representative data.

Q. The Division alleges that distributed generation causes the utility to be more concerned about "unintentional islanding."[13] What is your response?

A. The possibility of islanding has been studied over many years by utility engineers, inverter manufacturers, and others. The result is a set of interconnection standards (IEEE-

[12] Davis Direct Testimony, page 9, lines 145-46.
[13] Davis Direct Testimony, page 9, line 146.

1541, UL-1741), which address the issue. Rocky Mountain Power requires inverters to adhere to these standards prior to approval for interconnection. Every other jurisdiction in the U.S. has similar requirements. No evidence has been presented indicating that an unintentional islanding concern exists. Furthermore, no evidence has been presented showing that an unintentional island has ever occurred, within or without Utah, despite the existence of 20,000 MW of solar capacity on the nation's electrical grids.

Q. The Division states, "as higher DG penetrations are reached, utilities may begin to see effects such as additional wear and tear on distribution system equipment, needs for substation upgrades, re-conductoring of power lines, added safety equipment for systems and personnel and Front Office Transactions (FOTs) to keep the system balanced."[14] What is your response?

A. To support these claims, the Division references a report by the National Renewable Energy Laboratory. The referenced study describes a value impact of only 2.4 percent under a 35 percent penetration scenario. By comparison, Utah only has a 0.3 percent penetration. Thus, the scenario considered in the study was 117 times the solar penetration level of Utah. It therefore does not appear that the value impact is significant at current penetration levels. It will be many years before Utah penetration levels increase by a factor of 117, so the cost impacts may be considered negligible for the foreseeable future.

Furthermore, the testimony appears to have the costs and benefits reversed in the case of needs for substation upgrades and re-conductoring. Depending upon the match between

[14] Davis Direct Testimony, page 9, lines 148-51.

solar production and load (as measured, for example, by the PLR), it may follow that the need for additional substation and line capacity would be reduced, not increased, and should appear as a benefit in the framework, not a cost.

Q. The Division states that distributed generation can change the efficiencies of thermal power plants because of different usage and cycling profiles.[15] What is your response?

A. This is a correct statement. The annual cost impact of this effect would be indicated in the results of the proposed framework outlined in the testimony of the Joint Parties. However, the efficiencies of thermal power plants depend on a range of factors including load levels, the specific units on line in a given hour, their part-load efficiency characteristics, and the amount of distributed generation in that hour. Under some conditions, distributed generation could actually cause an increase in thermal unit efficiency.

Q. The Division states that it has data that does not "indicate meaningful offsets to system peak loads."[16] What is your response?

A. The evidence offered by the Division is a 2010 study conducted by Rocky Mountain Power, and the Division has broadened the conclusion to include monthly coincident peak, annual system peak, and class peak.[17] Unfortunately, the Rocky Mountain Power study is flawed in many respects for the reasons described below.

[15] Davis Direct Testimony, page 9, lines 153-55.
[16] Davis Direct Testimony, page 11, line 189.
[17] Davis Direct Testimony, page 11, lines 190-93.

- The solar modeling incorporated in the study is not in line with standard solar modeling practices and does not incorporate measured irradiance data (or measured PV power data). No attempt to correlate modeled solar output to measured solar production data was attempted. This is problematic because theoretical models that are not verified against physical systems are subject to unknown amounts of error.
- The analysis is based on weather indices averaged with a temporal resolution of one month. The electrical circuit load against which solar production was compared, by contrast, has a temporal resolution of one hour. Since the weather input data resolution was monthly, comparisons with hourly circuit loads are not valid, any more than if monthly averages of circuit loads were to be used against hourly solar measurements. The study claims to produce daily insolation data from monthly input values, and it is an even further stretch to believe that hourly production can be calculated from monthly cloud cover data.
- The effect of PV system tilt angles and azimuth angles were not calculated correctly. For example, the irradiance data were not broken down into components (e.g., direct normal irradiance, global horizontal irradiance, and diffuse horizontal irradiance) from which plane-of-array irradiance (irradiance per unit area of array surface) could be calculated using standard solar modeling techniques.
- The accuracy of the results is only as good as the accuracy of the input data. The input data in this study, however, was based on only three observed sky conditions (“clear, cloudy, partly cloudy”). In an actual study, irradiance would

typically be measured with a resolution of a few percent instead of these three broad classifications. The results are therefore no more accurate than if the electric load was characterized as “low, medium, and high” instead of using actual measured electrical power.

- The study refers to the distribution circuit peak on August 2, 2010, yet the underlying measured weather data did not come from this day. Therefore, it is analytically incorrect to draw conclusions about solar performance on this peak day.

Q. What conclusions or recommendations do you draw from these critiques of this study?

A. Based on the above concerns, I do not believe that any conclusions should be drawn using this study as a basis. Rather, an actual study would be based either on measured solar production or hourly modeled data. It should also include a wide range of locations and system design orientations to resemble the actual “fleet” of solar resources. My recommendations for accomplishing this are found in my direct testimony.

Q. Regarding the study, the Division stated, “The Company determined that by the time the system was reaching its peak load, the solar generation on the circuit under study was producing less than seven percent of the needed system peak load requirement,”[18] and attached an hourly chart to show the 7% match. What is your response?

[18] Davis Direct Testimony, page 11, lines 196-99.

A. I disagree with the conclusions based on the following points:

- The hourly solar production profile is flawed for the several reasons described above.

- The statement draws an arbitrary conclusion that a 7% reduction in peak load is not a “meaningful offset” to system peak loads. While the 7% result is incorrect, it is not clear why the Division would not consider it to be meaningful. By this reasoning the Gadsby generating facility in Salt Lake City, able to support only 4% of the system coincident peak, would likewise not provide a “meaningful offset” to peak load, yet if this plant were removed from service, the system would be less reliable.

- The study considered only a single distribution circuit, Northeast Circuit 16, rather than data aggregated for the utility as a whole. The selected circuit has a very high proportion of residential customers as indicated by the land use data. These types of circuits peak later in the day than the system as a whole. Consequently, the study does not use a representative electric load profile, and it is insufficient to draw conclusions about other circuits having different characteristics. Northeast Circuit 16 is certainly not representative of Utah as a whole, nor is it representative of the multistate PacifiCorp system.

4. REBUTTAL OF ROCKY MOUNTAIN POWER TESTIMONY

Analytical Framework—Costs Components

Q. Please describe the costs components contained within Rocky Mountain Power's Analytical Framework Proposal.

A. In the testimony of Paul Clements, Rocky Mountain Power identifies the NEM program cost to non-participants, essentially, as the lost revenue due to solar production behind the meter. This includes two types of production: (1) energy that is generated and consumed on-site; and (2) energy that is exported to the grid in excess of consumption.[19]

Q. What is your response to RMP's framework cost components?

A. Both types of energy may indeed be quantified in dollar terms based on retail rates for reasons described by Mr. Clements. However, the characterization of this energy as a cost to the utility is not correct.

Mr. Clements describes in his testimony the method by which costs accrue to utility customers. In his description of the process, he explains that rate case proceedings establish revenue requirements, and that revenue requirements reflect "the costs associated with providing service to customers," such as generation, wholesale power purchases, and so on.[20]

[19] Clements Direct Testimony, page 10, lines 223-33.
[20] Clements Direct Testimony, page 9, lines 205-06.

The electricity generated by NEM customers does not fall into this category. The credits earned by NEM customers, for example, do not increase revenue requirements. For this reason, they are not costs which must be recovered by the Company.

Instead, electricity generated by NEM customers results in reduced revenue to the Company. There are many causes of reduced revenue, including efficiency measures, cooler weather years, loss of customers in economic downturns, and electricity theft. In Utah, none of these causes are considered costs to be added to revenue requirements. Instead, they are handled through the normal ratemaking process.

This is not to say that NEM generation does not result in costs. For example, the cost of metering could increase or the cost of voltage regulation could increase. In these cases, the Company would incur costs and rates would have to be designed to provide for their recovery.

I conclude that lost revenue should not be included as a cost when evaluating the costs and benefits of NEM. I recommend the framework proposed by the joint parties which does not depend on the inclusion of lost revenue as a utility cost.

Analytical Framework—Benefits Components

Q. Do you agree with the approach to benefits contained within Rocky Mountain Power's Analytical Framework Proposal?

A. RMP's testimony on benefits is not parallel with its description of costs for the following reason. In the costs description, the testimony includes both types of energy: (1) energy that is generated and consumed on-site; and (2) energy that is exported to the grid in excess of consumption. Yet the benefits that would be quantified according to the testimony of Mr. Clemens would be limited to only the customer generation provided to the Company as excess generation.[21]

To address this mismatch, in the remainder of my testimony, I assume that the costs and benefits of all NEM generation (not just the net exported energy) is the subject of the cost-benefit evaluation.

Q. In his testimony, Mr. Clemens states the following: "A solar panel or other generation resource will provide the same generation benefit to the system whether it is used by a customer behind their meter in a net metering configuration or used by the Company through a power purchase agreement or as part of a Company-owned resource."[22] What is your response?

A. This statement contradicts his previous testimony that benefits accrue to customers through "reductions in in the Company's overall revenue requirement," the first of three identified sources of benefits.[23] Energy produced by distributed generation resources does, in fact, reduce revenue requirements relative to energy obtained through power purchase agreements or Company-owned resources. Therefore, the benefits are not the same and Mr. Clements' statement that distributed solar provides the same generation benefit as any "other generation resource" is not correct.

The differences in revenue requirements between a distributed solar resource and other generation resources are based on the following considerations.

[21] Clements Direct Testimony, page 14, lines 305-11.
[22] Clements Direct Testimony, page 14, lines 315-18.
[23] Clements Direct Testimony, page 11, lines 239-40.

First, NEM generation occurs adjacent to the point of consumption. In order to serve load through power purchase agreements or Company-owned resources, more energy would have to be purchased or generated than would be produced by the NEM system. This is because some of the energy purchased or generated by the Company is lost in transmission lines, substation transformers, and distribution lines. By avoiding such losses, the required amount of energy to serve a load from distributed generation is less than the amount of energy from central, transmission-connected resources. This lowers revenue requirements.

Second, avoided losses also play a role in the capacity benefit of distributed solar resources. For example, if 10 percent of energy is lost between the point of generation and the customer, then a fleet of distributed generation resources with an aggregate rating of 100 MW would provide the same benefit as a central generation resource of 100/(1-0.1) = 111 MW. So, it is incorrect to say that distributed generation provides the same benefit as the central resource.

Third, distributed generation will reduce the amount of reserve capacity required by the Company, reducing revenue requirements. Reserve capacity must be procured by the Company in amounts necessary to ensure system reliability. Distributed generation effectively reduces the load at the meter and the load at the distribution substation.

Finally, Mr. Clements' testimony does not cover distribution benefits, namely, the potential to reduce distribution capital costs due to reduced peak distribution loads. While generation resources connected to the transmission system require substation capacity in order to deliver electrical energy to the loads, distributed generation does not. This is a key difference between these distributed resources and their utility-scale counterparts that are removed from load. To the extent that distributed generation is available at the time of the local load on distribution circuits, it would result in a reduction in future distribution capital investments, and thereby reduce revenue requirements.

Q. What is your response to Mr. Clemens' testimony stating that solar is not a dispatchable resource? [24]

A. Mr. Clemens is correct that solar resources are not dispatchable, and this should be taken into consideration when evaluating the energy benefits. Unit dispatch is primarily performed on the basis of marginal costs. Given that the marginal cost of solar is zero, it would be dispatched whenever it was available. The remaining units would then be dispatched, effectively, on the net load (load minus solar generation).

The energy benefit of distributed solar could therefore be determined by comparing revenue requirements without solar against revenue requirements with solar, using a dispatch model. Such a method would best quantify the actual cost savings provided by solar. For example, such a method would show that solar effectively displaces the most costly resources during the peak solar hours.

5. RECOMMENDATIONS

Q. Please summarize your recommendations.

A. I continue to stand by the recommendations provided in my direct testimony.

Q. Does this conclude your rebuttal testimony?

A. Yes, it does.

[24] Clements Direct Testimony, page 14, note 7.