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 Tim Woolf

On the Topic of
Net Metering Tariffs

On Behalf of
Utah Clean Energy

July 25, 2017

Table of Contents

1. INTRODUCTION AND QUALIFICATIONS

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

A. My name is Tim Woolf. I am a Vice President at Synapse Energy Economics, located at 485 Massachusetts Avenue, Cambridge, MA 02139.

Q. Are you the same Tim Woolf that provided direct testimony in this docket?

A. Yes.

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

A. I am providing evidence on behalf of Utah Clean Energy.

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my rebuttal testimony is to respond to the direct testimonies of other intervenors in this docket. Much of my testimony is focused on the direct testimonies of the Office of Consumer Services (the Office) and the Division of Public Utilities (Division).

2. SUMMARY

Q. Please summarize the issues that you address in your rebuttal testimony.

A. In my rebuttal testimony, I respond to the following findings and recommendations of other intervenors in this docket:

- Whether the current net metering program's benefits exceed its costs.
- Whether there is an urgent need to address cost-shifting in this docket.
- How to address cost-shifting from distributed generation (DG), including:

- Whether establishing a separate rate class for DG customers is an appropriate way to address cost-shifting concerns.
- Whether applying a demand charge to DG customers is an appropriate way to address cost-shifting concerns.
- Whether modifying the credits paid for excess generation for DG resources is an appropriate way to address cost-shifting concerns.
- Whether and how to grandfather distributed generation customers when new DG credit mechanisms or values are implemented.

Q. Please summarize your recommendations.

A. Nothing in the direct testimony of other intervenors causes me to modify my original recommendation that the Commission reject RMP's proposed net metering compensation mechanism. The Company's proposal (a) is unnecessary for addressing cost-shifting at this time; (b) violates several key ratemaking principles; and (c) will have a chilling effect on the development of DG in Utah.

Nonetheless, I recognize that continuation of net metering combined with rapid growth in DG resources might, at some point in the future, result in undesirable levels of cost-shifting. Therefore, I support the recommendation of the Office and the Division that the Commission consider alternatives to full net metering, particularly the recommendation of the Office to alter the credit for excess generation from DG. This one modification to the crediting mechanism can sufficiently mitigate cost-shifting and avoid the need for more drastic and problematic modifications, such as creating a new customer class or imposing demand charges on DG customers. Such changes should be implemented at the time of the next general rate case,[1] or in a separate proceeding to set alternative bill credits for excess generation.

Finally, I recommend that the Commission establish alternative compensation levels for excess generation that are predictable and of sufficient duration to allow customers to project long-term savings based on reasonable assumptions. Specifically, I recommend that all existing net metering customers and those who install DG prior to the conclusion of the next RMP rate case (or export compensation docket) continue to receive net metering compensation for at least 20 years after their DG installation date. For subsequent DG customers, I recommend that these customers be grouped into tranches, with a different excess generation compensation rate set for each tranche. Once enrolled in a tranche, a customer would receive the same compensation rate for excess generation for at least 15 years.

3. COSTS AND BENEFITS OF NET METERING

Q. The Office and the Division conclude that the Company's cost of service analysis is generally consistent with the Commission's November 2015 order.[2] Do you agree?

A. No. While the Company developed a counter-factual cost of service (CFCOS) study and an actual cost of service (ACOS) study consistent with the Commission's order, the

[1] Beck Direct Testimony at 18, and Powell Direct Testimony at 6.

[2] Utah Public Service Commission, In the Matter of the Investigation of the Costs and Benefits of PacifiCorp's Net Metering Program, Docket No. 14-035-114, Order, November 10, 2015. As stated by the Commission on page 10 of the order, "Comparing the cost of service for the existing classes under the ACOS and CFCOS will show both the total and average cost impact on the existing classes, and this information will be valuable in assessing a just and reasonable rate structure."

Company did not present a direct comparison of these two studies. Instead, the Company added bill credits onto the results of the cost of service studies.

Adding bill credits as a cost of net metering is contrary to the Commission's order that "The categories of costs in both studies should generally be consistent with those PacifiCorp employs in preparing cost of service studies for ratemaking purposes."[3] Bill credits are not a cost of service: they do not represent a new incremental cost of providing service to customers, and they do not increase revenue requirements. Bill credits simply represent revenue that the Company does not collect, which is fundamentally different from incremental costs that are included in cost of service studies.

Q. Are you suggesting that bill credits from distributed generation resources are irrelevant?

A. No. While bill credits do not represent a new cost to customers, they do provide information on the extent to which DG resources might result in cost-shifting among customers. The revenues that are not recovered from DG customers (as indicated by the bill credits) may need to be recovered from other customers, and may therefore result in cost-shifting. Therefore, bill credits should be included in cost-shifting analyses. But cost-shifting analyses are different from cost-benefit analyses, and it is necessary to distinguish between these two types of analyses.

[3] Utah Public Service Commission, *In the Matter of the Investigation of the Costs and Benefits of PacifiCorp's Net Metering Program*, Docket No. 14-035-114, Order, November 10, 2015, p. 13.

Q. Why is it necessary to distinguish between cost-benefit and cost-shifting analyses?

A. It is important to consider the results of *both* a cost-benefit analysis and a cost-shifting analysis when determining just and reasonable rates. If DG is expected to reduce the total costs to serve Utah customers, then it is important to ensure that DG compensation be set in a manner that will allow DG to continue to grow and provide such benefits. At the same time, however, if a cost-shifting analysis shows that costs are being disproportionately recovered from non-DG customers, then DG compensation rates should also be designed to mitigate unreasonable cost-shifting. In short, DG compensation rates should be designed to strike a balance between supporting DG (if it reduces total costs) and mitigating unreasonable cost shifting among customers.

Q. The Office and the Division agree with RMP that the costs of the current net metering mechanism outweigh the benefits.[4] Do you agree?

A. No. The Office and the Division are apparently relying upon RMPs' benefit-cost analysis to reach this conclusion. Thus, they are relying upon the Company's analysis that inappropriately adds bill credits on top of the cost of service results. As noted above, the bill credits should not be added on top of the cost of service results because they are not a new incremental cost of providing service to customers.

In fact, the Company's analysis shows that the ACOS case (including distributed generation) *reduces* revenue requirements for all classes by roughly $2.19 million, and

[4] Direct testimony of Michelle Beck, page 6, and Direct testimony of Artie Powell, page 4.

reduces revenue requirements for the residential class by roughly $1.32 million. Thus, the NEM program results in *lower* total costs to customers, not higher costs.

4. COST-SHIFTING AND WAYS TO ADDRESS IT

<u>Cost-Shifting</u>

Q. The Office claims that the "magnitude and urgency" of cost shifting has been overstated by RMP?[5] Do you agree?

A. Yes. The Company's analysis overstates cost-shifting in several ways. First, as noted by many intervenors in direct testimony, the one-year analysis period does not fully capture the benefits of distributed generation. The Division's witness Mr. Faryniarz contends that "it is likely that transmission, distribution, and environmental compliance avoided cost benefits [of DG] may not be able to be properly captured," due to the use of a "one-year historic test-period for [the] cost-benefit analyses."[6]

Second, the Company's analysis overstates the cost-shifting impacts of bill credits by assuming that all lost revenues will be collected from customers, when in practice a portion of the lost revenues will be absorbed from utility profits and thus will not affect rates at all.[7]

[5] Direct testimony of Michelle Beck, page 6.
[6] Direct testimony of Stan Faryniarz on behalf of the Division of Public Utilities, at 6.
[7] Direct testimony of Tim Woolf, pages 26-28, lines 479-518.

Residential Demand Charges

Q. The Division supports the use of a demand charge for residential DG customers as one option for mitigating cost-shifting. Do you agree?

A. First, it is important to note that the Division does not support a demand charge as the only rate design option for DG customers. The Division states that it prefers to provide DG customers with a choice of rate designs; specifically, the choice of either the Company's three-part rate structure (which includes a demand charge), or a simple TOU rate with on- and off-peak pricing.[8]

However, I do not believe that a demand charge is appropriate for residential customers, whether they have installed distributed generation or not. I agree with Ms. Beck on this point, where she states that demand charges for residential customers would "represent a fundamental paradigm shift" in rate design for residential customers, and should not be implemented now or in the near future.[9] As discussed in the direct testimony of Ms. Whited, demand charges for residential and small C&I customers violate the fundamental ratemaking principles of efficiency, simplicity, and stability; and are especially difficult for residential and small C&I customers to manage and understand.

8 Direct testimony of Artie Powell, pages 5-6, lines 77-83.
9 Direct testimony of Michelle Beck, page 11, lines 235-237.

<u>Separate Rate Class</u>

Q. The Division notes that it might be reasonable to place DG customers in a separate rate class in order to mitigate cost-shifting. Do you agree?

A. No. The Division concludes that the evidence to support separating DG customers into a different rate class is "mixed."[10] It also concludes that while "separating residential NEM customers into their own rate class is not unreasonable, the Commission may wish to reserve a final decision to do so for a future rate case."[11]

The Division's statement regarding the reasonableness of moving DG customers into a new rate class does not align with the Division's findings regarding the costs to serve NEM customers, or guidance offered by NARUC regarding DG customers. As stated by the NARUC DER manual, "customers are separated into classes based on some important distinction in the service provided to or usages of different groups of customers that affects the cost to serve them," but "if the differences [between groups of customers] are minimal, then it may not be valuable to implement a separate rate class."[12]

The Division's witness, Mr. Farynairz, finds that differences between residential DG and non-DG customers is in fact very minimal. Mr. Farynairz testifies that NEM customer load profiles "on average fall within a reasonably similar range"[13] as non-NEM customers, and that "NEM and non-NEM residential customers have similar unit costs." He also notes that "The similarity in energy unit costs are particularly striking. These

[10] Direct testimony of Artie Power, page 27, line 429.
[11] Direct testimony of Artie Power, page 28, lines 437-439.
[12] NARUC (2016) *NARUC Manual on Distributed Energy Resources Rate Design and Compensation*, pp. 76-77
[13] Direct testimony of Faryniarz, p. 42

numbers indicate that if NEM and non-NEM residential customers were in different classes and the Company used a fixed dollar per kWh charge to collect all revenue from residential customers, the rate for each class would only vary by 0.2 cents/kWh. Such a difference, on its own, would not typically warrant the added costs and complexity of creating another rate class."[14]

Q. Did the Division conduct any other analysis to show differences between NEM and non-NEM customers?

A. Yes, Dr. Powell conducted statistical analysis of NEM customer consumption patterns. However, this analysis is somewhat limited. Dr. Powell compares all NEM customers to all non-NEM customers combined. Such analysis does not recognize that there is great variation in the magnitudes and patterns of consumption of the non-NEM customers.[15]

By singling out one type of residential customer from all the others, Dr. Powell's analysis is implying that all other residential customers are more homogenous than they are. One could compare the load patterns of a variety of different customer types, such as customers with vacation homes, customers with electric space heating, customers with central air conditioning in large homes, or customers that live in multi-family dwellings. These analyses might suggest that such customer types are even more different from non-NEM customers than NEM customers are. Another analysis could be done to remove a set of "atypical" customers (e.g., vacation homes) from the set of non-NEM customers, and compare that subset to NEM customers. My point here is that a complete

[14] Direct testimony of Faryniarz, p. 34

[15] Figure 3 in Ms. Whited's direct testimony indicates that there is significant variation in the consumption patterns across non-NEM customers. Direct testimony of Melissa Whited, page 19, lines 300-301.

understanding of the different load patterns between NEM and non-NEM customers would require significantly more analysis than that provided by the Division.

Q. Do you disagree with the Division's conclusions for other reasons?

A. Yes. The Division's testimony does not address the significant ratemaking, policy, or practical implications of creating a new class of customers. It is important to recognize that it would be neither practical or sustainable to create a new rate class for each new type of technology that customers install behind the meter. Should there be a separate rate class, for example, for customers who install deep energy efficiency retrofits, or electric vehicles, or electric vehicles with storage, or distributed generation that is not solar? It would be premature for the Commission to create a separate rate class for distributed solar customers without first addressing these important policy questions. Furthermore, there are superior methods for addressing concerns regarding cost-shifting, as I discuss below.

Q. The Office recommends including additional meter costs to the monthly customer charge for distributed generation customers. Do you agree?

A. The Office proposes that the customer charge be increased to cover the incremental cost of new meters required for distributed generation.[16] I agree that it is appropriate for DG customers to pay the incremental costs associated with metering the DG generation.

However, a customer charge is not the best means for recovering these incremental costs. I recommend that instead any incremental costs associated with meters

[16] Direct testimony of Michelle Beck, page 21, lines 451-454.

be collected from the DG customer once at the time of installation, since the cost of purchasing and installing a new meter is a one-time cost, rather than a recurring cost.

Either way, any incremental metering costs charged to DG customers should be determined and applied through a general rate case, where the relevant costs can be properly vetted. In addition, any incremental metering costs charged to DG customers should adhere to Utah's long-standing principles for what should be included in a customer charge or an up-front fee, which is consistent with the Division's conclusions.[17]

<u>Changes to NEM Compensation</u>

Q. Should the Commission consider alternatives to the current net metering mechanism to address cost-shifting concerns?

A. While I agree with the Office that there is not an urgent need to address cost-shifting from DG customers at this time, I recognize that continuation of net metering combined with rapid growth in DG resources might, at some point in the future, result in undesirable levels of cost-shifting. Consequently, I recommend that the Commission investigate alternatives to full net metering that could be applied in the future when warranted.

Q. What types of alternative to the current net metering mechanism do you support?

If the Commission determines that modifications to the NEM program are warranted, I support the recommendation of the Office,[18] the Division,[19] and Vote Solar[20] to modify

---

[17] Direct testimony of Faryniarz, p. 41
[18] Direct testimony of Michelle Beck, page 17, lines 368-373.
[19] Direct testimony of Artie Powell, page 30, lines 479-487.
[20] Direct testimony of David DeRamus, page 3, lines 52-55.

the credits that DG customers receive for excess generation from the DG resource. This is the only change necessary to mitigate cost-shifting concerns, and provides the Commission with a great deal of flexibility for doing so. With this change, there is no need to place DG customers in a separate rate class, or to introduce complex, controversial, and risky new rate designs such as residential demand charges.

Q. The Office recommends that the generation from DG customers be netted on an hourly or more frequent basis, rather than on a monthly basis.[21] Do you agree?

A. No. More frequent netting would cause significant challenges for the marketing and adoption of DG technologies. Residential customers are currently billed on a monthly basis and only know their aggregate monthly usage. Without advanced metering infrastructure or potentially expensive third-party products, potential DG customers will not have the information to determine how their hourly consumption and potential generation would align with hourly credits for exports, and thus would not be able to determine the economics of installing DG. Such uncertainty could hinder the ability of DG vendors to market their technologies, and severely limit customer demand for DG technologies.

[21] Direct testimony of Michelle Beck, page 17, lines 368-373.

Q. The Office recommends that the excess generation credits be updated at appropriate intervals in the future.[22] Do you agree?

A. Yes. Over time the value of excess generation will change as the Company's existing resources retire, new resource options become available, and market conditions such as fuel prices change.

However, once a customer has chosen to install DG based on the rates and rate designs available at that time, the Commission should make only limited modifications to the excess generation credits available to that customer in the future. Otherwise, customers would bear too much risk and uncertainty to invest in DG resources.

Q. The Office,[23] the Division, [24] and Vote Solar[25] recommend consideration of time-of-use (TOU) rates for the electricity that DG customers consume on-site. Do you agree?

A. I agree in general. TOU rates can provide more efficient price signals than flat or seasonal rates. However, there are many ways to design TOU rates, and it is important that they be designed carefully to adhere to fundamental ratemaking principles and achieve the state's ratemaking goals. I recommend that the Commission investigate TOU rates as a part of the Company's next general rate case.

[22] Direct testimony of Michelle Beck, page 20, lines 427-430.
[23] Direct testimony of Michelle Beck, pages 17-18, lines 377-380.
[24] Direct testimony of Artie Powell, pages 5-6, lines 77-83.
[25] Direct testimony of DeRamus, pages 78-79, lines 1550-1570

Q. When should the Commission implement alternatives to the current net metering mechanism?

A. As noted above, I agree with the Office and many of the other intervenors that it is not necessary for the Commission to modify the current net metering mechanism in this docket. Instead, the Commission should open a separate docket to investigate what the alternative credits for excess DG generation should be.[26] The Commissions' findings from that proceeding should then be used to establish the new DG excess generation credits, which would take effect at the conclusion of that docket.

5. TRANSITION PLANS AND GRANDFATHERING

Q. The Office, the Division, and Vote Solar have proposed detailed transition plans that have implications for grandfathering DG compensation mechanisms. Do you agree with these proposals?

A. I agree with other intervenors that in this docket the Commission should consider transition plans and how to grandfather DG customers if and when alternatives to net metering are implemented. However, I do not agree with some of the specific recommendations of other intervenors on these points. I briefly address each of these below.

[26] Direct testimony of Michelle Beck, page 18, lines 393-396.

Q. Please summarize the different transition proposals offered by the Office and the Division.

A. The Office recommends the following key elements for a transition plan and grandfathering:

- <u>Existing Net Metering Customers</u>: Customers who have installed DG prior to the release of the Commission's order in this case. These customers would be grandfathered until 2030 (approximately 12 years).

- <u>New Net Metering Customers</u>: Customers who install DG prior to the new NEM cap being reached. The new NEM cap would be designed to be reached at approximately January 1, 2020, or at the time of the next rate case. [27] At that time, a new compensation rate for excess generation (measured on an hourly or more-frequent basis) would be phased in. The phase-in could start at $0.09/kWh and decline by one cent every two to three years until 2030 (when the first version of the "formulaic compensation rate" would go into effect). These customers would also be subject to an updated residential TOU rate with a higher customer charge to recover metering costs and a facilities charge to be implemented in 2030.

- <u>DG Customers Subject to Approved Rates for the New Rate Design</u>: Customers who install DG after a post-NEM rate design is completely in place.[28]

[27] If the cap is not set to be effective at the time of the new rates, then there would be another set of customers who install DG after the net metering cap is reached, but prior to rates being calculated and implemented. This could be avoided by designing the NEM cap to be the same as the effective date for new rates.

[28] Direct testimony of Michelle Beck, pages 23-28

The Division recommends the following key elements for a transition plan and grandfathering:

- GROUP 1: All NEM customers who interconnect before January 1, 2018 would remain on the relevant retail schedule until the end of the transition period. The transition period would last until approximately 2025. However, the Commission could choose to change the compensation rate for Group 1 in the next general rate case.

- GROUP 2: These customers are those that interconnect between January 1, 2018 and the next rate case. They would be billed as current net metering customers (with no change to the underlying Schedule 1 rate), but they would receive a lower compensation rate for excess generation. The Division proposes that this excess generation rate be set at an amount halfway between the average Schedule 1 rate and the Schedule 37 rate (approximately $0.03/kwh for solar) until the next rate case. At the conclusion of the next rate case, Group 2 customers would begin moving toward a new compensation rate at a gradual pace, that would conclude at the end of the transition period (2025).

- GROUP 3: These customers are those that interconnect after the next rate case. They would take the then-current Group 2 rate and effectively join Group 2 in its transition toward the 2025 end date.

- GROUP 4: Group 4 customers are those customers joining after 2025. These customers would join whatever rate structure the Commission has then instituted for all distributed generation customers.[29]

Q. Do you agree with the transition plans and grandfathering approaches offered by the Office and the Division?

A. No. Neither of the plans put forward by the Office or the Division provide a transition path that provides sufficient predictability for customers who may be considering installing DG. As noted in the direct testimony of Mr. Barnes,[30] it is important to understand that residential customers are making a very large investment with their own personal finances when they purchase solar panels. Customers will only continue to make such investments if rates are set to be predictable and of sufficient duration to allow customers to project long-term savings based on reasonable assumptions. For this reason, customers should be able to enroll in a new compensation rate for excess generation that is predictable and durable enough for customers to be able to project whether they will be able to recoup their investment.

For this reason, I offer a slightly different way to define the different types of DG customers than the Office and the Division for the purposes of transitioning from the current net metering rate to an alternative approach that provides reduced credits for excess generation.

[29] Direct testimony of Artie Powell, pages 32-34.
[30] Direct testimony of Justin Barnes, lines 82-87.

Q. What do you recommend regarding transition plans and grandfathering?

A. I recommend that new DG customers be grouped into tranches, with a different excess generation compensation rate set for each tranche. Once enrolled in a tranche, a customer would receive the same compensation rate for excess generation for a specified number of years (15 to 20). An export credit rate would be set in an export credit valuation proceeding for the first tranche of customers, and then in each subsequent rate case for future tranches of customers. The categories of customers that I propose are as follows:

- Existing net metering customers. This group includes all the customers that have installed DG to date, and all the customers that will install DG between now and the conclusion of the export credit valuation proceeding.
  - Compensation: All existing net metering customers' meters should continue to receive net metering compensation for 20 years.[31]
- First tranche of DG customers. This group includes all customers who install DG after the export credit valuation proceeding, but before the next general rate case.
  - Compensation for First Tranche: The first tranche of DG customers should receive excess generation credits equal to the export credit level that is approved by the Commission in the

[31] We concur with the testimony of Dan Black that, "To be effective, grandfathering must apply to the meter at the home where a solar energy system is installed and not to the individual customer. If a customer sells their home, grandfathering must apply to the new buyer's meter to protect the value of the rooftop solar energy system." (Direct testimony of Dan Black, page 1, lines 15-18.)

export credit valuation proceeding, for at least 15 years after the DG installation date.

- The First Tranche customers shall remain on the residential rate structure for consumption applicable to all residential customers.

- <u>Second tranche of DG customers</u>. The second tranche of DG customers would include all customers who install DG after the next rate case that follows the export credit valuation proceeding.

    - The Second Tranche customers should receive excess generation credits as approved by the Commission at the conclusion of the rate case following the export credit valuation proceeding, for at least 15 years after the DG installation date.

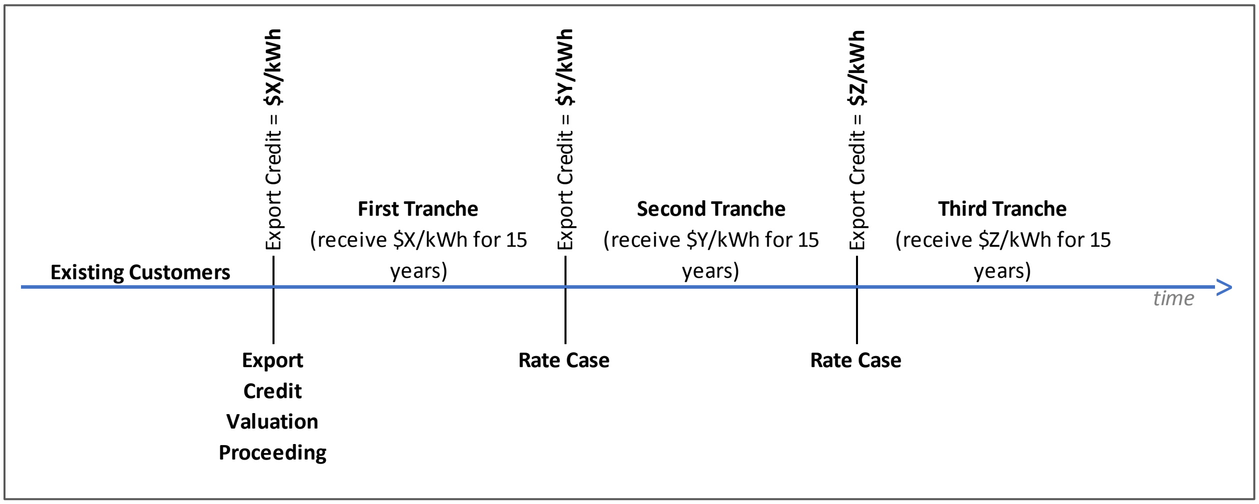
    - The Second Tranche customers shall remain on the residential rate structure for consumption applicable to all residential customers.

- <u>Future tranches of DG customers:</u> Third and subsequent tranches of customers should receive excess generation credits as approved by the Commission at the conclusion of each subsequent rate case, for at least 15 years after the DG installation date.

    - The third tranche and future DG customers shall remain on the residential rate structure for consumption applicable to all residential customers.

The figure below illustrates our proposal.

Figure 1. Proposed timeline for setting alternative credits for DG customers



Q. Is grandfathering existing DG customers standard practice?

A. Yes, as noted by Mr. Barnes and other intervenors, states typically allow grandfathering in one form or another. As recently reported in *Fortune*, "while solar rates around the U.S. are being reexamined by state agencies, few regulators have actually changed the rates for existing solar customers."[32]

Q. Why do states typically allow grandfathering for net energy metering tariffs?

A. One chief reason grandfathering is done is because failure to grandfather existing customers is widely viewed as economically unfair to the customers who already installed on-site generation.

For instance, when California ruled in favor of grandfathering, the Public Utilities Commission of California stated that it was

[32] Fehrenbacher, Katie, *Why Nevada Brought Back Favorable Rates for Existing Solar Customers*, Fortune (Sep 16, 2016), available at <http://fortune.com/2016/09/16/nevada-solar-grandfathering/>.

> persuaded that customers who invest in renewable distributed generation systems and participate in existing [net energy metering] tariffs should at least have an opportunity to recoup their initial investment in distributed renewable generation. In addition, we find that adopting a transition period that denies customer-generators the opportunity to realize their expected benefits would not be in the public interest, to the extent that it could undermine regulatory certainty and discourage future investment in renewable distributed generation.[33]

To the same end, the Arizona Corporation Commission clarified that its decision to grandfather existing customers was

> not intended to shield customers with DG systems from generally applicable rate design changes, such as changes for the basic service charge. It is, instead, intended to preserve the expectations that customers with DG systems may have relied upon when they chose to adopt DG technology.[34]

Q. Has any state prohibited grandfathering for net energy metering tariffs?

A. No, not to my knowledge. When a utility or regulatory body has proposed to require existing customers with distributed generation to move to a new rate, it has generated significant controversy and negative press. A prominent example is Nevada, as discussed by Mr. Barnes, Ms. Clements, and Mr. Black.[35]

---

[33] *See* Public Utilities Commission of the State of California, *Decision Establishing a Transition Period Pursuant to Assembly Bill 327 for Customers Enrolled in Net Energy Metering Tariffs*, Rulemaking 12-11-005, Decision 14-03-041 (Mar. 27, 2014), at 20, available at <http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M089/K386/89386131.PDF>.

[34] Arizona Corporation Commission, *In the Matter of the Commission's Investigation Value and Cost of Distributed Generation*, Docket No. E-00000J-14-0023, Decision No. 75859 (Jan. 3, 2017), at 156, available at <http://docket.images.azcc.gov/0000176114.pdf>.

[35] Direct testimony of Justin Barnes, lines 247-259; Direct testimony of Allison Clements, page 46; Direct testimony of Dan Black, page 6.

6. SUMMARY OF RECOMMENDATIONS

Q. What are your recommendations?

A. Nothing in the direct testimony of other intervenors causes me to modify my original recommendation that the Commission reject RMP's proposed net metering compensation mechanism. The Company's proposal (a) is unnecessary for addressing cost-shifting at this time; (b) violates several key ratemaking principles; and (c) will have a chilling effect on the development of DG in Utah.

Nonetheless, I recognize that continuation of net metering combined with rapid growth in DG resources might, at some point in the future, result in undesirable levels of cost-shifting. Therefore, I support the recommendation of the Office and the Division that the Commission consider alternatives to full net metering, particularly the recommendation of the Office to alter the credit for excess generation from DG. This one modification to the crediting mechanism can sufficiently mitigate cost-shifting and avoid the need for more drastic and problematic modifications, such as creating a new customer class or imposing demand charges on DG customers. Such changes should be implemented at the time of the next general rate case,[36] or in a separate proceeding to set alternative bill credits for excess generation.

Finally, I recommend that the Commission establish alternative compensation levels for excess generation that are predictable and of sufficient duration to allow customers to project long-term savings based on reasonable assumptions. Specifically, I recommend that all existing net metering customers and those who install DG prior to the

[36] Beck Direct Testimony at 18, and Powell Direct Testimony at 6.

conclusion of the next RMP rate case (or export compensation docket) continue to receive net metering compensation for at least 20 years after their DG installation date. For subsequent DG customers, I recommend that these customers be grouped into tranches, with a different excess generation compensation rate set for each tranche. Once enrolled in a tranche, a customer would receive the same compensation rate for excess generation for at least 15 years.

Q. Does this conclude your rebuttal testimony?

A. Yes, it does.