ROCKY MOUNTAIN POWER
A DIVISION OF PACIFICORP

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September 15, 2020

VIA ELECTRONIC FILING

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

Attention: Gary Widerburg
Commission Administrator

RE: **Docket No. 17-035-61 – In the Matter of the Application of Rocky Mountain Power to Establish Export Credits for Customer Generated Electricity**
Surrebuttal Testimony

Pursuant to the Phase II Scheduling Order and Notice of Public Witness Hearing, and Notice of Hearing issued January 16, 2018 in the above referenced docket, Rocky Mountain Power (the "Company") hereby submits for filing its surrebuttal testimony.

The Company respectfully requests that all formal correspondence and requests for additional information regarding this filing be addressed to the following:

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Sincerely,

Joelle Steward
Vice President, Regulation

Rocky Mountain Power
Docket No. 17-035-61
Witness: Joelle R. Steward

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

Surrebuttal Testimony of Joelle R. Steward

September 2020

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

A. Yes.

Purpose and Summary of Surrebuttal Testimony

Q. What is the purpose of your surrebuttal testimony?

A. My surrebuttal testimony responds to various policy arguments raised by other parties in their rebuttal testimony submitted on July 15, 2020, in response to the Company's proposed net billing program and export credit rate filed on February 3, 2020 ("Net Billing Program"). Specifically, I summarize and/or respond to testimony submitted by the Division of Public Utilities ("Division") witness Mr. Robert A. Davis; the Office of Consumer Services ("Office") witness Ms. Michele Beck; Utah Clean Energy ("UCE") witness Ms. Kate Bowman; Vivint Solar witness Dr. Christopher Worley; the Utah Solar Energy Association ("USEA") witness Mr. Ryan Evans; and Vote Solar witness Mr. Sachu Constantine. The policy arguments of the parties are largely repeated and for purposes of brevity, I will only respond to new proposals and specific statements that were made by parties in rebuttal testimony.

Q. Please summarize your surrebuttal testimony.

A. The Company's proposed export credit rate alternatives as described by Company witness Mr. Daniel J. MacNeil, offer a sustainable Net Billing Program structure for customer generators that fairly balances the interests of customer generators and other non-participating customers. UCE, Vivint Solar, USEA and Vote Solar make various recommendations and proposals in attempt to continue a current or increased export credit rate that is unsustainable, not lowest cost, and shifts costs to other customers.

The Company's Net Billing Program offers a fair and balanced approach to support energy choices.

Q. Please summarize the Company's proposal as of this surrebuttal testimony.

A. The Company's proposal is relatively consistent with its initial filing in February 2020, with a few changes in response to parties' testimony. In summary, the Company's recommendation is:

- Approve Electric Service Schedule No. 137 – Net Billing Service ("Schedule 137") for new customer generators, effective January 1, 2021. The net billing tariff will provide export credits to customer generators for all energy exported to the grid from their generation system. Customer energy use that is provided by the Company will continue to be billed under the standard applicable service schedule. Energy generated and consumed onsite by customers will offset kilowatt-hours that would otherwise have been imported from the Company to the customer.
- Adopt a methodology to calculate the Export Credit Rate annually, using one of the alternative approaches in Mr. MacNeil's surrebuttal testimony. Mr. MacNeil presents export credit rates two ways: (1) based on the approved methodology for forecasting qualifying facility avoided costs, which results in an initial average export credit rate of 1.53 cents per kilowatt-hour ("kWh"); and (2) based on historical Energy Imbalance Market ("EIM") prices, which results in an initial average export credit rate of 2.22 cents/kWh. Under either approach the Company proposes to differentiate the rates by time of day and season.

- Establish a process to update the export credit rates annually. The Company would file annually on April 30th to reflect the most recent information (e.g., avoided line losses, integration costs, market price curves), consistent with the methodology approved in this proceeding, with a July 1st effective date for the annual export credit update.
- Approve a one-time, non-refundable application fee of $150 for interconnection applications under Schedule 137.
- Approve a one-time, customer generation meter fee of $160 for interconnection applications under Schedule 137.
- Close Schedule 136 to new applications received after December 31, 2020.

Q. Vivint Solar and Vote Solar accuse the Company of being motivated by self-serving interests. How does the Company respond to these claims?

A. As I stated in my rebuttal testimony, the primary motivation behind the Company's recommendation is to minimize cost shifting to other customers by setting a rate that fairly compensates customer generators for the value of the energy they contribute to the grid. The Division and the Office generally support the net billing tariff and export credit rate. The Division's mission is to "act in the public interest" to "promote the safe, healthy, economic, efficient, and reliable operation of all public utilities" at "just, reasonable, and adequate rates."[1] The Office is a consumer advocate responsible for advocating for the "most advantageous" position for residential and small consumer customers of utilities.[2] The Office identified two adjustments to the Company's export

[1] Utah Code Ann. § 54-4a-6; *see also* About the Utah Division of Public Utilities, https://dpu.utah.gov/about.html (last accessed September 13, 2020).
[2] Utah Code Ann. § 54-10a-301; *see also* Office of Consumer Services: About Us, https://ocs.utah.gov/about.html (last accessed September 13, 2020).

credit rate, but generally concluded that overall the Company's proposal was consistent with true cost-based rates and highly preferable to the proposals offered by Vivint Solar and Vote Solar. If the Company's proposed export credit rate primarily served the Company's own interests, as claimed by Vivint Solar and Vote Solar, it would not be supported by the Division and the Office in such a manner. The export credit rate paid to customer generators is borne by other customers and the level of the credit does not impact the Company's earnings. Parties that attempt to argue that the Company's motivation is purely self-interest demonstrate a fundamental lack of understanding of regulation and how utility rates are set.

Q. UCE witness Ms. Bowman and USEA witness Mr. Evans recommend the Transition Program be maintained until the Transition Program cap has been reached. Do you agree?

A. No. This recommendation is contrary to the terms of the Settlement Stipulation in Docket No. 14-035-114 ("NEM Stipulation") to which UCE and USEA were signatory parties. Paragraph 15 of the NEM Stipulation stated:

> 15. The Commission will establish a transition program ("Transition Program") for customer generation systems as specified in Utah Code Ann. § 54-15-102(3), who submit an interconnection application after the NEM Cap Date ***until the earlier of***: (a) the date on which the Transition Cap is reached, as provided in Paragraph 22 below, or (b) the date the Commission issues a final order in the Export Credit Proceeding, as provided below ("Transition Customers"). (emphasis added)

Accordingly, the Commission should reject the proposals to maintain the Transition Program rate until the Transition Program cap has been reached because they are at odds with the NEM Stipulation approved by the Commission. UCE also states its support for Vote Solar's proposal to reinstate net metering, which as I described in my rebuttal testimony, would clearly violate the Commission-approved NEM Stipulation and severely undermine settlement efforts for regulatory matters in the future.[3] The Company found the proposal to reinstate net metering to be concerning enough coming from Vote Solar, who was not a signatory party to the NEM Stipulation, but finds the support of such a proposal particularly disconcerting when coming from a signatory party to the NEM Stipulation.

Q. Please summarize Ms. Bowman's proposed "glide path" for the transition to the new export credit rate.

A. Ms. Bowman suggests that if the value of the export credit rate is ultimately set at a level that is lower than the Transition Program rate, that it be implemented with the following glide path:

Figure 1 Utah Clean Energy's Proposed Glide Path

Export Credit Value (% of average retail rate)	Total Capacity Available
90% for schedules 1, 2, and 3; 92.5% for all other schedules (current Transition Program rate)	240 MW (170 MW res./small comm. & 70 MW large comm.)
85%	80 MW
80%	80 MW

Etc. until final value of Export Credit is reached.

Ms. Bowman goes on to lay out a process as to how each rate tier would become effective.

[3] *See* lines 185-199 of Rocky Mountain Power witness Ms. Steward Rebuttal Testimony.

Q. Does the Company agree the glide path implementation process proposed by Ms. Bowman should be adopted?

A. No. Ms. Bowman's glide path process adds unnecessary complexity into the rate setting process and program administration. As I stated in my rebuttal testimony, gradualism has already been utilized in this docket and its predecessor, Docket No. 14-035-114 ("NEM Docket").[4] By the time the new export credit rates and Schedule 137 are implemented in this proceeding, the solar industry will have had almost seven years to adapt to the changes. Ms. Bowman even hints that her proposed glide path would not be the end of the attempts to delay the transition with her statement that "this gradual phase-in schedule allows the Commission and other stakeholders to regularly monitor the impact of each rate tier and consider additional changes to the glide path in the future if necessary."[5] At some point, the parties in this proceeding must accept the reality that the current unsustainable program offering for customer generators must be remedied. Continuing to delay the necessary move to a principled and equitable program for customer generators is not in the public interest.

Q. Did any other party advocate for a glide path in their rebuttal testimony?

A. Yes. USEA witness Mr. Evans also argues that a glide path is necessary to protect jobs and capital investment in Utah and that the gradual shift that this regulatory process has provided is not enough. Mr. Evans points to the COVID-19 public health emergency as further reason why special care should be afforded to the solar industry.[6]

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[4] *See* lines 74-91 of Rocky Mountain Power witness Ms. Steward Rebuttal Testimony.
[5] *See* lines 1110-1112 of UCE witness Ms. Bowman Rebuttal Testimony.
[6] *See* lines 36-61 of USEA witness Mr. Evans Rebuttal Testimony.

Q. Similar to USEA, Vote Solar, Vivint Solar and UCE continue to argue that a higher export credit rate is justified based on the alleged impacts to the solar industry. How do you respond?

A. Division witness Mr. Davis astutely points out that "on a grander scale and more difficult to estimate, is the impacts Vote Solar's proposed rate might have on the general Utah Economy."[7] Mr. Davis then goes on to describe the "avalanche effect" and an "unsustainable frenzy" that an extremely high rate like that Vote Solar is proposing would have on the system. Similarly, Ms. Beck points out that neither Vote Solar nor Vivint Solar addressed the potential economic impacts due to early shut down or partial displacement of existing resources, and that the evidence used by parties in their claims of economic benefits of solar are at best "speculative."[8] The Company agrees with Mr. Davis and Ms. Beck that there is a real risk of harm to non-solar customers and industry in Utah, if the export credit rate is allowed to be set at unsustainably high levels. The effects on *all* customers should be considered. Vote Solar, Vivint Solar, UCE and USEA continue to focus on the impact to a single industry without consideration for the impacts their proposal will have on the other industries and jobs that rely on affordable electric rates. To specifically address Mr. Evan's claim that the solar industry should receive special consideration due to COVID-19 public health emergency, the Company responds that *all* of the Company's customers have been affected by the pandemic to varying extents. For many of the Company's commercial and industrial customers, who also provide jobs and capital investment to Utah's economy, their electric bill is a significant portion of their operating costs.

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[7] *See* lines 268-269 of *DPU* witness Mr. Davis Rebuttal Testimony.
[8] *See* lines 143-163 of OCS witness Ms. Beck Rebuttal Testimony.

Asking those customers to pay more than is reasonably justified in order to support a single sector of the economy is, by definition, a violation of the public interest.

Q. Mr. Evans opines that the Company supports renewable resources only when they can own/control them and has acted to stifle competition. Do you wish to respond to these statements?

A. Mr. Evans cites three examples that caused him to form the opinion that the Company stifles competition: 2016 proposal to end net metering, House Bill 261 (2018), and House Bill 411 (2019). As an initial matter, it is important to note that all of these instances require regulatory oversight and approval before they can be effectuated. Moreover, legislation, by its very nature, establishes what is in the public interest. I will respond to each of these examples individually, but generally Mr. Evans' opinion that the Company stifles competition is not supported by these examples.

2016 Proposal

As directed by the Commission, on November 9, 2016, the Company submitted a filing in compliance with the Commission's order in Docket No. 14-033-114, demonstrating that the costs of the net metering program then in place outweighed the benefits and proposing changes because "customers with private solar generation systems have unique load and cost characteristics that support a new rate structure."[9] In that filing, the Company provided two cost of service studies: an actual cost of service study, and a "counterfactual" cost of service study assuming no net metering. This analysis showed that the costs of the net metering program were being shifted to non-net

[9] *In the Matter of the Investigation of the Costs and Benefits of PacifiCorp's Net Metering Program*, Docket No. 14-035-114, Compliance Filing and Request to Complete All Analyses Required under the Net Metering Statute for the Evaluation of the Net Metering Program, at 3 (November 9, 2016).

metering customers and that the amount of cost shifting was growing as more customers installed customer generation facilities. The Company also provided additional support for the administrative and engineering costs included in the study. Mr. Evans has pointed to no aspect of the 2016 compliance filing that supports his claim that its intent was to "stifl[e] competition," rather than its stated purpose to prove and remedy the unfair cost shifting caused by the net metering program.

<u>H.B. 261 and H.B. 411</u>

House Bill 261, Renewable Energy Amendments ("H.B. 261"), passed by the Utah Legislature in 2018, encourages competition by allowing the Company to be treated as other private solar developers in federal normalization tax rules in order to receive and be able to pass back to customers the full benefit of federal investment tax credits. Prior to H.B. 261, members of USEA were able to take advantage of this full benefit while Rocky Mountain Power was not. Importantly, H.B. 261 requires the Commission to only approve a request from the Company to utilize this process if "the commission determines that the solicitation and evaluation processes to be used will create a level playing field in which the qualified utility and other bidders can compete fairly."[10]

It is noteworthy to point out that Mr. Evans and members of USEA opposed the original language of H.B. 261 and demanded a provision in statute prohibiting Rocky Mountain Power from receiving the full benefit of federal investment tax credits for any resource under two megawatts. After the provision was included, USEA did not oppose the bill, and the bill passed. The Transition Program tariff requires a customer to be two megawatts or less, effectively prohibiting Rocky Mountain Power from

[10] Utah Code Ann. § 54-17-807(6)(b).

utilizing House Bill 261 for the Transition Program or any future project built under the new export rate proceeding.

H.B. 261 requires a level playing field for projects over two megawatts while discouraging the Company from entering the market on projects under two megawatts, the only kind of projects that could compete with the customer generation facilities at issue in the current Commission proceeding. It is especially misleading that USEA would testify that Rocky Mountain Power is "effectively stifling competition" due to H.B. 261 when the Company has not utilized this legislation to build a single project to date.

Similarly, House Bill 411, Community Renewable Energy Act ("H.B. 411"), passed during the 2019 Utah legislative session, allows the Company to participate in a "competitive solicitation process" that supports the program by providing an option for the utility to own the resource. Like H.B. 261, H.B. 411 requires that any resource owned by the Company must be "in the interest of participating customers and other customers of the qualified utility."[11] This language was included in the bill at the request of renewable advocates, including members of USEA, who did not oppose the bill in any public hearing where it was debated.

Q. Vivint Solar witness Dr. Worley takes exception with the characterization of the solar market in your direct testimony. Would you please address his issues?

A. The purpose of the discussion of the solar industry included in my direct testimony was simply to illustrate that the economic circumstances for rooftop solar between now and when net metering was first instituted in Utah are markedly different, which point to

[11] Utah Code Ann. § 54-17-908(2)(b).

the reduced need to subsidize the solar industry. In my direct testimony, I made the following general statement about the history of Utah's solar market, "During this timeframe [2002-2013], the price of solar panels rapidly decreased and government subsidies were implemented, resulting in rapid growth of net metering adoption." While Dr. Worley generally admitted that my facts are correct, he criticizes my statement as being "reductionist," and he erroneously leaps to the conclusion that I meant "these two factors alone led to the rapid growth in solar adoption."[12] My statement did not explicitly state, nor did I intend to imply that the decreasing price of solar panels and government subsidies were the only contributing factors to the solar industry's growth. A comprehensive analysis of the factors that contributed to the solar industry's growth would be outside the scope of this proceeding, which is intended to develop an export credit rate that mitigates the cost shifting from customer generators to other customers. I also do not dispute Dr. Worley's statement that other forms of energy receive government subsidies. But including a complete listing of energy sources that receive a government subsidies is similarly irrelevant to developing an export credit rate.

Q. Dr. Worley argues that "cost reductions do not magically happen."[13] Do you dispute this contention?

A. No. The solar industry should be applauded for the innovation and efficiency gains achieved. In fact, that should give the Commission comfort that the industry will continue to evolve and adapt as this customer generation subsidy is reduced. Again, I am unclear as to how the costs to install solar panels is relevant to what customer

[12] *See* line 130 of Vivint Solar witness Dr. Worley Rebuttal Testimony.
[13] *See* lines 159-160 of Vivint Solar witness Dr. Worley Rebuttal Testimony.

generators should be paid for the excess generation that they export to the grid. Dr. Worley appears to be trying to use the general statement I made about declining solar costs to dispute the overarching principle here that "solar customers are not paying their fair share of system costs."[14] The Company does not deny Dr. Worley's claims that the solar industry has contributed to the decrease in the installed cost of solar panels through innovation, but the specifics surrounding the cost of solar installation is not relevant to this proceeding to establish the export credit rate.

Q. Vote Solar witness Dr. Berry claims that allowing export credits to expire annually does not deter customers from oversizing their system.[15] Did Vote Solar make any new recommendations to address system oversizing?

A. Yes. Vote Solar recommends that installers be required to verify expected annual load using the customer's historical meter data or a Company-approved proxy as part of the interconnection application process.[16]

Q. Do you agree?

A. No. Vote Solar's proposal to cap the facility size at the time of installation based on historical usage is a much less flexible approach than creating a financial incentive to right-size a facility. Moreover, the Company disagrees with giving solar installers discretion to "allow for projected changes" as the only check on ensuring a customer right-sizes their facility. There would be nothing to prevent solar installers from assuming that customers would purchase one or more electric vehicles and other high-consumption consumer goods in order to inflate the projected needs of the customer.

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[14] *See* lines 183-184 of Vivint Solar witness Dr. Worley Rebuttal Testimony
[15] *See* lines 742-766 of Vote Solar witness Dr. Berry Rebuttal Testimony.
[16] *See* lines 792-801 of Vote Solar witness Dr. Berry Rebuttal Testimony.

Such an approach would create a greater burden and potential delay in processing applications than the financial incentive of an annual expiration of export credits.

Q. How does the Company's proposal provide a better incentive for customers to size their systems appropriately?

A. The annual expiration of export credits provides a valuable check-in point to encourage customers to think about the relationship between their consumption and their generation both when installing and using their onsite generation. Furthermore, consistent with Schedule 136, the value of expiring credits from Schedule 137 would be credited to all customers as part of the Energy Balancing Account. As such the Company will not be directly impacted by the credit expiration. The annual credit expiration encourages the right sizing of facilities in a less punitive and long-term manner and allows customers to consider how their usage may change over time when making a decision on facility sizing.

The new net billing export credit rate will also discourage customers from oversizing their systems. Under the Company's proposal, customer generators will receive the highest benefit when their production reduces deliveries by the Company and avoids retail rates. Customer generators would receive a significantly reduced benefit when the production exceeds their own consumption, as the Company's proposed export credits are lower than retail rates. As a result, even if a customer's annual production was equal to or somewhat greater than their annual consumption, their export credits would likely be lower than the retail charges they would offset, resulting in no excess credit expiration.

Conclusion

Q. Please summarize your recommendation?

A. The Company recommends the Commission approve its proposed export credit rate, as revised in the Company's surrebuttal case, as well as the proposed Net Billing Program. These proposals provide customers the opportunity to invest in onsite generation while protecting other customers from the effects of that decision. The proposals set forth by UCE, Vivint Solar, USEA, and Vote Solar should be rejected.

Q. Does this conclude your surrebuttal testimony?

A. Yes.

Rocky Mountain Power
Docket No. 17-035-61
Witness: Daniel J. MacNeil

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

Surrebuttal Testimony of Daniel J. MacNeil

September 2020

Q. Are you the same Daniel J. MacNeil that presented direct and rebuttal testimony in this proceeding?

A. Yes.

Purpose of Surrebuttal Testimony

Q. What is the purpose of your surrebuttal testimony?

A. I respond to the rebuttal testimony of Vote Solar witnesses Dr. Michael Milligan, Mr. Curt Volkmann, Dr. Carolyn Berry, and Mr. Sachu Constantine; Vivint Solar witness Dr. Christopher Worley, Utah Clean Energy ("UCE") witness Ms. Kate Bowman, and OCS witness Mr. Hayet. My testimony supports the Company's proposed export credit rates for Schedule 137 – Net Billing Service.

Q. Please provide a summary of your surrebuttal testimony.

A. The witnesses for Vote Solar, Vivint Solar, UCE, and OCS raise various objections related to the Company's proposed export credit rates. For a variety of reasons, the witnesses' proposals concerning avoided energy costs, capacity value, integration costs and grid services are not consistent with the costs non-participating customers would otherwise incur in the absence of exports under the proposed Schedule 137.

Vote Solar has proposed including avoided secondary line losses in the export credit rate, and this proposal is supported by OCS. In response, the Company has modified its proposal to account for the net impact of avoided and incremental losses on the secondary distribution system, in addition to the avoided primary and transmission losses in its initial filing. This results in a small increase in export credit value.

Many conditions can cause export credit values to increase or decrease over time, and the direction and magnitude of those changes is uncertain. Annual updates to export credit rates will ensure that the export credit rate remains accurate and that non-participating customers do not bear the risk of changes in value over time. While the export credit rate will change over time, customer generation ("CG") production that offsets a customer's onsite demand will avoid retail energy charges and thus will not be affected by export credit rate changes. Parties' proposals to fix export credit values for an extended term would shift risks to non-participating customers and should be rejected.

The on-peak and off-peak definition does not change the effective compensation for the average export profile; however, distinguishing between on-peak and off-peak periods helps ensure that the compensation paid to customers with different export profiles is consistent with the value they provide. The Company's proposal for a four-hour on-peak period differentiated by summer and winter seasons provides a reasonable differentiation between periods of higher and lower value while retaining a relatively simple structure. The Company does not intend to modify the on-peak and off-peak definition on an annual basis, as this would result in administrative burden and customer confusion that is unwarranted given the likely small level of change. It would be more appropriate to revisit these definitions in a general rate case where they can be addressed holistically. Parties' proposals to eliminate differentiated rates should be rejected because they fail to account for the difference in the value of CG exports across time and would result in less accurate compensation for differently-situated Schedule 137 customers.

Q. What are your recommendations?

A. The Company has presented export credit rates two ways: (1) based on the approved methodology for forecasting qualifying facility avoided costs in Exhibit RMP___(DJM-1SR); and (2) based on historical Energy Imbalance Market ("EIM") prices in Exhibit RMP___(DJM-2SR). While a forecast is specific to the rate effective period, and historical EIM prices would be more transparent for parties to review, either method provides a reasonable basis for setting time-differentiated export credit rates that are updated annually. The Company recommends that the Commission approve the Schedule 137 export credit rates and structure as filed by the Company and require annual updates to ensure avoided costs continue to align with the compensation provided for CG exports.

Export Profile

Q. Mr. Constantine asserts that the Company relied on an analysis of the Schedule 135 load research data performed by DPU witness Robert Davis in its export credit proposal.[1] Is this accurate?

A. No. The Company did not rely on Mr. Davis' analysis of the load research study sample data to justify the Company's proposed Export Credit Rate ("ECR"). Rather, the Company relied on its own records of export profiles derived from the census of Schedule 136 customers.

[1] *See* lines 532-533 of Vote Solar witness Mr. Sachu Constantine's Rebuttal Testimony.

Q. Do you agree with Mr. Constantine's assertion that the sampling uncertainty for estimates derived from Schedule 135 load research samples affects the calculation of the Company's export credit?[2]

A. No. The Company's proposal does not use production or export profiles derived from the Schedule 135 load research samples. Rather, the Company's proposed export credit relies on the census of Schedule 136 customer exports, which are not subject to sampling error.

Q. Ms. Bowman asserts that it would take the exports of more than 20,000 customer generators to equal the output of a qualifying facility.[3] Do you agree?

A. No. There is no minimum size for qualifying facilities ("QFs"), and while 80 megawatts ("MW") is the maximum for small power production facilities, such as solar resources, the Company has contracted with a number of Utah solar QFs that are 3 MW or less. Federal Energy Regulatory Commission regulations dictate that published pricing be available to all QFs up to 100 kW, which shows that resources comparable in size to rooftop solar generators are contemplated as QFs. Moreover, because a portion of CG production offsets the customer's own load, no aggregation of CG exports is likely to result in an export profile equivalent to the entire output of a solar facility.

Avoided Energy Costs

Q. What objections do parties' raise with regard to the Company's proposal for avoided energy costs?

A. UCE and Vote Solar object to the Company's use of historical prices in its export credit proposal. UCE, Vivint Solar, and Vote Solar object to the Company's proposed use of

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[2] *See* lines 533-539 of Vote Solar witness Mr. Sachu Constantine's Rebuttal Testimony.

[3] *See* lines 382-387 of UCE witness Ms. Bowman's Rebuttal Testimony.

the GRID model, while OCS identifies certain modeling changes that it suggests will improve the results.

Q. What role does Vote Solar attribute to historical market price data in the Company's proposal?

A. Dr. Milligan claims that the Company's adjustment of GRID model outputs using historical EIM prices results in incorrect estimates of avoided energy costs.

Q. Do historical EIM prices impact the total avoided energy costs determined by the Company using the GRID model?

A. No. Historical EIM prices are only used to spread the results from the GRID model forecast between on-peak and off-peak periods. The historical EIM prices do not increase or decrease the total avoided energy value associated with the CG export profile.

Q. Is there a significant disconnect between historical EIM prices and the Company's proposed rate effective period?

A. No. In my direct testimony, I proposed using historical EIM prices from the 36 months ending October 2019, to determine the timing and differential of export credit payments during the proposed rate effective period of calendar year 2021. While conditions far into the future may not be aligned with recent EIM operations, the Company's proposal focuses on the near term in recognition of the fact that conditions are subject to change over time.

Q. Are Vote Solar's proposed avoided energy costs reliant on historical pricing in much the same way that EIM prices were applied in the Company's proposal?

A. Yes. Vote Solar witness Dr. Milligan has proposed that hourly market prices based on the Company's Official Forward Price Curve ("OFPC") be used to determine avoided energy costs and both UCE and Vivint Solar support this approach on the basis that future prices are more accurate than historical prices.[4,5,6] Dr. Milligan cites the Company's response to Vote Solar Data Request 12.3 in support of this conclusion and includes a portion of that response in his rebuttal testimony.[7] The Company's response to Vote Solar Data Request 12.3 goes on and states the following:

> The OFPC is a set of monthly heavy load hour (HLH) / light load hour (LLH) price curves for five markets (California-Oregon Border (COB), Mid-Columbia (Mid-C), Palo Verde (PV), NP15, and SP15). Hourly scalars can be applied to the OFPC to shape the OFPC by hour. Hourly scalars are calculated quarterly, using the most recent 24 full months of CAISO day-ahead hourly prices at the CAISO's Malin scheduling point (for PacifiCorp West (PACW)) and the CAISO's PV scheduling point (for PacifiCorp East (PACE)).

As a result, the hourly OFPC values Dr. Milligan supports are also reliant upon historical market information in much the same way as the EIM prices used in the Company filing.

Q. Why did the Company propose using EIM for price shaping, rather than hourly prices from its OFPC?

A. The hourly scalars used in the OFPC are commercially sensitive as they are used to inform offers for wholesale electric power transactions to cost-effectively balance the Company's loads and resources. The use of publically-available EIM data allows for more transparency, as it is not confidential.

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[4] *See* lines 177-228 of Vote Solar witness Dr. Milligan's Revised Affirmative Testimony.
[5] *See* lines 44-46 of UCE witness Ms. Bowman's Rebuttal Testimony.
[6] *See* line 289 of Vivint Solar witness Dr. Worley's Rebuttal Testimony.
[7] *See* lines 208-223 of Vote Solar witness Dr. Milligan's Rebuttal Testimony.

Q. Dr. Milligan advocates using the OFPC to incorporate future changes in the resource mix of the western interconnect into the ECR.[8] Do the hourly OFPC values fully reflect future resource changes?

A. No. While future resource changes impact the monthly HLH and LLH prices produced in the Company's OFPC, the hourly price scalars for all years are based on the same historical data.

Q. Please describe how hourly market prices might be impacted by likely future resource changes.

A. Resource mix changes consist of resource retirements and resource additions. The Company's 2019 Integrated Resource Plan ("IRP") preferred portfolio includes a significant number of coal and gas units that are expected to retire in the next twenty years. Many coal and gas units owned by other utilities are also expected to be retired in that time frame. These resources are frequently economic and are able to provide relatively constant capacity throughout the day. All else equal, the removal of this economic generation would result in increased generation from resources with higher variable costs, and thus result in higher market prices throughout the day. The Company's 2019 IRP preferred portfolio also includes a significant quantity of new solar resources, which have zero variable costs, but only deliver during daylight hours. The addition of this incremental daytime supply would tend to drive down prices during daylight hours. The combination of these effects is higher prices in the evening and at night, and lower prices during the day.

[8] *See* lines 224-233 of Vote Solar witness Dr. Milligan's Rebuttal Testimony.

Q. How would changes in resource mix impact the value of CG exports?

A. The avoided energy value of CG exports would tend to decline relative to a resource that was available in all hours as the penetration of solar resources increases over time.

Q. Does the OFPC replicate this effect?

A. No. The OFPC only reflects changes in monthly average prices for HLH and LLH periods. To the extent the addition of solar resources would exert downward pressure on prices, it would be reflected in the average price for the HLH period that includes most daylight hours. However, the hourly shaping in the OFPC does not account for the evolving resource mix over time, so it would not reflect the continued decline in value during daylight hours that would result from increasing solar penetration.

Q. Can the GRID model replicate the effect of portfolio changes on avoided energy costs?

A. Yes. The GRID model includes the 2019 IRP preferred portfolio, and has both resource retirements and resource additions. Because the ability to buy and sell power in wholesale markets is limited in GRID (consistent with actual operations), lower cost alternatives in PacifiCorp's portfolio are displaced as more solar resources are added.

Q. Does the GRID model intrinsically capture portfolio-related effects?

A. No. The GRID model accounts for the inputs and constraints supplied by the user. To the extent inputs allow for unconstrained transfers between a point of interest and electric markets, the GRID model would not show portfolio-related effects. OCS witness Mr. Hayet describes how modifying the inputs for transfer capability and market sales limits (a.k.a. market depth or market caps) impacts the results reported by the GRID model.[9]

Q. Mr. Hayet proposes that market sales limits be removed during HLH periods.[10] What would this do to the portfolio-related effects in GRID?

A. Removing market sales limits will result in diminished portfolio-related effects. As indicated above, the Company's hourly OFPC does not incorporate shifts in the relative value from hour to hour as a result of increasing solar resource penetration. By allowing additional sales valued at the hourly OFPC, Mr. Hayet's proposal reduces the effect of solar resource penetration on price even further.

Q. Have other witnesses acknowledged that there is a relationship between solar resources and market price?

A. Yes. Vote Solar witness Dr. Berry recognizes that solar resources can result in lower market prices.[11] UCE witness Ms. Bowman also identifies market price suppression as a benefit of solar resources.[12]

Q. Mr. Hayet indicates that the Company was unable to explain the need for market caps in GRID in response to a data request. Is this accurate?

A. No. Mr. Hayet's testimony indicates that the OCS data request 7.3c in this docket failed to explain "the history of the factors that originally led to the need for the market cap modeling in GRID".[13] The Company's response referenced the myriad ways in which market transactions are hindered in actual operations, with variations in prices in

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[9] *See* lines 416-433 of OCS witness Mr. Hayet Rebuttal Testimony.
[10] *See* lines 428-433 of OCS witness Mr. Hayet's Rebuttal Testimony.
[11] *See* lines 398-403 of Vote Solar witness Dr. Berry's Revised Affirmative Testimony.
[12] *See* lines 681-698 of UCE witness Ms. Bowman's Rebuttal Testimony.
[13] *See* lines 424-427 of OCS witness Mr. Hayet's Rebuttal Testimony. Mr. Hayet's Rebuttal testimony references OCS data request 7.4, but OCS has clarified that the intended reference was OCS data request 7.3.

response to demand, block transactions (such as a 25 MW by 16-hour HLH product), and limits on counterparty interest. These factors were relevant in the past and remain relevant today. Prices in the GRID model are fixed and transactions are hourly for fractions of a MW. If the cap on market sales is removed, as OCS proposes, none of these current real-world market-limiting characteristics would be represented in the GRID model.

Q. What market capacity methodology was used in the Company's export credit GRID study?

A. The market capacity in the Company's export credit GRID study reflects a four-year average of historical short term firm transactions, by market, month, and hour class (HLH and LLH). In addition, no market capacity limits are applied to the Mid-Columbia or the Palo Verde markets because they are the most liquid market points to which the Company has access. This methodology, and the basis for adopting it, was originally presented in the direct testimony of Mr. Gregory N. Duvall in the Company's 2010 general rate case in Docket No. 10-035-124, lines 209-263, and was also discussed in the direct testimony of Mr. Duvall in the Company's 2013 general rate case in Docket No. 13-035-184. The methodology has been incorporated into the GRID model since that time.

Q. Have the circumstances necessitating market caps in GRID changed dramatically since the Company's 2013 general rate case?

A. No. The Company's GRID modeling in the 2020 general rate case in Docket No. 20-035-04 continues to use the same market capacity methodology adopted previously.

Q. Mr. Hayet suggests that in the absence of recent benchmarking by the Company, the removal of HLH market capacity limits represents a reasonable modeling change.[14] Do you agree?

A. No. Mr. Hayet has presented no evidence that the removal of the HLH market capacity limit results in the GRID model producing a more accurate system dispatch. Because the Company's market capacity limits are based on actual market transactions, the limits are inherently tied to actual conditions. Mr. Hayet's proposal disregards that evidence.

Q. Dr. Milligan implies that EIM prices and forward market prices are equivalent.[15] Is this a reasonable conclusion?

A. No. Price formation in the EIM is different from price formation in forward markets because it occurs shortly prior to delivery, and indeed is the last possible opportunity to monetize generating capacity. In a given interval, capacity on resources without restrictive energy limits that is not required to be held as operating reserves becomes worthless if it held back and not deployed. Under those conditions, an optimal strategy is to bid each resource at its variable cost. In contrast, forward market prices also account for the risk of changes in demand and prices between the time of a transaction and the time of delivery. On a forward basis, the bid price must also compensate for the cost of price changes, and there is significant upside risk to prices, so bids are typically higher than the variable cost of the underlying assets.

Q. Are EIM prices likely to be comparable to the GRID model results?

A. Yes. Most of the avoided energy costs from the Company's GRID study reflect variable

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[14] *See* lines 424-427 of OCS witness Mr. Hayet's Rebuttal Testimony.
[15] *See* lines 244-246 of Vote Solar witness Dr. Milligan's Rebuttal Testimony.

costs of the marginal generating units, which is comparable to expected pricing in EIM as it does not include a risk premium. Avoided market purchases or incremental market sales in GRID would reflect the forward premium of the OFPC, but those market transactions are fairly limited in the Company's GRID study.

Q. What do you conclude with regard to avoided energy costs?

A. The Company has offered two robust methods for determining avoided energy costs. Valuing CG exports using the GRID model captures the effect of expected future changes, notably the near-term solar resource additions to the Company's resource portfolio, but it can't capture the precise relationship between exports and customer load because the exports are based on historical information while the load is based on forecasted, normalized conditions. This relationship can be captured by using historical EIM prices to value the energy from CG exports, but this will not capture future changes in system conditions. This downside to using historical EIM prices is small when paired with an annual update, as the lag between pricing and compensation is not large and changes in value would still flow to customers with CG exports over time. Using EIM prices is also more transparent, since they are publically available and not subject to an array of modeling inputs. Ultimately, either the Company's GRID study or historical EIM prices produces a reasonable estimate of avoided energy costs. Parties have not proposed any avoided energy cost methodologies that would better reflect future conditions, especially over the longer-term.

Line Losses

Q. What objections do parties' raise with regard to the Company's proposal for avoided line losses?

A. Vote Solar witness Mr. Volkmann has proposed that avoided losses include one additional segment of the transmission and distribution ("T&D") system beyond the primary system losses in the Company's proposal, specifically line transformer losses.[16] OCS witness Mr. Hayet agrees that these secondary transformation losses would be avoided.[17]

Q. Are the losses proposed by Mr. Volkmann specific to CG exports?

A. No. The losses proposed by Mr. Volkmann are from the Company's loss study, and reflect the average losses associated with retail load on each of the segments of the T&D system. As a result, the losses are specific to a retail load profile, rather than a CG export profile.

Q. Will CG exports result in incremental losses between the meter of the exporting customer and the meter of another retail customer?

A. Yes. After leaving the exporting customer's meter, exported generation will need to cross that customer's service drop before it can reach a point on the distribution system where power could otherwise be flowing to other customers. This reduces the effective avoided losses associated with CG exports from the level proposed by Mr. Volkmann and supported by Mr. Hayet from approximately 8.621 percent to 8.076 percent.[18] To

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[16] *See* lines 240-252 of Vote Solar witness Mr. Volkmann's Revised Affirmative Testimony.
[17] *See* lines 512-516 of OCS witness Mr. Hayet's Rebuttal Testimony.
[18] *See* Figure 1 (lines 41-43) and lines 110-115 of Vote Solar witness Mr. Volkmann's Rebuttal Testimony. 8.076 percent reflects Mr. Volkmann's proposed loss expansion factor of 1.08621 divided by the service drop loss expansion factor of 1.00504 shown in Mr. Volkmann's Figure 1.

the extent CG exports or other distributed generation resulted in a circuit as a whole becoming a net exporter, additional losses would occur as the exported output was transferred to other circuits or substations.

Q. How does this compare to the Company's proposal?

A. The Company's proposal used a marginal line loss calculation, with values that vary by month and hour of the day. Marginal line losses are highest when load is highest, reaching up to 11.5 percent in the late afternoon in July, and dropping as low as 5.3 percent in the middle of the night in October when load is low. Based on the Company's CG export profile, the avoided losses included in the Company's direct filing amounted to 8.36 percent, which is slightly higher than the level proposed by Mr. Volkmann, after it has been appropriately adjusted for losses on the exporting customer's service drop.

Q. Can the Company's marginal line loss calculation be modified to incorporate avoided line transformer losses and incremental service drop losses?

A. Yes. Rather than using marginal primary losses, a weighted blend of primary and secondary marginal losses can be calculated, consistent with the effective loss rate of 8.076 percent described above. This increases the calculated avoided losses based on the Company's direct filing from 8.36 percent to 9.00 percent. This change results in an average increase in export credit value of $0.07/megawatt-hour ("MWh") based on the Company's direct filing using avoided energy costs calculated in GRID or an increase of $0.13/MWh based on the Company's rebuttal filing alternative using avoided energy costs calculated from historical EIM prices.

Q. What do you recommend with regard to avoided line losses?

A. Incorporating the net impact of avoided line transformer losses and incremental service drop losses in the Company's marginal line loss calculation reasonably accounts for the avoided losses specifically associated with CG exports at this time. It will be appropriate to refine these assumptions in the future, particularly as distributed resources become more prevalent and results in surplus output that requires voltage transformation and transfers to more distant points.

Integration

Q. What objections do parties' raise that are related to the Company's proposal for integration costs?

A. UCE witness Ms. Bowman argues that the aggregate variability of distributed resources is lower than that for individual sites.[19] Vivint Solar witness Dr. Worley argues that it is inappropriate to assess charges to behind-the-meter resources because changes associated with CG exports are indistinguishable from changes in load.[20] Vote Solar witness Dr. Milligan argues that integration costs are discriminatory because they ignore integration requirements imposed by other resource types.[21] Dr. Milligan also argues that CG resources can provide the ancillary services that are included in integration costs.[22]

Q. Are the Company's solar integration costs based on the variability of individual utility-scale solar assets?

A. No. The Company's Flexible Reserve Study for the 2019 IRP details how it determines

[19] *See* lines 349-350 of UCE witness Ms. Bowman's Rebuttal Testimony.
[20] *See* lines 321-342 of Vivint Solar witness Dr. Worley's Rebuttal Testimony.
[21] *See* lines 336-338 of Vote Solar witness Dr. Milligan's Rebuttal Testimony.
[22] *See* lines 355-358 of Vote Solar witness Dr. Milligan's Rebuttal Testimony.

regulation reserve requirements sufficient to account for the aggregate variation in solar, wind, load, non-variable energy resources that do not follow dispatch signals. Because variations in these broad categories do not occur simultaneously, the total requirement is lower than what would be necessary to reliably compensate for the variations in each of these classes on their own. The Company's solar integration costs thus reflect not only the diversity inherent from considering the aggregate requirements of approximately 1,000 MW of solar resources, but they also consider the diversity from approximately 2,750 MW of wind resources, approximately 2,000 MW of non-variable energy resources, and approximately 10,000 MW of load.[23]

Q. How does the variability of CG exports compare to that of the utility-scale solar assets on the Company's system?

A. The Company has intra-hour data available for both its aggregate utility-scale solar assets and its aggregate CG exports under Schedule 136. To provide a measure of the variability of these two data sources, the Company calculated the absolute value of the difference between the actual output in each 15-minute interval and the average output across the entire clock-hour that 15-minute interval is in. Summing all of the 15-minute deviations and dividing by the total actual output provides a percent error metric such that the two data sources can be compared. The utility-scale solar assets had a percent error value of 7.2 percent, while the CG exports had a slightly higher percent error value of 8.8 percent.

[23] See Table F.9 of Appendix F in Volume II of the Company's 2019 IRP.

Q. Is it reasonable for the variation in CG exports to be higher than for utility-scale solar resources?

A. Yes. As previously discussed, the Company has a large number of utility-scale solar resources on its system, so it is already incorporating benefits from aggregation in its integration cost analysis. In addition, the utility-scale solar resource data reflects the entirety of these resource's output, whereas CG exports only reflect output in excess of customer load. By removing on-site customer load, the relative amount of variability in each increment of CG exports may be increased, relative to CG production.

Q. Is Dr. Worley correct that behind-the-meter resources are different from utility-scale resources, because their effects are indistinguishable from changes in load?

A. No. For practical purposes, in actual operations <u>all</u> resource output is indistinguishable from changes in load. The Company's proposed integration costs reflect the cost of holding back flexible capacity to ensure that the area control error ("ACE") for PacifiCorp's balancing authority areas ("BAAs") remains within bounds specified by NERC standard BAL-001-2.[24] Area control error represents the net of the unscheduled transfers into PacifiCorp's BAA and out of PacifiCorp's BAA, so it reflects the difference between all of the load in the BAA and all of the generation in the BAA. While internal transmission constraints could potentially require additional output from within a specific area in certain circumstances, the Company's integration costs do not account for the extra costs that the location of the need within the Company's BAA might impose.

[24] NERC Standard BAL-001-2 – Real Power Balancing Control Performance: www.nerc.com/files/BAL-001-2.pdf

Q. Are the Company's integration costs discriminatory, as suggested by Dr. Milligan?

A. No. As previously discussed, the Company's Flexible Reserve Study accounts for the aggregate variation in solar, wind, load, and non-variable energy resources that do not follow dispatch signals. This captures the benefits of diversity within and among each of these categories. To the extent that solar resources are replacing wind resources, accounting for differences in the integration costs being added for solar and those being removed for wind would be relevant.

Q. Are there any integration costs associated with the resources Dr. Milligan uses to derive his proposed avoided energy costs?

A. No. Dr. Milligan's avoided energy costs are based on hourly market transactions priced using the Company's OFPC. The Company's OFPC represents a firm transaction, with no imbalance or uncertainty across the hour, so integration costs would not apply.

Q. Are there any integration costs associated with the resources identified in the GRID-model forecast the Company proposed using to derive avoided energy costs?

A. No. The GRID-model forecast identifies energy costs from the marginal dispatchable resources, primarily coal and gas, along with changes in hourly market transactions. Dispatchable coal and gas resources are suppliers of the regulation reserves underlying the Company's integration costs. While individual units may not perform exactly as intended under every circumstance, the aggregate performance of the dispatchable resource class as a whole must be sufficient to adequately compensate for the variations in load and resources on the system. Just as wind and solar resources benefit from a diverse portfolio, the performance of dispatchable resources is also judged as a portfolio. In that regard, dispatchable resources do not contribute to the imbalance of the system, and would not incur integration charges such as those proposed by the Company.

Q. Is the Company's proposed interpretation of integration costs universally applicable?

A. No. Dr. Milligan notes that the definition of "integration cost" is not standard.[25] The Company's definition only includes the cost of setting aside flexible capacity that may need to be called upon within an hour to maintain the load and resource balance, and not the cost of deploying that flexible capacity. Under a more expansive view of "integration cost", such as one that accounted for intra-hour variations in energy output, charges for individual dispatchable resources based on their ability to precisely follow a dispatch target would be reasonable.

Q. Are integration costs still appropriate under the historical EIM pricing alternative the Company offered in its rebuttal testimony?

A. Yes. The historical EIM pricing alternative uses 15-minute EIM prices that are based on forecasts using expected system conditions as of 37.5 minutes prior to the operating interval. These prices are applied to the average actual CG exports in each 15-minute interval. If a resource perfectly matched its expected output for every 15-minute interval, not just on average, but across the entire interval, then it would not result in imbalance and would not require other resources to compensate for its deviations. As previously discussed, CG exports vary significantly across each hour, and it follows

[25] *See* lines 340-343 of Vote Solar witness Dr. Milligan's Rebuttal Testimony.

that they also vary across each 15-minute interval. The percent error values previously discussed also do not account for the difference between forecasted exports and actual exports, and other resources would be required to compensate for that difference as well. As a result, integration costs for CG exports are still appropriate.

Q. Dr. Milligan states that the 2019 IRP "assumes that all conventional resources follow signals perfectly."[26] Do you agree with this interpretation?

A. No. Dr. Milligan cites to the table of Supply-side Resource Options in the 2019 IRP, which identifies cost and performance assumptions for resources that are available for selection. Within the table, integration cost is only assigned to wind and solar resources. As discussed above, dispatchable resources in aggregate must maintain an adequate balance between loads and resources. Individual resources may vary at times while still contributing to the performance of the aggregate. This is analogous to the diversity in wind and solar resource output captured in the Company's integration cost assumptions. Applying an integration cost of $0/MWh to dispatchable resources is thus reasonable in this context.

Q. Dr. Milligan indicates that "cycling costs" are often included in the integration costs assigned to renewable resources.[27] Did the Company include "cycling costs" in its wind and solar integration costs?

A. Not explicitly. The Company's integration costs represent only the cost of maintaining an incremental supply of operating reserves to maintain the load and resource balance. It is possible that the incremental operating reserve requirement could result in units cycling differently than they otherwise would have and the net impact of those changes

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[26] *See* lines 381-385 of Vote Solar witness Dr. Milligan's Rebuttal Testimony.
[27] *See* lines 433-468 of Vote Solar witness Dr. Milligan's Rebuttal Testimony.

is included in the integration cost; however this effect is much more limited than that described by Dr. Milligan because it does not account for cycling changes related to the addition of wind and/or solar generation in total, just the associated operating reserve requirement, which is much smaller. In the Company's 2017 IRP, the wind and solar integration cost included the cost of sub-optimal gas plant commitment based on day-ahead forecasts, rather than perfect foresight of actual output that is otherwise modeled. This component was minimal and was not included in the 2019 IRP integration cost values that the Company has proposed applying in this proceeding.

Q. What do you recommend with regard to integration costs?

A. The integration costs in the 2019 IRP account for the contribution of load and all different types of resources to the operating reserve requirements from which the integration costs are derived, so they does not discriminate against wind or solar resources. The variation in CG exports is comparable to that of the Company's diverse solar resource portfolio that solar integration costs are based upon, so applying the same integration cost is reasonable. Therefore the Commission should approve the Company's proposal to include solar integration costs from the 2019 IRP in the export credit value.

Grid Services

Q. Do parties advocate for compensation for grid services provided via smart inverters?

A. Yes. UCE[28] and Vivint Solar[29] advocate for grid services compensation in the export credit price.

[28] *See* lines 687-698 of UCE witness Ms. Bowman's Rebuttal Testimony.
[29] *See* lines 499-506 of Vivint Solar witness Dr. Worley's Rebuttal Testimony.

Q. Are smart inverters better than other inverters?

A. Yes. The most basic enhancement smart inverters provide is low-voltage ride through. When system conditions deteriorate, and voltage or frequency drops outside the normal range, inverters without "smart" features may trip offline, exacerbating a bad situation, as any generation that is removed from the grid will further reduce voltage and frequency, potentially triggering other generators to trip offline as well. Under these conditions, generation needs to be replaced within seconds or under-frequency load shedding may be necessary to maintain grid stability. A smart inverter can continue to operate through these conditions, and would not contribute to a cascading failure.

Q. Does the Company's export credit value include any costs to account for the risk posed by inverters without low-voltage ride through capability?

A. No. As a result, while inverters with low-voltage ride through capability are better than inverters without that capability, no incremental compensation is appropriate for that feature relative to the Company's current proposals. If anything, resources without low-voltage ride through capability should incur additional charges that would result in lower export credit compensation.

Q. Can smart inverters provide other grid services?

A. Yes. The other grid services a smart inverter can provide generally fall into one of two categories: increasing output or reducing output in response to system conditions.

Q. Please describe how smart inverters can provide grid services by increasing output in response to system conditions.

A. Operating reserves, "up" regulation, and under-frequency response all require increases in output. As Dr. Milligan states, "bi-directional dispatch and regulation can be provided only if the resource is "pre-dispatched" below its maximum generation."[30] For example, a resource must forgo energy output in order to provide operating reserves. This would only be economic if the value of operating reserves exceeds the value of energy during an interval, and typically this would only occur when the energy price is below zero. When energy prices are below zero, the value of incremental operating reserves is also likely to be zero. The Company's 2019 IRP assumed that all proxy wind and solar resource additions would be capable of downward dispatch and could provide reserves under these conditions, and recent non-QF wind and solar power purchase agreements also allow for this type of control. As a result, an excess of operating reserve capability is likely to be available such that the cost of operating reserves is unlikely to exceed the energy price, or zero, if the energy price is negative.

Q. Please describe how smart inverters can provide grid services by decreasing output in response to system conditions.

A. Maintaining the load and resource balance requires both upward and downward adjustments. "Down" regulation and over-frequency response both require decreases in output, and may be necessary if a large load is suddenly disconnected, or if generation resources unexpectedly increase their output. A smart inverter can support reliable system operation by curtailing exports to the grid, potentially to zero, in response to those system conditions. Because of the downward dispatch capability of the Company's existing and contracted portfolio of wind and solar resources, and the expected downward dispatch capability of future wind and solar additions, maintaining downward flexibility is not expected to result in a cost on an ongoing basis. This is in

[30] *See* lines 388-390 of Vote Solar witness Dr. Milligan's Rebuttal Testimony.

contrast with upward flexibility, where operating reserves are often held on resources that would otherwise be providing economic generation. However, when marginal prices drop below zero, reductions in generation can produce incremental value.

Q. Is curtailment expected to provide significant benefits?

A. No. Based on historical 15-minute EIM prices, there were 601 15-minute intervals with negative prices between October 2018 and September 2019. While this represents less than 2 percent of the hours in a year, approximately 6 percent of the CG exports were delivered in those intervals, which indicates that CG exports can have an outsized impact during over-supply conditions. However, most of those intervals had prices between -$1.00 and zero, such that the benefits of curtailment are small. As a result, perfect curtailment during negatively priced intervals would increase the energy value of CG exports by less than 1 percent. To achieve this small gain, a control system that could automatically dispatch CG exports up and down at short notice would be necessary. This would require investments beyond just the installation of a smart inverter. While the Company is open to pursuing measures that provide cost-effective service to customers, these control systems are not expected to be in place in the near term and the long-term cost effectiveness of such a potential smart inverter dispatch program is unproven.

Q. What time frame are grid services likely to be provided on?

A. Control systems necessary to dispatch CG exports are likely to be operated at intervals of less than fifteen minutes. The EIM includes balancing and dispatch every five minutes, and dispatch of the Cool Keeper program occurs in less than a minute.

Q. What do you recommend with regard to grid services?

A. The Company's proposed export credit rates reasonably account for the value provided under the proposed Schedule 137 program and the value of the grid services CG exports are likely to be able to provide is currently small. Any grid services that could be provided would require program modifications beyond what is currently proposed, and thus would not represent incremental value at this time. To the extent program modifications enabling the provision of grid services are made, the associated benefits should be addressed in the annual export credit update at that time.

Capacity

Q. What additional issues do parties' raise that are related to the capacity value?

A. UCE witness Ms. Bowman claims that distributed solar is modeled in the Company's IRP as a reduction to system peak load that defers procurement of capacity resources.[31] Vote Solar witness Dr. Milligan makes a variety of arguments related to the capacity value of CG solar.[32]

Q. Do you have any comments related to the modeling of distributed solar in the Company's IRP?

A. Yes. The Company does not dispute that distributed solar can reduce the need for other capacity resources. While the Company's 2019 IRP evaluated portfolios based on a range of projections for customer generation, it did not evaluate whether those outcomes were cost-effective. As a result, it may well be the case the utility-scale solar can provide equivalent capacity and achieve lower overall system costs than distributed solar. The Company's 2019 IRP included Utah utility-scale solar resources with storage

[31] *See* lines 391-414 of UCE witness Ms. Bowman's Rebuttal Testimony.
[32] *See* lines 575-758 of Vote Solar witness Dr. Milligan's Rebuttal Testimony.

capability at a real-levelized cost of just $32/MWh in 2024. Advantages of such a utility scale resource, relative to CG solar exports, include sun tracking, full curtailment rights, and highly flexible storage capacity. The CG exports being valued in this proceeding have a small amount of avoided losses in their favor, relative to a utility-scale asset, but are reduced by customer usage, especially during periods of peak demand, and do not provide the other enhancements of the utility-scale asset. As a result, a reasonable CG export value should not even approach the cost of that utility-scale solar asset.

Q. Do you have any other comments related to Dr. Milligan's rebuttal testimony?

A. Yes. Most of the topics raised in Dr. Milligan's rebuttal testimony were addressed in my rebuttal testimony, so I will not repeat that discussion here. The crux of Dr. Milligan's position is summarized by the statement that "(g)enerally, *any* additional MW of generation during a time of loss-of-load ("LOL") risk will have a positive capacity contribution."[33]

Q. Do you agree with Dr. Milligan's characterization of capacity contribution?

A. Yes. Any increase in supply or reduction in load during a period with loss-of-load events is likely to reduce the risk and/or magnitude of outages.

Q. Are CG exports likely to be significant during periods with a risk of loss-of-load events?

A. No. Analysis provided in my rebuttal testimony identified the capacity contribution of CG exports based on the methodology used in the 2019 IRP and based on historical loads, net of existing and contracted utility-scale solar resources in Utah. Both of these

[33] *See* lines 617-618 of Vote Solar witness Dr. Milligan's Rebuttal Testimony. Italics in original.

methods produced capacity contribution values for CG exports that were under 5 percent.[34] Neither methodology fully accounts for the expected availability of CG exports during extreme peak-producing temperatures where loss-of-load risk is highest, as increases in a customer's own loads would likely reduce or eliminate CG exports under those conditions. As several witnesses noted, under the Company's proposed Schedule 137 program, customers would be incented to use as much of their CG production as possible to avoid retail charges, rather than exporting and receiving a lower level of compensation. This dynamic could result in lower CG exports during peak conditions and lower capacity contributions in the actual Net Billing program, relative to the CG export profiles used in the capacity contribution analysis, since existing customer generators have much less incentive to align their production and consumption.[35]

Q. Does the presence of CG exports during periods with a risk of loss-of-load events necessitate compensation for avoided capacity costs?

A. No. The Company does not compensate QFs for capacity if they do not commit to sell their output to the Company and meet availability or output guarantees. A variable energy resource, such as wind or solar, can meet these requirements and receive compensation for capacity despite not being able to provide specified quantities in particular hours. In contrast, a QF generator that opts to use its output for its own requirements first and does not provide availability and output guarantees does not receive compensation for capacity, even though it may deliver during periods with a

[34] See lines 707-748 of Company witness Mr. MacNeil's Rebuttal Testimony.
[35] Prices for export credits under Schedule 136 - Transition Program for Customer Generators were set at 90 percent of average retail energy charges for Schedules 1, 2, and 3 and 92.5 percent for all other schedules.

risk of loss-of-load events. The CG exports under the proposed Schedule 137 program are analogous to the latter circumstance.

Q. What do you conclude with regard to the capacity value of CG exports?

A. Because of the significant penetration of solar resources in the Company's portfolio, the capacity value of CG exports is small, and likely to diminish in the future as additional solar resources are added. The capacity value of CG exports is likely to be further reduced during extreme peak-producing temperatures where loss-of-load risk is highest because CG exports are net of a customer's own load and the proposed Schedule 137 program provides an incentive for customers to use their CG production, rather than exporting it. Given the small contribution and the fact that the system as a whole only has a secondary claim to the output under the Schedule 137 proposal, the Company does not consider including compensation for capacity in the export credit rate to be appropriate. If capacity value was to be included in the compensation for CG exports, the resulting export credit rates should be lower than what the Company could pay for utility-scale solar assets, in light of the relative benefits of utility-scale solar versus CG exports.

Annual Updates

Q. What issues do parties raise with regard to the Company's proposal to update the export credit rate annually?

A. UCE witness Ms. Bowman, Vivint Solar witness Dr. Worley, and Vote Solar witness Dr. Berry oppose annual export credit updates.

Q. Dr. Berry indicates that no other residential customers are subject to rates that change on an annual basis.[36] Is this accurate?

A. No. All residential customers are subject to annual updates to Schedule 94, the Energy Balancing Account, Schedule 98, the Renewable Energy Credit Balancing Account, and Schedule 193, the Demand Side Management Cost Adjustment. The Company has proposed including export credit rate payments in the accounts used for other purchased power expenses, which are included in the Energy Balancing Account and trued-up annually via Schedule 94.

Q. Are any other residential customers subject to rates that are guaranteed to be fixed for twenty years?

A. No. The closest analog is Schedule 135 and Schedule 136, which will provide fixed credits (kilowatt-hour ("kWh") for kWh under Schedule 135) or rates (under Schedule 136) for the next 12-15 years. However, other residential rate schedules do not provide that level of certainty.

Q. Dr. Berry suggests that annual updates are likely to be contentious if they are based on the GRID model.[37] Has the Company offered an alternative?

A. Yes. In my rebuttal testimony, I offered an alternative proposal to use historical EIM prices to set export credit rates for the upcoming year. Because EIM prices are public, this would reduce the burden on parties that are reviewing the results. While these prices are backward-looking, they rely on relatively recent information and should provide an accurate representation of export credit value over time.

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[36] *See* lines 85-86 of Vote Solar witness Dr. Berry's Rebuttal Testimony.
[37] *Ibid*.

Q. Will the future replacement of the GRID model dramatically change the way in which the Company calculates the export credit rate under the Company's proposed methodology?

A. No. Future models will share the majority of the characteristics of the GRID model, in that they will include the Company's resource portfolio, loads, and transmission rights. While some of the details of how those inputs fit together will change, the essential inputs and basic principle of least-cost dispatch will continue to apply, so the marginal cost during hours when CG exports are expected to occur is unlikely to change dramatically when moving from GRID to a future model. Significant changes are possible as a result of input changes, such as changes in market prices or loads, the implementation of greenhouse gas charges, or resource retirements or additions, but those changes would all have comparable effects within the GRID model.

Q. Dr. Berry suggests that annual updates will shift risk to CG customers.[38] What is the alternative?

A. The alternative is that any risk associated with changes in the actual value of export credits relative to the approved rate will be borne by non-participating customers. Dr. Berry's aversion to accepting the risks of annual updates and claims of harm are indications that the actual value of export credits may not be sustained at the levels proposed by Vote Solar over time.

Q. Is value for the entirety of a customer's CG production subject to the proposed annual updates to export credit rates under Schedule 137?

A. No. The Company's export credit rates under the proposed Schedule 137 do not apply

[38] *See* lines 734-736 of Vote Solar witness Dr. Berry's Rebuttal Testimony.

to CG production that offsets a customer's onsite demand. The value of any CG production consumed onsite avoids the cost of retail rates, which is the same as under Schedules 135 and 136. As a result, the value of any CG production consumed onsite will not be impacted by the annual update to export credit rates.

Q. What do you recommend with regard to the frequency of updates for the export credit rate?

A. Many conditions can cause the export credit value to increase or decrease over time, and the direction and magnitude of those changes is uncertain. Annual updates will ensure that the export credit rate remains accurate and that non-participating customers do not bear the risk of changes in value over time.

On-Peak and Off-Peak Definition

Q. Do parties raise issues related to the Company's proposed on-peak and off-peak definitions for Schedule 137?

A. Yes. Vote Solar witnesses Mr. Constantine and Dr. Berry each raise concerns related to the Company's on-peak and off-peak definitions.

Q. Vote Solar witness Mr. Constantine suggests that customers cannot respond effectively to the proposed time-varying export credit rate in intervals less than one hour and that the on-peak to off-peak price ratio is insufficient to change behavior.[39] Is the intent of differentiated export credit rates to drive customer behavior?

A. No. The intent of differentiated export credit rates is to accurately and fairly provide compensation for CG exports. While customer generation mostly consists of rooftop

[39] *See* lines 322-334 of Vote Solar witness Mr. Constantine's Rebuttal Testimony.

solar, some customers may be in a position to use other technologies, such as wind, hydro, or biogas. The differentiated rate more fairly compensates resources and consumption patterns that result in different export profiles, without requiring any change in the behavior or consumption of individual customers.

Q. Vote Solar witness Dr. Berry states that "Appropriate compensation can be accomplished with a single rate."[40] Do you agree?

A. No. The Company anticipates that the diverse consumption and production patterns of Schedule 137 participants will result in varied CG export profiles and that a single rate would result in some customers being over-compensated while others would be under-compensated. While the four rates (winter/summer and on/off-peak) in the Company's proposal will not ensure perfectly accurate compensation for every customer, they provide a meaningful differentiation with limited administrative burden.

Q. Vote Solar witness Dr. Berry states that "RMP has provided no support for the relative magnitudes of the proposed time-varying rates."[41] Is this accurate?

A. No. The Company's direct testimony and associated non-confidential workpapers provide all of the details supporting its proposed time-varying rates.[42][43] The relative magnitudes of the rates for each time period reflect the relative magnitude of historical EIM prices across the time periods when CG exports occur.

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[40] *See* lines 49-50 of Vote Solar witness Dr. Berry's Rebuttal Testimony.
[41] *See* lines 49-50 of Vote Solar witness Dr. Berry's Rebuttal Testimony.
[42] *See* lines 189-207 of RMP witness Mr. MacNeil's Direct Testimony.
[43] The calculations supporting the relative magnitude between the proposed on-peak and off-peak rates are in rows 85-86 of sheet "Export Credit" in RMP Workpapers DJM 1 – Export Credit Summary By Element, filed on Feb. 3, 2020. Available online at: https://pscdocs.utah.gov/electric/17docs/1703561/311969RMPWrkprsDJM1ExprtCrdtSmryElmnt2-3-2020.xlsx (accessed 9/2/2020).

Q. Vote Solar witness Dr. Berry suggests that the four-hour on-peak duration proposed by the Company is an arbitrary choice.[44] Is there any basis for the Company's proposal?

A. Yes. The Company's testimony and workpapers, referenced above, demonstrate how the Company identified its proposed on-peak periods based on rankings of historical EIM pricing. That said, other definitions are possible. For example, using the two highest priced hours would result in an on-peak period of 6:00 p.m. to 8:00 p.m. Mountain Prevailing Time ("MPT") in both the summer and winter, eliminating the late afternoon portion of on-peak in the summer and the morning portion of on-peak from the Company's proposal. While simpler, the two-hour window fails to capture monthly variation, as at least one of the top two highest-priced hours is in the morning in five of eight winter months, and in the late afternoon in two of four summer months.

Similarly, a six-hour duration results in an on-peak period that includes hours with below average prices. For example, the sixth-ranked winter hour is 5:00 p.m. to 6:00 p.m. MPT, and the prices for that hour are approximately 38 percent below the monthly average in March and April, so including it in the "high-priced" hours is illogical. While alternative on-peak and off-peak definitions are possible, changes would not impact the expected total export credit compensation, and would have a relatively limited impact on individual customer generators. The Company's proposal provides a reasonable differentiation between periods of higher and lower value while retaining a relatively simple structure.

[44] *See* lines 255-257 of Vote Solar witness Dr. Berry's Rebuttal Testimony.

Q. Vote Solar witness Dr. Berry criticizes the Company's proposed on-peak/off-peak definition for not aligning with previous methodologies based on system and distribution coincident peaks.[45] How do you respond?

A. The Company has previously employed methodologies for allocating the costs of serving load based on system and distribution coincident peaks. All customers share the costs of the resources, equipment, facilities, and personnel that are necessary to ensure they receive safe and reliable electrical service. It is reasonable to allocate some of those costs based on system and distribution peaks. Other of those costs are allocated based on energy consumption, customer count, and other factors. Those factors are fundamentally different from differentiating the value of an incremental resource, as represented by the CG exports at issue in this proceeding. An incremental resource is judged not based on the characteristics of the portfolio it is being added to, but rather based on the characteristics of the incremental costs it avoids. Because the Company's system load peaks no longer coincide with either the periods of the highest energy prices or the periods of the highest risk of loss of load events, they do not provide a reasonable basis for differentiating the value of incremental CG exports.

Q. Vote Solar witness Dr. Berry suggests that the on-peak/off-peak definition will be subject to change every year.[46] How do you respond?

A. The Company does not intend to modify the on-peak and off-peak definitions annually. As noted by OCS witness Mr. Hayet, small changes in these definitions should not have a material impact on the total compensation to solar customers.[47] The Company also

[45] *See* lines 265-283 of Vote Solar witness Dr. Berry's Rebuttal Testimony.
[46] *See* lines 682-685 of Vote Solar witness Dr. Berry's Rebuttal Testimony
[47] *See* lines 237-242 of OCS witness Mr. Hayet's Rebuttal Testimony

does not anticipate that the highest value periods that are driving the on-peak definition will change dramatically from year to year. As a result, the limited impact on the results would not justify the administrative burden and potential customer confusion associated with changing the on-peak and off-peak definition every year. The Company agrees that these definitions could be modified in the future, but would suggest that it be taken up as part of a general rate case, so that alignment with other time-of-use rates can be considered along with other factors.

Q. Vote Solar witness Dr. Berry suggests that the Company's proposal will incent CG customers to install battery storage while failing to align incentives and outcomes that benefit both the CG customer and the grid.[48] How do you respond?

A. Several parties in this proceeding note that customer-sited battery storage has the potential to provide additional grid benefits. The Company's 2019 IRP also identified that adding battery storage to solar resources was more cost-effective than solar resources on their own, so there is a precedent for encouraging the pairing of solar and storage.[49] As I previously discussed, the grid services that would maximize the potential benefits of customer-sited batteries would require program modifications and control systems beyond those in the Company's proposal. However, a customer-sited battery program could operate in parallel with the proposed Schedule 137, much like Cool Keeper does today, so it would not be precluded by the outcome of this proceeding.

Dr. Berry's concern that the Company's proposed export credit program incents battery storage but doesn't capture all possible benefits is also misplaced in light of

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[48] *See* lines 319-334 of Vote Solar witness Dr. Berry's Rebuttal Testimony

[49] See PacifiCorp's 2019 IRP, Volume I, Chapter 7, page 199.

Vote Solar's proposed export credit program. Vote Solar is advocating for export credit programs with a strong disincentive for battery storage through either a return to net metering or the implementation of a single export credit rate that is in excess of the retail rate.[50] In either scenario, the timing of exports would be irrelevant, and the less than perfect efficiency of battery storage would result in a net reduction in compensation whenever battery storage was charged and discharged. As a result, Vote Solar's proposals would actively discourage customers from participating in a customer-sited battery program that provide greater benefits for CG customers and the grid.

Q. What do you recommend with regard to the on-peak and off-peak definition for the export credit rate?

A. The on-peak and off-peak definition does not change the effective compensation for the average export profile; however, distinguishing between on-peak and off-peak periods helps ensure that the compensation paid to customers with different export profiles is consistent with the value they provide. The Company's proposal for a four-hour on-peak period differentiated by summer and winter seasons provides a reasonable differentiation between periods of higher and lower value while retaining a relatively simple structure. Parties' proposals to eliminate differentiated rates would fail to account for the real differences in the value of CG exports across time and should be rejected.

[50] *See* lines 716-739 of Vote Solar witness Mr. Constantine's Rebuttal Testimony.

Conclusion

Q. What is your recommendation for the Commission?

A. The Company has presented export credit rates based on the approved methodology for forecasting qualifying facility avoided costs in Exhibit RMP___(DJM-1SR) and based on historical EIM prices in Exhibit RMP___(DJM-2SR). While a forecast is specific to the rate effective period, historical EIM prices are more transparent for parties to review, and either method provides a reasonable basis for setting time-differentiated export credit rates that are to be updated annually. The Company recommends that the Commission approve the Schedule 137 export credit rates and structure as filed by the Company and require annual updates to ensure avoided costs continue to align with the compensation provided for CG exports.

Q. Does this conclude your surrebuttal testimony?

A. Yes.

Rocky Mountain Power
Exhibit RMP___(DJM-1SR)
Docket No. 17-035-61
Witness: Daniel J. MacNeil

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

Exhibit Accompanying Surrebuttal Testimony of Daniel J. MacNeil

Approved Methodology for Forecasting QF Avoided Costs

September 2020

PacifiCorp
State of Utah
Export Credit Summary by Element

	On-Peak				Off-Peak				Average*
Month	**Energy $/MWh**	**Losses $/MWh**	**Integration $/MWh**	**Total $/MWh**	**Energy $/MWh**	**Losses $/MWh**	**Integration $/MWh**	**Total $/MWh**	**Total $/MWh**
1/1/2021	$24.82	$1.76	($0.27)	$26.32	$15.27	$1.08	($0.16)	$16.18	$16.25
2/1/2021	$36.62	$1.88	($0.39)	$38.11	$15.70	$0.81	($0.17)	$16.34	$16.56
3/1/2021	$30.09	$1.67	($0.32)	$31.44	$12.83	$0.71	($0.14)	$13.41	$14.01
4/1/2021	$22.45	$1.14	($0.24)	$23.35	$9.95	$0.51	($0.11)	$10.34	$11.11
5/1/2021	$16.43	$1.00	($0.18)	$17.26	$11.39	$0.70	($0.12)	$11.97	$12.30
6/1/2021	$19.82	$1.45	($0.21)	$21.05	$13.14	$0.96	($0.14)	$13.96	$14.33
7/1/2021	$30.05	$3.10	($0.32)	$32.83	$19.63	$2.03	($0.21)	$21.45	$21.91
8/1/2021	$33.21	$2.70	($0.36)	$35.55	$17.14	$1.39	($0.18)	$18.35	$18.98
9/1/2021	$19.72	$1.43	($0.21)	$20.93	$14.93	$1.08	($0.16)	$15.85	$16.01
10/1/2021	$25.44	$1.63	($0.27)	$26.80	$13.11	$0.84	($0.14)	$13.81	$13.95
11/1/2021	$22.55	$1.51	($0.24)	$23.82	$13.73	$0.92	($0.15)	$14.50	$14.73
12/1/2021	$26.46	$1.94	($0.28)	$28.11	$16.56	$1.22	($0.18)	$17.59	$17.69
Annual*	$22.90	$1.59	($0.25)	$24.24	$14.11	$1.01	($0.15)	$14.98	$15.33
Summer*	$24.66	$2.04	($0.26)	**$26.44**	$16.01	$1.34	($0.17)	**$17.18**	$17.54
Winter*	$21.49	$1.23	($0.23)	**$22.50**	$12.67	$0.77	($0.14)	**$13.30**	$13.65

Definitions:

On-Peak **Summer:** June through September - 4pm - 8pm
Winter: October through May - 7am - 9am & 6pm - 8pm
All Year: Monday - Friday, excluding Holidays

Off-Peak All other, including all day on weekends and holidays

All times are in Mountain Prevailing Time

* Average values reflect delivery based on historical average export profile

Rocky Mountain Power
Exhibit RMP___(DJM-2SR)
Docket No. 17-035-61
Witness: Daniel J. MacNeil

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

Exhibit Accompanying Surrebuttal Testimony of Daniel J. MacNeil

Based on Historic EIM Prices

September 2020

PacifiCorp
State of Utah
Historical Export Energy Value Summary by Element

Month	On-Peak Energy $/MWh	On-Peak Losses $/MWh	On-Peak Integration $/MWh	On-Peak Total $/MWh	Off-Peak Energy $/MWh	Off-Peak Losses $/MWh	Off-Peak Integration $/MWh	Off-Peak Total $/MWh	Average* Total $/MWh
10/1/2018	$32.52	$2.79	($0.24)	$35.06	$25.02	$2.11	($0.19)	$26.94	$27.05
11/1/2018	$33.97	$2.88	($0.26)	$36.60	$27.99	$2.34	($0.21)	$30.12	$30.72
12/1/2018	$33.27	$2.97	($0.25)	$35.99	$28.42	$2.49	($0.21)	$30.69	$30.92
1/1/2019	$27.90	$2.54	($0.21)	$30.23	$24.38	$2.15	($0.18)	$26.35	$26.54
2/1/2019	$42.28	$3.72	($0.32)	$45.68	$29.43	$2.48	($0.22)	$31.69	$32.36
3/1/2019	$34.51	$2.87	($0.26)	$37.13	$17.25	$1.38	($0.13)	$18.50	$19.23
4/1/2019	$19.10	$1.52	($0.14)	$20.49	$13.02	$1.01	($0.10)	$13.94	$14.34
5/1/2019	$16.64	$1.35	($0.12)	$17.87	$10.22	$0.86	($0.08)	$11.00	$11.52
6/1/2019	$39.81	$4.08	($0.30)	$43.59	$17.02	$1.60	($0.13)	$18.49	$19.60
7/1/2019	$26.57	$3.27	($0.21)	$29.64	$22.87	$2.56	($0.18)	$25.25	$25.43
8/1/2019	$32.41	$3.74	($0.25)	$35.91	$24.99	$2.65	($0.19)	$27.45	$27.74
9/1/2019	$29.60	$2.94	($0.23)	$32.31	$22.67	$2.07	($0.17)	$24.57	$24.81
Annual*	$28.15	$2.65	($0.21)	$30.58	$20.11	$1.84	($0.15)	$21.81	$22.22
Summer*	$33.14	$3.60	($0.25)	**$36.48**	$21.56	$2.18	($0.16)	**$23.58**	$24.06
Winter*	$25.55	$2.15	($0.19)	**$27.50**	$18.98	$1.58	($0.14)	**$20.42**	$20.81

Definitions:

On-Peak — **Summer:** June through September - 4pm - 8pm
Winter: October through May - 7am - 9am & 6pm - 8pm
All Year: Monday - Friday, excluding Holidays

Off-Peak — All other, including all day on weekends and holidays

All times are in Mountain Prevailing Time

* Average values reflect delivery based on historical average export profile

Rocky Mountain Power
Docket No. 17-035-61
Witness: Jacob S. Barker

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

Surrebuttal Testimony of Jacob S. Barker

September 2020

Q. Are you the same Jacob S. Barker who filed rebuttal testimony in this proceeding?

A. Yes.

Purpose of Surrebuttal Testimony

Q. What is the purpose of your surrebuttal testimony?

A. My surrebuttal testimony responds to arguments and recommendations raised in rebuttal testimony submitted on July 15, 2020 related to “wear-and-tear” of distribution equipment and advanced inverters (also known as smart inverters). Specifically, I respond to rebuttal testimony submitted by Vote Solar witness Mr. Curt Volkmann.

Distribution Equipment “Wear-and-Tear”

Q. Do you agree with Mr. Volkmann’s conclusion that there is no evidence Rocky Mountain Power is experiencing “wear-and-tear” of distribution equipment[1]?

A. No. The Company has conducted studies and made reasonable assumptions concerning the wear and tear of distribution equipment caused by customer generation. Consider a single phase regulator, which controls voltage for the system that is downstream of it with three essential settings; a set point, a bandwidth and a delay.[2] These settings determine when and how the voltage regulator will mechanically change taps within the device. The set point is used to direct the regulator to what level it should regulate or hold voltage. A typical setting is 123 volts on a 120 volt base. The bandwidth determines how far the voltage can deviate from the set point before a mechanical operation is necessary to regulate the voltage back

[1] *See* lines 116-160 of Vote Solar witness Mr. Volkmann Rebuttal Testimony.

[2] The Company provided a user manual for a single-phase regulator to Vote Solar in discovery to explain its operation.

to the set point. A typical bandwidth setting is 2.0 volts, meaning in this example the voltage can vary between 122.0 and 124.0 volts before a mechanical operation is called to move the voltage back to within the bandwidth. The delay setting simply tells the regulator how long the voltage can remain outside the bandwidth before it operates, typically 60 seconds.

Mr. Volkmann acknowledges customer generation can raise circuit voltages.[3] As demonstrated in the explanation of the operation of the voltage regulator, the voltage only needs to be raised by 1.0 volt in a typical setting scenario in order to cause a mechanical operation to occur.

It is perfectly reasonable to assume the variability of customer generation can raise and lower circuit voltages in excess of typical bandwidth settings, thus causing additional mechanical operations, or “wear-and-tear” on the regulator. In fact, the Company has modeled a circuit in the Huntsville, Utah area and concluded the voltage change that can occur due to customer generation is 2.0 volts at a line regulator location. This is well above the typical bandwidth setting and represents a direct cause of “wear-and-tear”.

The Company agrees with DPU witness Robert A. Davis who states: “It is a reasonable assumption that additional variability has the potential to wear out certain distribution equipment at a faster rate than otherwise would occur.”[4] Mr. Volkmann disagrees with Mr. Davis and concludes that the Company has provided no evidence to support reduced equipment life, and then quotes Mr. Davis who indicates there is no evidence there are system issues occurring at current customer generation

[3] *See* line 258 of Vote Solar witness Mr. Volkmann Rebuttal Testimony.
[4] *See* lines 186-188 of DPU witness Mr. Davis Direct Testimony.

penetration levels to bolster his argument.[5] Mr. Volkmann's attempt to use Mr. Davis' assessment regarding system issues is misleading as it equates Mr. Davis' assessment of "wear-and-tear" with system issues, which is a separate matter.

Q. Why is it difficult to quantify the "wear-and-tear" of voltage regulating devices?

A. It is difficult to quantify the number of operations occurring on regulating devices due to customer generation because it is only one of several variables that affect circuit voltage. Customer load and transmission voltage also play a role, therefore customer load variability and transmission operation variability can mask the increased operations directly caused by customer generation. What we can quantify is the number of devices that may be affected by increasing customer generation penetration levels, shown in the table below.

Figure 1. Installed Voltage Regulating Devices in Utah - as of June 2020

Device Type	**Quantity**
Load Tap Changer	261
Substation Regulator	491
Line Regulator	649
Line Switched Caps	99

Q. Does Rocky Mountain Power believe high penetrations of customer generation can significantly extend distribution transformer life as suggested by Mr. Volkmann[6]?

A. No. Mr. Volkmann's cites the 2013 technical white paper *Impact of High PV Penetration on Distribution Transformer Insulation Life*[7] but that paper is not directly applicable to the Company's distribution system. The distribution transformers

[5] *See* lines 130-132 and 157-160 of Vote Solar witness Mr. Volkmann Rebuttal Testimony.
[6] *See* lines 141-144 of Vote Solar witness Mr. Volkmann Rebuttal Testimony.
[7] H. Pezeshki, P. J. Wolfs and G. Ledwich, *Impact of High PV Penetration on Distribution Transformer Insulation Life*, IEEE Transactions on Power Delivery, vol. 29, no. 3, pp. 1212-1220, June 2014, available at https://core.ac.uk/download/pdf/19541682.pdf).

highlighted in this white paper refer to 3-phase transformers commonly used in Australia and the United Kingdom that serve 150 to 200 customers per transformer. For 3-phase transformers serving single phase customers, it is difficult to balance load among the three phases, and thus the likelihood of overloading a single phase on the transformer is high. As is noted in the white paper, transformers in the United States that serve single phase customers are typically single phase transformers and therefore do not have the same propensity for overloading. The white paper does demonstrate that high customer generation penetration can have a positive effect on overloaded transformers; however, given Rocky Mountain Power's standard of loading transformers to a maximum of 100 percent and the use of single phase transformers for which phase balancing is not a concern, the suggestion that customer generation can significantly extend transformer life in Rocky Mountain Power's system is greatly exaggerated.

Adoption of Smart Inverters

Q. Does Rocky Mountain Power believe smart inverters can resolve voltage issues created by customer generation?

A. Yes. Mr. Volkmann correctly cites the Electric Power Research Institute ("EPRI") smart inverter study commissioned by the Company through the Sustainable Transportation and Energy Plan ("EPRI Study"), which states: "By absorbing or injecting reactive power, smart inverters may be able to increase hosting capacity on certain feeders by reducing voltage variations resulting from increased generation."[8]

[8] *Advancing Smart Inverter Integration in Utah: Final Report*, EPRI, Palo Alto, CA: 2019, 3002015334, pg. 1-1, https://pscdocs.utah.gov/electric/19docs/1903517/307937RMPAttach8-4-30-19.pdf.

Q. Does Rocky Mountain Power have any reservations with utilizing smart inverters to mitigate voltage issues on the system?

A. Yes. The location of smart inverters can significantly affect whether or not they are effective, and deployment would involve considerable analysis and upfront costs. The EPRI Study identifies additional complexity relating to the adoption of smart inverters to regulate voltage. While reactive compensation proved effective in some of the circuits studied by EPRI, increasing reactive absorption on other feeders studied demonstrated constraining factors changing from overvoltage to thermal overload issues.[9] In addition, each circuit studied in volt-var mode demonstrated varying outcomes based on "worst," "good" or "best" volt-var settings. These outcomes included increased circuit losses and had a "significantly negative impact on power factor"[10] for poorly chosen settings. The Company gathers from the study that a more in-depth analysis of individual feeders will be needed in order to deploy "best" voltage regulating settings. Accordingly, while smart inverter regulation may regulate voltage on individual feeders, such regulation would also create costs, such as analysis, initial settings installations and possible ongoing or seasonal settings changes as well as the communications cost to deploy them. Mr. Volkmann's recommendation over-simplifies the theoretical benefits of smart inverters while ignoring their cost of management and administration.

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[9] *Advancing Smart Inverter Integration in Utah: Final Report*, EPRI, pg. 2-5.
[10] *Advancing Smart Inverter Integration in Utah: Final Report*, EPRI, pg. 3-7.

Q. Does Rocky Mountain Power agree with Mr. Volkmann's recommendation to change the Company's Policy 138 to require volt-var mode with reactive power priority and the IEEE Standard Category B default settings for inverter-based customer generation[11]?

A. No. The Company agrees with Volkmann that Policy 138 should be updated to reflect changes in IEEE 1547, but disagrees with the nature of the changes recommended. Given the EPRI Study, the Company would need to conduct a thorough investigation for each individual feeder to ensure thermal limits are not exceeded and confirm the "best" settings for each feeder are deployed. Rather than updating Company policy to require IEEE Standard Category B default settings, the Company is currently considering updating Policy 138, as recommended by EPRI, to allow the Company to revisit implementation of smart inverters in the future. [12]

Conclusion

Q. Please summarize your surrebuttal testimony.

A. Varying voltages due to customer generation will cause an increase in voltage regulating device operations that will wear out equipment more rapidly than would otherwise occur, thereby increasing Company costs. Smart inverters can mitigate voltage issues caused by customer generation, but inverter setting deployment is more complex than applying a blanket default setting which would drive further costs for the Company in management and administration.

Q. Does this conclude your surrebuttal testimony?

A. Yes.

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[11] *See* lines 362-368 of Vote Solar witness Mr. Volkmann Rebuttal Testimony.

[12] *Advancing Smart Inverter Integration in Utah: Final Report*, EPRI, pg. 4-1.

Rocky Mountain Power
Docket No. 17-035-61
Witness: Robert M. Meredith

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

Surrebuttal Testimony of Robert M. Meredith

September 2020

Q. Are you the same Robert M. Meredith that presented direct and rebuttal testimony in this proceeding?

A. Yes I am.

Purpose of Surrebuttal Testimony

Q. What is the purpose of your surrebuttal testimony?

A. I respond to the testimonies of Utah Clean Energy ("UCE") witness Ms. Kate Bowman, Vote Solar witnesses Mr. Sachu Constantine, Dr. Carolyn Berry and Mr. Curt Volkmann, and Vivint Solar witness Dr. Christopher Worley and support the Company's proposed program design for Schedule 137 – Net Billing Service.

Response to UCE witness Ms. Bowman

Q. In her rebuttal testimony, Ms. Bowman continues to argue that the successor customer generation program should have netting over longer interval periods.[1] Are any of her arguments new relative to her direct testimony?

A. No.

Q. Why should the Commission approve the Company's recommended approach with no netting?

A. As previously discussed in testimony, a no-netting approach more accurately reflects the characteristics of the service provided by the Company to its customers. No netting is also simpler for customers to understand and will integrate with other energy-related technologies that may be incorporated in the future, such as batteries. No netting is also less administratively burdensome for the Company.

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[1] *See* lines 67-188 and lines 978-1011 of UCE witness Ms. Bowman Rebuttal Testimony.

Response to Vote Solar witnesses Mr. Constantine, Dr. Berry, and Mr. Volkmann

Q. Mr. Constantine and Dr. Berry both argue that instantaneous netting is not "understandable and actionable for customers" because it is impractical for families to respond to solar output within the hour.[2] How do you respond?

A. As I demonstrated in my direct testimony, the difference in export values rendered between real time and 15 minute netting is generally small and would likely not drive a significant difference in the financial benefits of customer generation.[3] Further, the Company believes that the price signal that would be sent to Net Billing participants is actionable and clear. A customer will save more by shifting energy use to times when their system is generating peak amounts (i.e. when the sun is shining), and use less energy during times of lower production. The ability to do this is not dictated by the method of netting used. Additionally, as smart technology is implemented in households with generation systems, much of the task of responding to excess generation can be automated.

Q. Dr. Berry claims that instantaneous netting will make it difficult for solar installers to estimate the potential savings for prospective rooftop solar.[4] Do you think this would pose an insurmountable challenge for solar installers selling their products?

A. Not at all. Under Schedule 136, which utilizes a 15 minute netting process, 11,873 customer generation systems have been interconnected to date.[5] The Company

[2] See lines 413-435 of Vote Solar witness Mr. Constantine's Rebuttal Testimony and lines 513-527 of Vote Solar witness Dr. Berry's Rebuttal Testimony.
[3] See Exhibit RMP___(RMM-2) provided with Rocky Mountain Power witness Mr. Robert M. Meredith's Direct Testimony.
[4] See lines 560-567 of Vote Solar witness Dr. Berry's Rebuttal Testimony.
[5] Schedule 136 customer count is as of July 31, 2020.

maintains the position that instantaneous netting will not yield results that are significantly different from 15 minute netting, and it therefore does not believe its proposed program design will provide a greater challenge in estimating savings for prospective systems than under Schedule 136. It should also be noted that estimates could be made to forecast the proportion of production that would be exported based on the level of energy to be offset or the size of the generation system relative to monthly energy consumption. Vote Solar gathered a very significant volume of customer usage and production data, and the Company believes that it is capable of performing such an analysis. This type of information could also be used to develop a market for added battery storage as a method for shifting exported energy to meet onsite usage. Solar installers have shown prior innovation in how they market and sell rooftop solar systems to potential customers and should be able to continue that process in developing sales techniques around instantaneous netting.

Q. When a customer makes an investment to lower their energy bills, is there ever perfect certainty on how such an investment will perform?

A. No. With any sort of energy-saving investment made there is not a perfect understanding of the savings created. For example, a customer could install a heat pump water heater in an effort to reduce energy costs. However, to perfectly estimate those savings the customer would have to know the temperature of the area in which the water heater is installed, exactly how many showers they take and for how long, how many loads of dishes will be washed, how often guests will come and visit, the weather, and likely many other factors that will influence the benefits of a more efficient water heater. Because there are many factors, some of which are uncontrollable, perfect certainty is unlikely for any customer-sited energy-related investment. In a similar way, to expect that the financial benefits of a rooftop solar system should be known with perfect precision is unreasonable.

Q. Dr. Berry concludes that the Company has failed to support its position "that real-time netting is less administratively burdensome than other programs" because, she asserts, that the Company's claim that the "likelihood of requiring manual intervention with relying on registers instead of profile netting is much less" is untested since real-time netting for CG customers has never been used.[6] Is this true?

A. No. The Net Metering program on Schedule 135 uses the registers on the meters to measure all energy exported and all energy delivered and does not rely upon any particular interval to bill customers. For a residential customer on Schedule 1 who participates in Net Metering – Schedule 135, one data point is measured for exported energy in each monthly billing period. In contrast, the Schedule 136 Transition Program for Customer Generators which uses 15 minute interval netting requires on average 2,920[7] data points for exported energy. In the Company's experience, Schedule 136 has required more manual intervention and administrative burden than Schedule 135, because of the volume of data.

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[6] See lines 574-584 of Vote Solar witness Dr. Berry's Rebuttal Testimony.
[7] 365 days in a year divided by 12 monthly billing periods multiplied by 24 hours in a day and multiplied by four intervals in an hour yields 2,920 intervals.

Q. Dr. Berry dismisses the Company's analysis comparing the level of energy exported under 15 minute netting to meter register data where no netting occurs, because the difference in exported energy and delivered energy under 15 minute netting compared to no netting was not exactly the same amount in many of the observations.[8] Please comment.

A. The source for exported energy under 15 minute netting is the billing units used for the actual export credits included in the customer generator's bill. This information is calculated from 15 minute profile data. The source for the exported energy with no netting is the register reads from the meters. As discussed in my direct testimony, a comparison of these data show that no netting and 15 minute netting produce very similar overall values for exported energy.[9] While it is true that the observations do not always match as Dr. Berry points out, there is a good reason for this, and the lack of matching does not undermine the ultimate conclusion. As explained in the Company's response to Vote Solar Data Request 13.2-6, provided as Exhibit RMP__(RMM-1SR), the actual time periods over which exports are netted by 15 minute intervals for billing and the timing of the registers recorded on the meter are not always the same. For example, a meter register may have been read for the period between 10:00AM October 4th through 11:00AM November 1st for usage and exports over that timeframe, while the profile data where 15 minute netting occurs for the bill is 12:00AM October 4th through 12:00AM November 1st. It is also important to note that in most observations, these "anomalous" differences that Dr. Berry references between delivered and exported energy under 15 minute and no netting are very small.

[8] *See* lines 585-623 of Vote Solar witness Dr. Berry Rebuttal Testimony

[9] *See* lines 144-152 of Rocky Mountain Power witness Mr. Meredith direct testimony.

For about 96 percent of observations, the difference between exported and delivered energy under not netting versus 15 minute netting is less than 10 kilowatt-hours ("kWh"). Dr. Berry does not provide compelling evidence that my estimates of the difference in exported energy between 15 minute netting and no netting are inaccurate or unreasonable.

Q. Dr. Berry discusses how the proposed application fee is higher than for Schedule 136 and for customer generation application fees in PacifiCorp's other states.[10] Why is the application fee higher than what the Company had calculated for Schedule 136?

A. The Company used the same logic to calculate the proposed application fee for Schedule 137 as what was used for Schedule 136. The increase in the fee is the result of the new test period that was used. The new test period more accurately reflects the ongoing costs of processing applications. The previous test period was calculated during a high application volume period. The volume of applications caused the Company to employ a number of temporary contractors and require salaried employees to work for significant unpaid overtime hours to meet the demand. These practices, while lower cost over the short term, were not sustainable over the long term and resulted in a high level of employee turnover.

Q. Is the Company's proposed application fee for Schedule 137 excessive or unreasonable?

A. No. As discussed, the methodology used to develop the application fee is the same as was used for Schedule 136, but with updated data.

[10] See lines 807-830 of Vote Solar witness Dr. Berry's Rebuttal Testimony.

Q. With respect to administrative costs included in the application fee calculation, Dr. Berry claims that "(n)o cost support is provided for administrative costs, nor is any explanation provided as to how those costs are different from the administrative costs for all other customers."[11] Please comment.

A. The "Administration" costs shown in my Exhibit RMP___(RMM-3) are the per-application processing costs of the customer generation department. This department deals solely with processing applications for and supporting customers that have on-site generation. Other customer groups do not benefit from the work of this group and it is reasonable that these costs be collected through the application fee.

Q. Dr. Berry also claims that "(t)he engineering review costs provided in the analysis are average costs per application that do not account for the very different reviews necessary for Level 1, Level 2, and Level 3 applications."[12] What does the estimated engineering review cost reflect?

A. The engineering cost reflects a standard, simple Level 1 interconnection. It does not reflect the higher costs of more complicated interconnections. The vast majority of interconnection applications for Schedule 136 were level 1 (11,796 or about 99 percent). More complex level 2 and 3 applications for Schedule 136 were relatively less frequent (77 total or less than one percent).[13]

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[11] *See* lines 846-848 of Vote Solar witness Dr. Berry's Rebuttal Testimony.
[12] *See* lines 848-850 of Vote Solar witness Dr. Berry's Rebuttal Testimony.
[13] *See* the Company's response to Data Request UCE 6.1.

Q. Please comment on Dr. Berry's statement that PacifiCorp "cannot confirm that the costs for CG meter exchange work orders are any different from the costs for non-CG meter exchange work orders."[14]

A. When a customer adds on-site generation, its meter must measure bi-directional energy flows, often necessitating a meter exchange. The costs associated with installing this new meter are incurred by the customer adding the generation system and are fundamentally different than metering costs that are incurred as part of the Company's normal business operations such as replacement of broken meters or system wide upgrades. Since customer generators create the need for incremental metering costs, it is reasonable that they bear the cost.

Q. Dr. Berry discusses the differences between application fees for the varying fee levels included on Schedule 136 and concludes that increased fee is related to inclusion of the more complex interconnection requests.[15] Is her assessment correct?

A. No. The higher fees are a result of more recent data, as discussed earlier. The engineering review is not driving higher costs.

Q. Dr. Berry argues that preventing unnecessary applications is not a valid rationale for charging an application fee.[16] What has been the Company's experience with unnecessary applications?

A. In the final months of Schedule 135, the Company received a flurry of customer generator applications. While such a rush of applications was expected given the desire

[14] *See* lines 851-855 of Vote Solar witness Dr. Berry's Rebuttal Testimony.
[15] *See* lines 862-881 of Vote Solar witness Dr. Berry's Rebuttal Testimony.
[16] *See* lines 882-898 of Vote Solar witness Dr. Berry's Rebuttal Testimony.

to be grandfathered into Schedule 135, the Company found that some of these applications came from installers on behalf of customers who had never expressed interest in installing solar systems. Some installers submitted applications for whole neighborhoods they hoped to canvass, so that they could offer grandfathered status before having met with these customers. Along with recovering the direct costs to the Company of customer generation interconnections, an application fee is an effective tool to deter this type of behavior and to limit frivolous applications that increase the costs borne by customers with a real interest in customer generation.

Q. Dr. Berry recommends that the Company should utilize technology to lower its costs for processing customer generation applications and proposes that the application fees be lowered to incentivize the Company to get more efficient.[17] Has the Company considered or implemented any application processing systems?

A. Yes. The Company implemented PowerClerk as a method to improve the experience for prospective customer generators seeking interconnection. This technology has helped reduce time spent administering the customer generation program. However, these efficiencies are in part offset by software licensing fees. In the Company's experience, this technology has primarily improved customer service by allowing applicants to track where they are in the process and more easily submit fees. A significant amount of manual work is still required for the Company to process customer generation applications.

[17] *See* lines 899-914 of Vote Solar witness Dr. Berry's Rebuttal Testimony.

Q. Mr. Volkmann recommends lowering the Company's proposed $160 metering fee to $0.[18] What reasons does he give for not assessing a metering fee?

A. Mr. Volkmann asserts that the metering fee is arbitrary and inconsistent with current practices of the Company, because the Company does not currently charge non-customer generator customers for meter replacements and or upgrades.

Q. Do you agree with Mr. Volkmann that a $0 metering fee is appropriate?

A. No. As described earlier, the customer is electing to participate in a customer generation program which creates new costs unrelated to basic services. It is appropriate that these customers pay the incremental costs of participating in a voluntary program.

Q. Dr. Berry criticizes the Company's proposed time of use periods for the export credit, because the relative difference in on- to off-peak prices is less than 2:1 which is commonly regarded as a necessary level to induce behavioral change.[19] Please comment.

A. The purpose of the export credit design used by the Company is to reflect an accurate value of exported energy. While the export credit was not designed explicitly to induce a particular behavioral change, the proposed Net Billing program will send robust price signals to participants. There are two primary price signals at play in Net Billing. The first is to shift energy use to times when energy is being produced, the second is to shift exports away from the off-peak period. Both objectives can be accomplished by moving energy usage to the off-peak export time period. Dr. Berry is correct in her assessment that the 2:1 ratio of on- to off-peak credit is unlikely to alone drive behavioral change. However, it is the Company's belief that the ratio of retail rates to

[18] *See* lines 439-442 of Vote Solar witness Mr. Volkmann's Rebuttal Testimony.
[19] *See* lines 192-197 of Vote Solar witness Dr. Berry's Rebuttal Testimony.

export credit, which is as high as roughly 8:1,[20] will drive customers to align their usage with the times of high solar production. This can be accomplished through mindful energy usage, smart home technologies, battery installation, and other individually driven methods.

Q. Dr. Berry points out that the time of use periods for the export credit are inconsistent with the time of use periods for residential time of use options Schedule 2 and 2E.[21] Please comment.

A. The export credit time of use periods are based on the values of exports not on time of use programs whose on-/off-peak periods were set years in the past. The time of use periods for Schedule 2 were developed many years ago and do not reflect current conditions. The time of use periods employed for Schedule 2 are also inconsequential since there are very few customers (363) on it. For Schedule 2E, the pilot is experimental, only available for new participants through the end of this year, and customers on it are not allowed to participate in customer generation programs. The time of use periods do not need to be consistent between these schedules as they will likely have very little customer crossover, and so different time of use periods will not create confusion.

[20] The presently effective third tier summer residential rate of 14.4508 cents per kWh is about eight times greater than the 1.7080 cents per kWh off-peak summer export credit proposed by the Company in its Phase 2 Direct Testimony.
[21] *See* lines 201-223 of Vote Solar witness Dr. Berry's Rebuttal Testimony.

Response to Vivint Solar witness Dr. Christopher Worley

Q. Dr. Worley seems to suggest that instantaneous netting might compromise the benefits from smart inverters.[22] Please respond.

A. It is unclear why or how instantaneous netting would affect the benefits of smart inverters. Dr. Worley suggests that if smart inverters were required in Utah, there would be an increase in the benefits provided by customer generation. He then questions whether the Company contemplated these benefits when it proposed instantaneous netting. Dr. Worley presents no evidence or rationale why potential smart inverter requirements and the Company's proposed program design would conflict nor does he explain how this issue would be better addressed under hourly netting as he recommends.

Q. Dr. Worley recommends creating a tiered application cost to more accurately assign costs based on the complexity of application review necessary.[23] Does the Company believe this to be necessary?

A. No. As explained earlier, the vast majority of applications were level 1 and the Company's cost estimates are therefore reflective of that effort.

Q. Do you agree with Dr. Worley that the $160 metering fee is discriminatory[24] due to the Company's plans to install AMI meters in the near future?

A. No. As the Company makes metering updates across the entire residential class those costs are borne by the class through base retail rates as Dr. Worley describes. However, when a customer connects a generation system to the grid, they require measurement

[22] *See* lines 484-509 of Vivint Solar witness Dr. Worley's Rebuttal Testimony.
[23] *See* lines 515-535 of Vivint Solar witness Dr. Worley's Rebuttal Testimony.
[24] *See* lines 536-547 of Vivint Solar witness Dr. Worley's Rebuttal Testimony.

of the bidirectional energy flows, often necessitating a meter exchange, which is outside of the Company's regular operating activities. Requiring the customer that creates the cost to pay for it is not discriminatory and doing otherwise would be unfair for other customers.

Conclusion

Q. Please summarize your surrebuttal testimony.

A. The Company's proposed Net Billing program is fair for all customers, sends efficient price signals that encourage load to be matched with renewable energy output, and is relatively easy to understand. The application and metering fees the Company has proposed are also reasonable.

Q. What is your recommendation for the Commission?

A. The Company recommends that the Commission approve the Company's proposed Schedule 137 tariff.

Q. Does this conclude your surrebuttal testimony?

A. Yes.

Rocky Mountain Power
Exhibit RMP___(RMM-1SR)
Docket No. 17-035-61
Witness: Robert M. Meredith

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

Exhibit Accompanying Surrebuttal Testimony of Robert M. Meredith

RMP Response to Vote Solar Data Request 13.2-6

September 2020

17-035-61 / Rocky Mountain Power
June 11, 2020
Vote Solar Data Request 13.2

Vote Solar Data Request 13.2

Please refer to the RMP's Direct Testimonies filed on February 3, 2020, specifically work paper RMP Wrkprs RMM2 CompEnrgTotalExprts15MnNettedExprts 2-3-2020.

1. Please confirm that the column labelled "NMW" on the "Bill" tab contains amounts, in kWh, of delivered energy that has been netted with exports on a 15-minute basis and summed over each month in 2019 for each Schedule 136 customer.

2. Please confirm that the column labelled "NMR" on the "Bill" tab contains amounts, in kWh, of exported energy that has been netted with deliveries on a 15-minute basis and summed over each month in 2019 for each Schedule 136 customer.

3. Please confirm that the column labelled "KWH-U-T" on the "Bill" tab contains amounts, in kWh, of delivered energy that has not been netted with exports but is based on meter register data for each month in 2019 for each Schedule 136 customer.

4. Please confirm that the column labelled "KWH-DEDUCT-T" on the "Bill" tab contains amounts, in kWh, of exported energy that has not been netted with deliveries but is based on meter register data for each month in 2019 for each Schedule 136 customer.

5. Please confirm that if the quantity of deliveries (or exports) in an interval is netted, and then this amount is "un-netted" or separated into gross amounts of deliveries and exports, that the increase in the quantity of deliveries and the increase in the quantity of exports in this interval must be equal. For example, if in a given 15-minute interval, the about of net deliveries is 10 kWh, and then this amount is separated into gross deliveries and exports and it is found that the gross amount of deliveries is 15 kWh, then it must be the case that the gross amount of exports in this interval is 5 kWh.

6. A review of the data in the columns labelled NMV, NMR, KWH-U-T, and KWH-DEDCUT-T on the "Bill" tab shows that the relationship described in VS13-2.5 has been violated for 82.6% of the observations, and that in over 17% of these cases the discrepancy is greater than 4 kWh. Please confirm that discrepancies of this type and magnitude are found in the netting analysis contained in RMP Wrkprs RMM2 CompEnrgTotalExprts15MnNettedExprts 2-3-2020.

Response to Vote Solar Data Request 13.2

1. Confirmed. The column labelled "NMV" on the "Bill" tab represents the net delivered kilowatt-hour (kWh) by the Company to the customer derived from the interval meter reading based on the customer's invoice in 2019 for each Schedule 136 customer.

2. Confirmed. The column labelled "NMR" on the "Bill" tab represents the net exported kWh by the customer to the Company derived from the interval meter reading based on the customer's invoice in 2019 for each Schedule 136 customer.

3. Confirmed. The column labelled "KWH-U-T" on the "Bill" tab represents the delivered kWh by the Company to the customer from the meter register based on the customer's invoice in 2019 for each Schedule 136 customer.

4. Confirmed. The column labelled "KWH-DEDUCT-T" on the "Bill" tab represents the exported kWh by the customer to the Company from the meter register based on the customer's invoice in 2019 for each Schedule 136 customer.

5. Confirmed. For a particular interval period, this will be the case.

6. While the relationship described in Vote Solar data request 13.5 is accurate for an individual interval period, this will not be the case for all observations in the RMP Wrkprs RMM2 CompEnrgTotalExprts15MnNettedExprts 2-3-2020 workpaper, primarily because the time period over which usages are calculated using meter registers and the period of the profile that is netted on a 15 minute interval period may be slightly different. For example, meter registers may have been read for the period between 10:00AM October 4th through 11:00AM November 1st for usage and exports over that timeframe, while the profile data where 15 minute netting occurs for the bill is 12:00AM October 4th through 12:00AM November 1st.

CERTIFICATE OF SERVICE

I hereby certify that on September 15, 2020, a true and correct copy of Rocky Mountain Power's **SURREBUTTAL TESTIMONY** in Docket No. 17-035-61 was served by email on the following Parties:

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