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BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH

In the Matter of the Application of Rocky Mountain Power to Establish Export Credits for Customer Generated Electricity	**DOCKET NO. 17-035-61** **Vivint Solar Exhibit 1R** **Phase 2**

REBUTTAL TESTIMONY OF CHRISTOPHER WORLEY, PH.D.
FOR VIVINT SOLAR, INC.

July 15, 2020

/s/Christopher Worley

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I. INTRODUCTION AND PURPOSE OF TESTIMONY

Q. Please state your name, title and business address.

A. My name is Christopher Worley. My business address is 1800 W. Ashton Blvd, Lehi, Utah 84043. I am Director of Rate Design with Vivint Solar.

Q. Did you submit direct testimony in this proceeding?

A. Yes.

Q. What is the purpose of your rebuttal testimony?

A. The purpose of this testimony is to respond to the direct testimony of other parties in this case and provide additional recommendations for the Commission.

II. SUMMARY

Q. Can you provide a high-level overview of your position on the direct testimony filed in this case?

A. Yes. I agree with much of the testimony filed by Utah Clean Energy witness Kate Bowman, testimony filed by Ryan Evans on behalf of the Utah Solar Energy Association, and the six witnesses representing Vote Solar. Those witnesses have provided the Commission thoughtful policy context and empirical rigor to this discussion. In contrast, I disagree with much of the testimony filed by Rocky Mountain Power (RMP) and the Division of Public Utilities (DPU). I disagree with the methodology used in RMP's export credit rate estimate, and most glaringly, their valuation ignores long-run marginal costs that net metered solar defers or avoids. Lastly, the Office of Consumer Services (OCS) witness Cheryl Murray provides some important principles for the Commission that are worth discussing.

Q. How will you structure this rebuttal testimony?

A. I will first discuss key principles raised by parties and relate them to principles I recommended in my direct testimony. Then I will give context on the market for distributed solar, including why customers might choose to invest in behind-the-meter solar. Based on my reading of testimony, some parties seem to have fundamental misconceptions about solar customers and the solar market. Then I will discuss short-run and long-run utility costs and why the export credit rate should account for long-run utility costs when setting the export credit rate. Lastly, I will finish by addressing RMP's proposed meter and application fees.

Also, I have updated my recommended export credit rate based on Vote Solar's testimony, which included estimated values for avoided distribution capacity, reduced fossil fuel hedging, and carbon compliance. Vote Solar's testimony provides more support that the value of the export credit rate should be set to at least 9.2 cents per kWh as I recommended in my Direct Testimony (*see* Table 1). Based on the totality of modeling and evidence presented, I concur with Vote Solar's conclusion that the benefits of solar exceed its costs.[1] My updated

[1] Revised Affirmative Testimony of Sachu Constantine, lines 522 and 523.

recommendation is that the export credit rate should be set at the retail rate.

Table 1: Value of export credit factors

Factor	Value (cents/kWh)
Avoided energy (including system losses)	3.37
Avoided generation capacity	2.22
Avoided transmission capacity	1.90
Avoided distribution capacity[2]	0.52
Hedging value[3]	0.19
Carbon compliance cost[4]	2.80
Other factors (including resilience, environmental benefits, others)	not quantified
Export credit	**At least 11.00**

The testimony filed by parties is extensive, so I will not address every issue that every party raises. Instead, I will focus on key areas of disagreement between the parties, and provide additional context and arguments supporting Vivint Solar's position in this case. Not commenting on another party's position should not be construed as support of that position, and I reserve the right to return to those issues in my surrebuttal testimony as additional testimony is filed.

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[2] Revised Affirmative Testimony of Sachu Constantine, Table 1.
[3] Revised Affirmative Testimony of Sachu Constantine, Table 1.
[4] Revised Affirmative Testimony of Sachu Constantine, Table 1.

III. KEY PRINCIPLES

Q. What principles did you recommend the Commission use when adopting an export credit rate in this case?

A. In my direct testimony, I provided the following list of principles the Commission should consider when setting an export credit rate:[5]

1. *Solar customers should receive fair compensation for the value provided to the grid.*
2. *Solar policies should be certain and only change gradually.*
3. *Solar policies should be understandable for customers.*
4. *Solar policies should not treat retail customers like independent power producers.*

This list is grounded in traditional rate design principles and would not unfairly discriminate against customers that install on-site solar.

Q. How do export credit rate proposals of other parties meet these criteria?

A. Vote Solar is recommending reopening the net metering program, or in the alternative, set the export credit rate at 22.22 ¢/kWh. While I am not recommending those approaches, Vote Solar's analysis shows that the benefits of solar outweigh the cost, and as such, setting the export credit rate at the retail rate would meet all four criteria. Retail rate compensation would provide fair compensation for net metered solar customers and would make RMP's solar policy clear and understandable. By locking in compensation at the retail rate, RMP's net metering program would acknowledge and treat retail customers appropriately and ensure certainty in the terms of the customer's solar investment.

Q. How does RMP's export credit rate proposal fit with these principles?

[5] Direct Testimony of Christopher Worley, lines 109-126.

A. The proposal presented by RMP fails to meet any of the principles I laid out in my direct testimony. In short, RMP would unfairly discriminate against customers that have installed solar with a rate schedule, creating confusing solar policies that could change from year to year. RMP's proposed export credit rate does not provide fair compensation for the value that distributed solar provides to the grid. If approved, RMP's proposal would shut down the market for distributed solar within Utah.

Q. Do other parties recommend principles in their direct testimony?

A. Yes, Kate Bowman (UCE) and Cheryl Murray (OCS) both recommend principles for the Commission to consider.

Q. Do you agree with the principles raised by Ms. Bowman?

A. Yes. Ms. Bowman raises these principles:

- "The Export Credit Rate should be just and reasonable and in the best interest of the well-being of Utah
- The Export Credit Rate should be simple and comprehensible to customers
- If the new Export Credit Rate is lower than the current Transition Program credit, I recommend that gradualism be employed
- Customers who install solar should be locked into the Export Credit Rate that is current at the time of their interconnection application for 20 years"[6]

These criteria align with the principles I laid out in my direct testimony. I agree with Ms. Bowman's recommendations.

Q. What are the principles raised by OCS witness Murray?

A. Ms. Murray states that the OCS will use two principles to evaluate export credit rate proposals and will support proposals that are "true cost-based rates" and provide "bill simplicity and transparency".[7]

Q. Do you agree with Ms. Murray's principles?

[6] Direct Testimony of Kate Bowman, lines 224-230.
[7] Phase II Direct Testimony of Cheryl Murray, lines 60-65.

A. In broad strokes, I agree with those criteria and think they align with the principles I recommend.

Q. Do you have any concerns with Ms. Murray's application of the OCS principles?

A. Yes. I am hesitant to fully support Ms. Murray based on my reading of her discussion on which costs and benefits should be considered. Ms. Murray makes two references to Commission Orders in Docket No. 14-035-114. First, she quotes the July 1, 2015 Order: "Costs or benefits that do not directly affect the utility's cost of service will not be included in the final framework to be established in this phase of the docket." And then she quotes the order dated November 1, 2015: "To the extent any party believes a cost impact of net metering should be included in one of the studies or used to supplement the result of a study, the party bears the burden to demonstrate the existence of the impact and that it will be (or has been) realized in the test period." Lastly, she states: "OCS will expect that any party proposing export credit rates in this docket will adhere to the PSC's requirements."

While this could be an issue of interpretation, I fear OCS is raising a strict bar on the costs and benefits the Commission should even consider. The Commission has provided a guideline of the type of evidence they need to weigh evidence and make a decision. Parties are always afforded the opportunity to present a totality of evidence to support their case. For example, if a party wanted to estimate the value of net metered systems at avoiding (or deferring) investment in transmission capacity. The burden of proof in this case should not be that a specific transmission project was avoided (or deferred) during the test period. That is not a reasonable way to evaluate long-run marginal costs, like transmission investments that take many years to develop.

IV. CONTEXT ON THE COMPETITIVE SOLAR MARKET

Q. Can you please elaborate on the history of solar adoption outlined by RMP witness Joelle Steward?

A. In her direct testimony, Ms. Steward provides a short history of Utah's solar market and how this case came about. She states: "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."[8]

Q. Do you agree or disagree with Ms. Steward's statement?

A. I agree with the two facts that Ms. Steward references: the cost of solar modules has decreased over that timeframe, and that the federal solar Investment Tax Credit ("ITC") was established in 2006.[9] While I could not find data on module price over the timeframe she discusses, one NREL study reported that the all-in installed cost of residential solar declined from $7.34/Wdc in 2010 to $2.70/Wdc in 2018.[10] The federal Solar ITC provided a 30% tax credit on the amount of solar investment for projects installed between 2006 and 2019. However, this year the ITC declined to 26%, next year it will decline to 22%, and the residential credit will be eliminated after 2021.[11] While her facts are generally correct, her conclusion is that these two factors alone led to the rapid growth in solar adoption. That conclusion is reductionist and fails to give context on the solar market and energy markets more broadly. For example, all energy sources receive some sort of government incentive, including favorable tax mechanisms, and many factors have led to the decline in the installed cost of solar.

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[8] Direct Testimony of Joelle R. Steward, lines 85-87.
[9] Solar Investment Tax Credit (ITC) https://www.seia.org/initiatives/solar-investment-tax-credit-itc
[10] Fu, Ran, David Feldman, and Robert Margolis. 2018. U.S. Solar Photovoltaic System Cost Benchmark: Q1 2018. Golden, CO: National Renewable Energy Laboratory. NREL/TP-6A20-72399. https://www.nrel.gov/docs/fy19osti/72399.pdf. *See* Figure ES-1.
[11] Solar Investment Tax Credit (ITC) https://www.seia.org/initiatives/solar-investment-tax-credit-itc

Q. Do other energy sources receive tax credits, favorable tax status, and direct subsidies?

A. Yes. All energy sources receive government incentives through various mechanisms. For better or worse, the United States tax code includes credits and other mechanisms to give favorable status or "subsidies" to every source of energy. These incentives include the use of master limited partnerships for petroleum companies, the federal Production Tax Credit used by wind power producers, and a number of direct subsidies for the nuclear power industry.[12] Also, the rental rate for energy development on public lands are as low as $1.50/acre[13], and nearly all Bureau of Land Management (BLM) coal leases between 1990 and 2013 only had one bidder, so they were not set through competitive auctions.[14] If RMP purchases coal from a coal mine with a BLM lease, then the price RMP pays for that coal is likely to be lower than a competitive market price. It is disingenuous to highlight solar energy incentives without recognizing that every energy source receives incentives.

Q. Do you take issue with Ms. Steward's statement on the cost of solar modules?

A. Yes. As with her statement on solar tax incentives, highlighting the decline in solar module costs undercuts the hard work, the entrepreneurship, and the innovation seen in the solar industry over the last 15+ years.

It is true that solar module costs have declined over the past decade, but other costs have fallen as well. NREL tracks the installed cost of solar for residential, commercial, and utility-

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[12] U.S. Energy Information Administration - EIA - Independent Statistics and Analysis. (n.d.). Retrieved July 15, 2020, from https://www.eia.gov/todayinenergy/detail.php?id=41534

[13] Gentile, N. (n.d.). Federal Oil and Gas Royalty and Revenue Reform. Retrieved July 15, 2020, from https://www.americanprogress.org/issues/green/reports/2015/06/19/115580/federal-oil-and-gas-royalty-and-revenue-reform/

[14] Hein, Jayni. 2018. *Federal Lands and Fossil Fuels: Maximizing Social Welfare in Federal Energy Leasing* Harvard Environmental Law Review https://ssrn.com/abstract=2919094

scale installations, examining the cost components and identifying trends. In their most recent *U.S. Solar Photovoltaic System Cost Benchmark* (dated Q1 2018), they note that between 2010 and 2018, hardware costs accounted for 57% of the overall cost reduction, including modules, inverters, and hardware "balance of system". Other cost reductions are attributed to labor costs (19%) and "soft costs" (24%), which include permitting, inspection, interconnection, overhead, and other costs.[15]

These cost reductions do not happen magically. Cost reductions happen because of hard work, investment, and entrepreneurship. Cost reductions happen when module manufacturers invest in their facilities, optimize their production, and earn economies of scale as their facilities increase in size. Cost reductions happen when installers increase labor productivity through training and standardization, to the point where they may only need three crew members to install a system when they previously needed six employees. Cost reductions happen when companies optimize their supply chains and reduce the carrying cost of equipment. Cost reductions occur through financial innovation, like when SolarCity completed the first securitization of solar assets in 2013.[16] Solar installers continue to optimize their processes, invest in their companies, and respond to new market conditions because cost savings are not guaranteed. In the NREL report, there was a year-over-year cost decrease due to factors like higher labor productivity, lower supply chain costs, and higher module efficiencies. However,

[15] Fu, Ran, David Feldman, and Robert Margolis. 2018. *U.S. Solar Photovoltaic System Cost Benchmark: Q1 2018.* Golden, CO: National Renewable Energy Laboratory. NREL/TP-6A20-72399. https://www.nrel.gov/docs/fy19osti/72399.pdf. *See* page 21.

[16] O'Sullivan, Francis M. and Charles H. Warren. 2016. *Solar Securitization: An Innovation in Renewable Energy Finance.* Cambridge, MA: MIT Sloan School of Management. https://energy.mit.edu/wp-content/uploads/2016/07/MITEI-WP-2016-05.pdf

other factors increased in costs, specifically higher labor wages and higher module prices.[17] The decline in module price that Ms. Steward touts is not guaranteed.

Many business decisions have driven down the cost of installing solar, and with the number of installers that operate locally, regionally, and nationally, those cost savings are largely passed on to consumers. In my experience, customers invest in solar based primarily on cost savings, and they will choose the solar installer that will save them the most money. Solar installers are continually looking for ways to trim costs, because doing so will allow them to sell to customers at a lower cost. If our customers are not satisfied, then we may lose their business. And given the word of mouth nature of solar, we may lose the business of their family, friends, and neighbors.

Q. Why should the Commission care about Ms. Steward's mischaracterization of the solar market?

A. RMP would like to frame the discussion in this case as solar customers not paying their fair share of system costs. Based on estimates provided by Vivint Solar and Vote Solar, that is untrue. By focusing on tax incentives and low-cost solar modules, RMP dismisses the entrepreneurship and value creation by solar companies. While it is not surprising that a regulated monopoly with a captive customer base would not understand how firms in competitive markets operate, the Commission should have a better picture of the innovation and entrepreneurship in the solar industry, and the impact this case is likely to have on Utah's solar market.

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[17] Fu, Ran, David Feldman, and Robert Margolis. 2018. *U.S. Solar Photovoltaic System Cost Benchmark: Q1 2018*. Golden, CO: National Renewable Energy Laboratory. NREL/TP-6A20-72399. https://www.nrel.gov/docs/fy19osti/72399.pdf. *See* table ES-2.

Solar installers are choosing to organize capital efficiently and create value for consumers, and the success of solar installers is built upon the value we create for customers. In contrast, instead of creating value for customers and the economy, RMP is trying to use their monopoly status to interfere with a competitive market and is attempting to kill Utah's solar industry. Economist George Stigler referred to this approach as "regulatory capture".[18] More specifically, RMP is exhibiting rent-seeking behavior by changing rules to protect their interests rather than creating value for the economy. Solar installers invest in their business to grow the economy and help customers invest in their homes. In contrast, RMP is investing in a market barrier for solar. RMP's initial proposal for the export credit rate will shut down the market for behind-the-meter solar in Utah. Vivint Solar is a national installer with customers in 22 states and will survive by focusing on markets in other states, but RMP's proposed export credit rate will destroy the economic value that local installers have built. It will eliminate the ability of customers to invest in solar to help control their energy bills. It would be simply impossible for a solar market to exist under the export credit proposed by RMP, regardless of any future cost reductions to solar equipment. RMP's proposal would be the most punitive rate schedule to solar customers found anywhere in the nation and imposed at much lower solar penetration levels than other states. Utah would truly be an outlier in solar policy.

V. SUMMARY OF EXPORT CREDIT PROPOSALS

Q. Can you summarize and provide any high-level thoughts about export credit rate proposals made by other parties?

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[18] Stigler, George J. 1971. The Theory of Economic Regulation. The Bell Journal of Economics and Management Science, pages 3-21.

A. Yes. Vote Solar casts a wide net on the benefits solar can provide to the grid and to the community. The utility-based costs include components of short-run marginal costs (e.g., avoided energy, avoided line losses, and reduced fuel price hedging) and long-run marginal costs (e.g., avoided generation, transmission, and distribution capacity). Community benefits include elements like the health benefit from reduced air pollution and local economic benefits. Vote Solar estimates the utility benefits total to 10.57 ¢/kWh 2021USD, and community benefits sum to 12.03 ¢/kWh 2020USD.[19] I generally agree with Vote Solar's approach. While the community benefits may not be traditionally included in utility ratemaking, the Commission should have the fullest context when deciding this case.

In contrast, RMP undervalues the benefits that behind-the-meter solar provides to the grid. Their estimate includes only avoided energy, avoided line losses, and an integration factor. Also, RMP complicates the export rate further with seasonal (i.e., summer and winter) and time-based (i.e., peak and off-peak) export credit rates. RMP's average annual export rate is 1.526 ¢/kWh, much lower than estimates provided by Vivint Solar and Vote Solar.[20] I disagree with RMP's approach in this case. By only including some components of short-run marginal costs, they drastically undervalue the benefits of solar. And while I am not opposed to seasonal and time-based rates, I find RMP's proposal to be overly complicated and seemingly designed to confuse customers. Some utilities around the country are switching to time-based rates to better align customer incentives with utility system costs. However, making that switch requires an immense public education campaign to teach customers that reducing their usage during peak times will avoid higher bills. Customers on RMP's proposed rate would need to be aware of four

[19] Revised Affirmative Testimony of Carolyn A. Berry, Ph.D, Table 1
[20] Direct Testimony of Joelle R. Steward, line 187.

pieces of information (i.e., the time, the month, their current usage, and solar system production) to similarly respond to a seasonal, time-of-day export credit rate.

Q. Why do estimates by other parties differ from your own estimates?

A. There are multiple methodologies to estimate these values. In 2014, the National Renewable Energy Laboratory ("NREL") published a study outlining methodologies for estimating the value of solar components. For example, the value of avoided energy could be calculated using five different approaches: the value from the marginal unit, a blend of marginal generators, market pricing, simple dispatch modeling, or using production simulation.[21] While there is some variation between the Vote Solar and Vivint Solar estimates, they are generally close in value. I have reviewed Vote Solar's methodology and calculations and believe their approach to be reasonable. In fact, I have updated my export credit rate to include the Vote Solar estimates for avoided distribution capacity, fuel price hedge, and carbon compliance costs.

Q. Why do you categorize costs in terms of short-run and long-run marginal costs?

A. I categorize the utility-specific costs in terms of short-run and long-run marginal costs to highlight what I see as a key area of disagreement. RMP and DPU seem to argue that because solar is an intermittent resource, then behind-the-meter solar has no ability to avoid long-run marginal costs. Vivint Solar and Vote Solar argue that while solar is an intermittent resource, the extent to which solar provides energy at the system peak should be quantified and the value should be included in the export credit rate.

Q. What is the difference between short-run and long-run marginal costs?

[21] Denholm, P. et al. 2014. *Methods for Analyzing the Benefits and Costs of Distributed Photovoltaic Generation to the U.S. Electric Utility System.* Golden, CO: National Renewable Energy Laboratory. NREL/TP-6A20-62447 https://www.nrel.gov/docs/fy14osti/62447.pdf *See* page viii.

A. In economic theory, a firm makes production decisions in the short run based on their existing capital stock. Firms will optimize their use of factors of production (like capital, labor, and fuel) to produce their product at the lowest cost. In the short run, RMP provides electric service to their customers by organizing their labor force to operate their existing stock of capital (e.g., generators, transmission and distribution lines) and use fuel (e.g., coal and natural gas) to produce electricity at the lowest cost. In the short run, RMP can make decisions on how much fuel and labor to use, and while they can decide which units of capital to dispatch, they cannot change their existing stock of capital. RMP can make long-run investment decisions that will change and expand their capital stock. RMP's long-run investment decisions happen through the Integrated Resource Plan process to acquire new generation resources, and through the regional transmission planning and the Commission's CPCN process to build new high voltage transmission lines.

Q. Why is this distinction between short- and long-run marginal costs important?

A. All parties seem to agree that behind-the-meter solar impacts how RMP operates their system on a day-to-day basis, thereby avoiding some short-run marginal costs. While there is disagreement on which factors to include, and how to calculate those factors, all parties acknowledge that customer-sited solar provides short-run benefits to the system. Where there seems to be more disagreement is in whether customer-sited solar impacts long-term capital investment decisions. I (and other parties) will argue that customer investment in behind-the-meter solar impacts both how RMP operates their system in the short run and how they invest in their system in the long run. As such, the export credit rate should compensate solar for the value of deferring and/or avoiding long-run investment in RMP's fleet of generators, and the transmission and distribution systems.

VI. SHORT-RUN MARGINAL COSTS

A. Avoided energy

Q. Can you please discuss methodologies used by parties to estimate the value of avoided energy?

A. Yes. My estimate of the value of avoided energy was calculated using average locational marginal price ("LMP") data from the CAISO Energy Imbalance Market ("EIM"). I averaged three years of 15-minute data at an LMP node in Salt Lake City to generate an average value for energy during reasonable daylight hours.[22] Vote Solar uses PacifiCorp's Official Forward Price Curve ("OFPC"), which is based on a WECC-wide market model. Vote Solar argues this is an appropriate estimate of the avoided energy cost because it is a forward-looking model based on market prices.[23] RMP uses PacifiCorp's Generation and Regulation Initiative Decision Tool ("GRID"), an operational model used to calculate avoided costs for qualifying facilities.[24]

Q. What is your opinion on these approaches and what is your recommendation?

A. I agree with Vote Solar's use of the OFPC because that model is tied to market prices. I disagree with RMP's use of the GRID model for two main reasons. Firstly, the GRID model is used to model utility-scale projects and does not model changes in net load from behind-the-meter solar. Secondly, utility operational models (like GRID) may use market prices as inputs, however the assumptions built into the model are opaque and likely "stack the deck" in favor of outcomes preferred by the utility. Using the GRID model clearly stacks the deck against behind-the-meter solar when market price proxies are available. I continue to recommend the Commission adopt my estimate of avoided energy (3.37 ¢/kWh).

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[22] Direct Testimony of Christopher Worley, lines 165-169.
[23] Revised Affirmative Testimony of Michael Milligan, Ph.D., lines 486 to 495
[24] Direct Testimony of Daniel J. MacNeil, lines 60-68.

B. Avoided line losses

Q. Can you please discuss methodologies used by parties to estimate the value of avoided line losses?

A. Yes. My approach to avoided line losses is to use the gross EIM nodal prices in the avoided energy factor, which implicitly includes the value of avoided line losses.[25] RMP conducted a system line loss study in 2011 based on 2009 data.[26] The structure and assumptions embedded in that model are not transparent. The data they use is over ten years old, which is well before behind-the-meter solar had any significant penetration in RMP service territory. Given the age of the data alone, I question the efficacy and appropriateness of the results.

Q. What is your opinion on these approaches and what is your recommendation?

A. RMP's use of a proprietary model when a market price proxy is available stacks the deck in their favor. I recommend the Commission deny use of RMP's model to value avoided line losses, and instead use the embedded avoided line loss value in gross EIM nodal prices.

C. Integration cost

Q. What is the integration cost and how does RMP calculate it?

A. According to RMP witness Mr. MacNeil, RMP "uses flexible resources to accommodate fluctuations in the load and resource balance of its system attributable to load, wind, solar, and other non-variable energy resources that are not under the Company's control."[27] The integration cost represents the cost of holding reserves to maintain system balance. PacifiCorp conducted a Flexible Reserve Study as part of its 2019 IRP process. PacifiCorp uses the Planning and Risk (PaR) model production cost model to determine the reserve requirements for incremental wind

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[25] Direct Testimony of Christopher Worley, lines 155-160.
[26] Direct Testimony of Daniel J. MacNeil, lines 136-146
[27] Direct Testimony of Daniel J. MacNeil, lines 54-57.

and solar, which allows them to estimate the cost of holding additional flexible resources.[28] RMP estimates a solar integration cost of $0.15/MWh in 2021.[29]

Q. What concerns do you have with RMP's integration cost methodology?

A. Based on my reading of the Flexible Reserve Study, the PaR model does not differentiate between behind-the-meter solar resources and solar resources connected to the transmission system. While $0.15/MWh is debatably an appropriate integration cost for utility-scale solar, it is an inappropriate factor to assess solar resources that reduce load behind the meter and on the same distribution circuit. Utility-scale solar resources are connected to the transmission system. Solar production from those facilities are continually monitored, and if output changes due to weather or unplanned outage, then the utility must dispatch flexible resources to respond. In contrast, behind-the-meter solar offsets customer usage onsite, thereby reducing the net load visible to the utility. If weather conditions change and on-site solar production decreases, a customer's net load will increase, but from the utility's perspective, the change in net load is indistinguishable from increases in load due to electric vehicle charging, home cooling, laundry, or other end use consumption. In the case when behind-the-meter solar production exceeds load, energy is exported to the grid and is consumed by the nearest load source, which is very likely a neighboring home or business. One might imagine a case where a distribution circuit has many solar customers and during peak times, solar production might be greater than solar consumption and the flow of electrons reverses at the distribution feeder, which might require additional flexible resources to maintain system balance. But RMP has presented no information suggesting such events occur with frequency, or that oversupply of solar on the distribution system incurs a

[28] PacifiCorp, 2019 Integrated Resource Plan, Appendix F - Flexible Reserve Study. *See* pages 77 and 78.https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificorp/energy/integrated-resource-plan/2019_IRP_Volume_II_Appendices_A-L.pdf

[29] Direct Testimony of Daniel J. MacNeil, lines 165-166.

significant cost to manage. Also, it is unclear that the PaR model would be the correct tool to model distribution system-level oversupply events. RMP has not made a compelling case that balancing customers with behind-the-meter solar incurs an incremental cost above the cost to balance customers without solar.

Q. Does Vote Solar include integration cost in their export credit rate?

A. No. Based on their analysis, they found that RMP is at worst spending $64,000 per year to integrate customer-sited solar. Allocating that cost evenly to the 405,890 MWh of generation from behind-the-meter solar in 2019 would result in an integration cost of 0.016 ¢/kWh, which they argue is negligible.[30] I agree.

Q. What is your recommendation regarding integration costs?

A. I recommend denying inclusion of RMP's proposed integration cost factor.

D. Avoided fossil fuel hedging

Q. Do parties offer estimates of other short-run benefits that should be included in the export credit rate?

A. In my direct testimony, I recommended the Commission consider the cost of utility hedging programs for fossil fuels, though I did not include an estimate of the value that behind-the-meter solar provides. Vote Solar referenced a recent decision by the Oregon Public Utility Commission (PUC) finding that solar provides a tangible benefit by reducing hedge contract premiums. Based on a study by E3 Economics, the Oregon PUC adopted an avoided hedge value of 5% of avoided energy costs.[31]

Q. What are your recommendations regarding avoided fossil fuel hedging?

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[30] Revised Affirmative Testimony of Curt Volkmann, lines 318-320.

[31] See discussion and references in Revised Affirmative Testimony of Carolyn A. Berry, Ph.D, lines 549-569.

A. I agree with Vote Solar's recommendation to adopt the methodology approved by the Oregon PUC for PacifiCorp and include a value of 0.20 ¢/kWh in RMP's export credit rate.

VII. LONG-RUN MARGINAL COSTS

Q. Did parties estimate long-run marginal costs to include in the export credit rate?

A. Yes. Vote Solar estimated the value of avoided generation capacity, avoided transmission capacity, avoided distribution capacity costs, avoided carbon compliance. I have provided a comparison below in Table 2.

Table 2: Comparison of Vivint Solar and Vote Solar long-run marginal costs

	Vivint Solar	Vote Solar
	¢/kWh 2020USD	¢/kWh 2021USD (levelized)
Avoided generation capacity	2.22	1.48
Avoided transmission capacity	1.90	1.34
Avoided distribution capacity	not quantified	0.52
Avoided carbon compliance	not quantified	2.80

Q. What differences do you note in methodology and estimation of Vivint Solar and Vote Solar's approaches?

A. As noted above, there are multiple ways to calculate each of these factors. Both Vivint Solar and Vote Solar calculated avoided generation capacity using somewhat similar approaches, but used different data and assumptions, and therefore ended up with slightly different results. Avoided transmission capacity was calculated using different methodologies, but the estimates are fairly close, which suggests a robustness in results. While Vivint Solar did not estimate the value of avoided distribution capacity or the value of avoided carbon compliance.

Q. Can you please explain the differences in approaches to avoided generation capacity and provide any recommendations?

A. Yes. The main differences occur with the capacity factor parameter and the capacity cost of the avoided generating unit. Vote Solar witness Dr. Milligan provided an explanation of the "capacity factor method", wherein the 10% of top load hours are used as an approximation of the Effective Load Carrying Capacity ("ELCC") of a resource.[32] Using solar energy production in those hours, he calculated a capacity factor of 27.65%. In contrast, I use the capacity contribution of solar calculated by PacifiCorp's in its 2019 Integrated Resource Plan.[33] In terms of the capacity cost of the avoided generating unit, Dr. Milligan selected a generating unit from Pacifcorp's 2019 IRP, with a base capital cost of $316/kW.[34] I selected the average cost of a gas peaking plant ($825/kW) from the 2019 update to Lazard's Levelized Cost of Energy report. I agree with Dr. Milligan's approach because his capacity factor assumption and selection of a generating unit from PacifiCorp's IRP may more closely model the specific details of RMP's system than my approach. That said, I continue to recommend including an avoided generation capacity factor of 2.22 cents/kWh in the export credit rate.

Q. Can you please explain the differences in approaches to avoided transmission capacity and provide any recommendations?

A. Yes. I estimated the value of avoided transmission capacity using the National Economic Research Associates (NERA) Method, which has been used in marginal cost of service studies since the 1970s. The NERA approach regresses transmission investments against peak demand,

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[32] Revised Affirmative Testimony of Michael Milligan, Ph.D., lines 486 to 495

[33] PacifiCorp, 2019 Integrated Resource Plan, Appendix N - Capacity Contribution Study, https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificorp/energy/integrated-resource-plan/2019_IRP_Volume_II_Appendices_M-R.pdf See page 401.

[34] Revised Affirmative Testimony of Michael Milligan, Ph.D., lines 549-553.

with the slope of the regression line estimating the marginal cost of transmission capacity in $/kW. Using the capacity contribution of solar calculated by PacifiCorp's in its 2019 Integrated Resource Plan, I estimate the extent to which solar provides energy at peak times, thereby reducing congestion on the transmission system. In contrast, Vote Solar witness Dr. Yang uses PacifiCorp's firm transmission rate as a proxy for avoided transmission capacity.[35] The intuition to his approach is that incremental reductions in peak load would make firm transmission capacity available to other transmission customers. In my opinion, both methodologies are valid ways to estimate avoided transmission capacity. That said, I continue to recommend including an avoided transmission capacity factor of 1.90 cents/kWh in the export credit rate.

Q. Can you please discuss Vote Solar's approach to estimating avoided distribution capacity and provide any recommendations?

A. Yes. Vote Solar estimated avoided distribution capacity using RMP's distribution deferral value for demand-side management and energy efficiency programs. Demand-side investments reduce congestion on the distribution system. To the extent that behind-the-meter solar produces energy during peak times, solar reduces the need to invest in the expansion of the distribution system. I agree with Vote Solar's methodology for estimating this factor, and I recommend the Commission value avoided distribution capacity at 0.52 cents/kWh in the export credit rate.

Q Can you please explain avoided carbon compliance and Vote Solar's estimation?

A. Yes. The avoided carbon compliance value represents the "costs of installing emissions control equipment or retiring a generation facility to reduce carbon emissions".[36] Investment by customers in behind-the-meter solar reduces the carbon emissions from RMP's fleet of

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[35] Revised Affirmative Testimony of Spencer S. Yang, Ph.D., lines 176-178.
[36] Revised Affirmative Testimony of Carolyn A. Berry, Ph.D, lines 773-775.

generating resources. Vote Solar witness Dr. Milligan estimated carbon emissions,[37] and Vote Solar witness Dr. Berry calculated a levelized value of 2.80 ¢/kWh.[38]

Q. What is your recommendation with regard to the cost of avoided carbon compliance?

A. I recommend the Commission include Vote Solar's estimate of avoided carbon compliance costs in the export credit rate.

VIII. OTHER BENEFIT FACTORS

Q. What are your thoughts on the community benefits estimated by Vote Solar?

A. Customer-sited solar has broad benefits to the environment and the economy. The Commission should consider all the benefits that customer-sited solar provides, however the Commission need not quantitatively include those factors in the final export credit rate. The Commission should follow the old adage that "ratemaking is an art, not a science" and set the export credit rate based on quantitative and qualitative factors in the spirit of fully compensating behind-the-meter solar.

Q. How should the Commission address utility-based costs that were not quantified by parties (like ancillary services)?

A. The Commission should consider qualitatively the resiliency and the increased reliability that behind-the-meter solar provides to RMP's grid. Similarly, the market price effect discussed by Vote Solar could prove difficult to quantify, so the Commission should assess that value qualitatively. As for ancillary grid services, I recommend the Commission qualitatively assess the future potential for behind-the meter resources to provide ancillary service. As noted by DPU

[37] Revised Affirmative Testimony of Michael Milligan, Ph.D., lines 615-625.
[38] Revised Affirmative Testimony of Carolyn A. Berry, Ph.D, lines 753-776..

witness Mr. Davis, "the amount and timing of customer generation may prove to be useful in smaller, real-time balancing applications".[39] The Commission should keep in mind that setting the export credit rate too low would shut down the market for behind-the-meter solar in Utah, and therefore reduce the future potential for solar and storage to provide ancillary services and other energy innovations that can provide significant ratepayer benefits.

IX. OTHER ISSUES

Q. Are there other issues raised by parties that you would like to address?

A. Yes. Specifically, I would like to discuss the netting interval, metering and application fees, and the process for future updates of the export credit rate. I find RMP's proposals for these terms to be discriminatory to solar customers, and deeply troubling in their seemingly purposeful intent to infringe on the right of private citizens to invest in their homes. Comparing retail customers with independent power producers that sell wholesale power is a tricky thing to do, but RMP's overall proposal seems to equate excess power from distributed energy resources ("DER") on the distribution system with wholesale power on the transmission system. Yet they would give retail customers harsher terms than those afforded to independent power producers. My recommended principle of "not treat[ing] retail customers like independent power producers" is upheld, but RMP's proposal would treat retail customers worse than independent power producers.

A. Netting interval

Q. What is your opinion on netting intervals proposed by parties?

[39] Direct Testimony of Robert A. Davis, lines 308-310

A. Essentially, there are two proposals on netting intervals: instantaneous netting proposed by RMP and hourly netting proposed by Vivint Solar and other parties. As noted in my Direct Testimony, hourly netting is more appropriate for customer-sited, behind-the-meter solar. Hourly netting would provide a price signal to encourage customers to reduce or increase their load in response to solar production. It is not reasonable to expect net metered customers to tune their energy usage based on real-time energy production. Residential customers invest in solar to help control their energy bill. They do not install solar to sell power to their utility.

Additionally, it is not practical for solar companies to model at increments below one hour when marketing to customers, as there are virtually no data sources that are granular enough to model customer usage profiles or estimated system production on a less than hourly basis. This is especially true for customer usage data, which is only available at the monthly level for most customers and must be extrapolated to hourly profiles. If solar companies cannot model expected usage and production at the proposed netting interval, how are customers expected to understand the implications of the new solar tariff? It would violate the principles of simplicity and transparency for customers who are most accustomed to understanding energy usage on a monthly basis.

Q. Do other parties raise issues with instantaneous netting proposed by RMP?

A. Yes. Utah Clean Energy, the Utah Solar Energy Association, and Vote Solar all support hourly netting. While not addressing hourly netting, OCS witness Cheryl Murray seems to have concerns with instantaneous netting. Ms. Murray stated that OCS will use "bill simplicity and transparency" when supporting proposals.[40] And she raises concerns "that it will be difficult for customer generators to understand how compensation is determined" under RMP's proposal.[41]

[40] Phase II Direct Testimony of Cheryl Murray, lines 58-65
[41] Phase II Direct Testimony of Cheryl Murray, lines 104-106

Q. Do you have other concerns with RMP's instantaneous netting proposal?

A. Yes. Conceptually, instantaneous netting of exports might be able to provide the exports on a real-time basis. The IEEE 1547 standard outlines the requirements to interconnect with the distribution grid. The 2018 update to that standard included requirements that use DER to improve the quality of power on the grid.[42] Some states have begun mandating the installation of "smart inverters" certified to the IEEE 1547-2018 standard so that utilities can use DER to provide grid services like voltage and frequency support.[43] DPU witness Davis seems to contemplate such an approach, stating "the amount and timing of customer generation may prove to be useful in smaller, real-time balancing applications"[44] though he notes that "[t]here remains a lot of work to be done in this area."[45] Vivint Solar has experience in other states such as California, Hawaii, and Massachusetts where smart inverter functionality is a requirement of interconnection and provides power quality support for the grid and would support similar standards in Utah to ensure that DER systems are providing additional value. It's unclear from RMP's testimony if they were contemplating such an approach when recommending instantaneous netting.

Q. Would you support RMP providing compensation to DER for the real-time benefits they provide to the grid?

A. Yes, potentially. Where DER can provide value to the grid for voltage support, frequency support and other services, the DER should be appropriately compensated. The concern in this

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[42] For example, see *Arizona Public Service Solar Partner Program: Advanced Inverter Demonstration Results* https://www.epri.com/research/products/000000003002011316

[43] According to a PV-Magazine.com article, Hawaii, California, Minnesota, and Maryland have adopted smart inverter rules. https://pv-magazine-usa.com/2020/04/08/rooftop-solar-opportunities-expand-with-smart-inverter-rollout/

[44] Direct Testimony of Robert A. Davis, lines 308-310.

[45] DPU Response to Vivint Solar Data Request 1.3(b)

case is that RMP has not provided a compensation mechanism. The export credit rate is a flat value regardless of whether the DER may be providing those grid services. In such a case, DER would provide benefits to the grid that are not compensated, which would result in a shifting of costs. Even if the Commission were interested in smart inverters for grid support services, instantaneous netting is not the right tool to achieve such an end. For these reasons, the Commission should reject instantaneous netting, instead set the netting interval to at least an hourly duration.

B. Metering and application fees

Q. What is your opinion on the meter and application fees proposed by RMP?

A. I support metering and application fees appropriately calibrated to the costs incurred by RMP. However, RMP's calculation of the $150 application fee is problematic and the $160 metering fee is discriminatory.

Q. What are your concerns with the proposed application fee?

A. To be clear, I support the use of reasonable application fees to recover RMP's cost to review, assess, and approve (or deny) applications for interconnection. However, RMP is using average cost pricing to recover the cost of processing all applications for interconnection.[46] This ignores the level of complexity of interconnection requests and shifts the cost of conducting Level 3 interconnection requests to residential customers submitting Level 1 requests to install small systems. While I do not know the full details of how RMP analyzes and approves interconnection applications, Level 1 interconnections generally require a modest amount of time

[46] Direct Testimony of Robert M. Meredith, lines 208-215.

to complete a short checklist of factors that must be considered. In contrast, Level 3 interconnections require a professional engineer conduct an interconnection study, which costs significantly more in terms of the number of hours and the hourly billing rate. Furthermore, in the previous net metering case, Ms. Steward argued that "the average cost of processing a residential net metering application… was about $60".[47] RMP has not provided compelling evidence on why the cost of Level 1 interconnections should be drastically changed.

Q. How do you recommend structuring application fees?

A. Instead of using average cost pricing for all interconnection requests, I recommend RMP use a tiered pricing structure based on the interconnection level. Currently, the application fee for Schedule 136 customers is $60 for Level 1 applications, $75 plus $1.50 per kilowatt of installed capacity for Level 2 applications, and $150 plus $3.00 per kilowatt of installed capacity for Level 3 applications.[48] This tiered approach assigns costs based on the complexity of the application. I recommend RMP provide new cost estimates for tiered application fee.

Q. What are your concerns with the metering fee?

A. RMP has a plan to deploy advanced metering infrastructure ("AMI") meters to some of their customers.[49] By the end of 2022, they estimate 170,000 AMI meters installed on customer premises.[50] No metering fee will be charged to the customers with AMI, and RMP intends to recover the cost of those meters through base retail rates.[51] While I am not familiar with all of the

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[47] Direct Testimony of Joelle R. Steward, lines 687-688.
[48] Rocky Mountain Power Electric Service Schedule No. 136, https://www.rockymountainpower.net/content/dam/pcorp/documents/en/rockymountainpower/rates-regulation/utah/rates/136_Transition_Program_for_Customer_Generators.pdf
[49] Direct Testimony of Robert M. Meredith, lines 238-240.
[50] DPU Response to Vote Solar Data Request 14.1(1)
[51] DPU Response to Vote Solar Data Request 14.1(2) and (3)

details of RMP's plans to deploy AMI, I generally support utilities installing AMI due to the efficiency and operational benefits provided by AMI. However, I oppose RMP's plans to charge a $160 metering fee to solar customers. All customers will benefit from the AMI installed on solar homes and businesses, just like all customers will benefit from the AMI installed on other facilities. When all other AMI will be recovered through base rates, charging solar customers a meter fee is discriminatory. I recommend the Commission not approve RMP's proposed $160 meter fee.

C. Export Credit Rate updating

Q. What is your opinion on RMP's proposed schedule for updating the export credit rate?

A. It is possible that the value of incremental solar on RMP's grid will change, so Commission should review and reassess the export credit rate as market conditions change. RMP proposes annual updating of the export credit rate, with all non-Schedule 135 customers open for changes.[52]

Q. What concerns do you have with annual updating?

A. Allowing the export credit rate to be revised on an annual basis provides no certainty for customers that invest in DER. In my experience, customers are looking for cost savings when they choose to invest in solar. Annual updating throws into question the value of the solar investment in all future years. Customers will not make a twenty year (or longer) investment in a rooftop solar system when the value of the cost savings may change next year and the year after

[52] Direct Testimony of Joelle R. Steward, lines 189-190.

that. As noted in my direct testimony, I recommend the Commission revisit and reassess the value of solar exports every 3 to 5 years to account for changes in market conditions. However, when solar customers first interconnect, they should be locked in to the terms of the export credit rate for 20 years.

X. CONCLUSION

Q. To summarize, what are your recommendations for the Commission?

A. I recommend the following:

- Set the export credit rate at the retail rate based on the export credit components outlined in Table 1.
- The export credit rate should use hourly netting.
- Reassess the export credit rate every 3-5 years, but allow customers to lock in the export credit rate terms when they interconnect.
- The Commission should deny RMP's proposed $160 meter fee.
- The Commission should order RMP to provide new cost estimates for a tiered application fee.

Q. Does this complete your testimony?

A. Yes.

CERTIFICATE OF SERVICE

I hereby certify that on July 15, 2020, a true and correct copy of Vivint Solar's rebuttal testimony of Christopher Worley in Phase 2 of Docket No. 17-035-61 was served by email on the following Parties:

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