Witness OCS – 2R

BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH

	)	
	)	**Docket No. 17-035-61 Phase II**
In the Matter of the Application of	)	
Rocky Mountain Power to	)	**Rebuttal Testimony**
Establish Export Credits for	)	**of Philip Hayet**
Customer Generated Electricity	)	**On behalf of the**
	)	**Office of Consumer Services**
	)	

REDACTED AND PUBLIC VERSION

July 15, 2020

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Introduction and Summary of Positions

Q. WHAT IS YOUR NAME, OCCUPATION AND BUSINESS ADDRESS?

A. My name is Philip Hayet and I am a Vice President and Principal of J. Kennedy and Associates, Inc. ("Kennedy and Associates"). My business address is 570 Colonial Park Drive, Suite 305, Roswell, Georgia, 30075.

Q. PLEASE PROVIDE A SUMMARY OF YOUR QUALIFICATIONS AND EXPERIENCE?

A. I have included a summary of my education, experience, professional certifications, and expert testimony appearances in Exhibit PMH-1.

Q. ON WHOSE BEHALF ARE YOU APPEARING?

A. I am appearing on behalf of the Utah Office of Consumer Services (OCS).

Q. WHAT WAS YOUR INVOLVEMENT IN THE NET METERING DOCKET (14-035-114) THAT PRECEDED THIS DOCKET?

A. Docket No. 14-035-114 was opened to examine the costs and benefits of Rocky Mountain Power's ("RMP") net metering program pursuant to requirements under Utah Code Ann. § 54-15-105.1. I provided testimony in Phase I of that proceeding on behalf of the OCS. The purpose of that proceeding was to "establish the appropriate analytical framework for making the required determinations…"[1] of the costs and benefits of net metering programs. That docket resulted in RMP making a filing that proposed modifications to the Schedule 135 net metering program based on its determination "that the current rate structure for residential

[1] Commission Order, Docket No. 14-035-114, November 21, 2014, at pg. 2, http://pscdocs.utah.gov/electric/14docs/14035114/262159140351 14nocpasc.pdf

net metering customers is unjust and unreasonable because it does not reflect the costs imposed on and the benefits contributed to the system and unfairly shifts costs of net metering customers to other customers."[2] I took a similar position in that proceeding.

Q. WHAT WAS THE OUTCOME OF THAT DOCKET?

A. A comprehensive Settlement Stipulation ("Stipulation") was reached on August 28, 2017, which among other things required RMP to "…file an application to initiate the Export Credit Proceeding to determine the compensation rate for exported power from customer generation systems, including all customers after the expiration of the Grandfathering Period and Transition Period, as applicable."[3] RMP opened this docket on December 1, 2017, and proposed its Export Credit Rate in its direct testimony on February 3, 2020.[4]

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY IN THIS PROCEEDING?

A. First, I address a number of issues associated with RMP's proposed new Schedule 137, Net Billing Program that was presented in RMP witness Robert Meredith's direct testimony. These issues include RMP's proposal to implement real time metering, to allow the proposed expiration of credit balances that can be used by

[2] Direct Testimony of Gary Hoogeveen, RMP, Docket No. 14-035-114, November 9, 2016, at pg. 4, http://pscdocs.utah.gov/electric/14docs/14035114/290025DirTestHoogeveen11-9-2016.pdf

[3] https://pscdocs.utah.gov/electric/14docs/14035114/296270RMPSettleStip8-28-2017.pdf, at pars. 28-31, pg. 9.

[4] The Export Credit Proceeding was bifurcated into two phases, with Phase I determining the load research study plan that was implemented in 2019.

Schedule 137 customers to offset their electric bills, and to include certain rate design issues.

Second, I respond to RMP's and Vote Solar's Export Credit Rate proposals that were discussed in each company's direct testimony. Vote Solar performed extensive analysis in this case, supported by multiple witnesses, and has recommended an Export Credit Rate of $222.2/MWh, or 22.22 cents/kWh, which is substantially greater than RMP's proposal of $15.26/MWh, or 1.526 cents/kWh.[5] Several important methodological issues underlie this enormous difference and this testimony identifies the most important of the methodological issues and assesses the reasonableness of the two approaches. Also, note that Vivant Solar's Export Credit Rate proposal is $92.0/MWh. While Vivant Solar's rate is lower than Vote Solar's, it is still significantly higher than RMP's proposal and equally unacceptable. Since Vivant Solar basically includes the same components in its proposal as Vote Solar, I mainly focus on Vote Solar's proposal because it includes additional benefits not addressed in Vivant Solar's proposal.

Q. PLEASE SUMMARIZE YOUR FINDINGS.

A. In general, the OCS believes that the provisions of the proposed Schedule 137 and RMP's recommended Export Credit Rate methodology are for the most part reasonable. The OCS finds that both Vote Solar's and Vivant Solar's proposed Export Credit Rates are far too high, particularly Vote Solar's recommendation of $222.2/MWh. It is over 14 times greater than RMP's proposed Export Credit Rate and is more than 100% greater than the average residential embedded cost-based

[5] For the remainder of the testimony all energy rates will be expressed on a $/MWh basis.

retail rate of RMP in Utah. Notwithstanding OCS's general opposition to Vote Solar's proposal, there are some adjustments to RMP's methodology that the OCS has identified that the Public Service Commission ("PSC") should adopt that would increase RMP's proposed export credit rate by a small amount, $2.46/MWh (from $15.26/MWh to $17.72/MWh).

Q. HOW IS THE REMAINDER OF YOUR TESTIMONY ORGANIZED?

A. In the remainder of my testimony, I discuss three topics. First, I address Vote Solar's primary recommendation to re-open the Schedule 135 net energy metering ("NEM") program to all existing and new customers, which should be categorically rejected.[6] Second, I discuss some general provisions of Schedule 137, such as RMP's proposal to use real time metering to calculate the export credit payment in its proposed Net Billing program. Third, I discuss the key methodological differences between the RMP and Vivant Solar avoided cost calculations, and provide the OCS's position on these key issues.

Vote Solar's Primary Recommendation

Q. IS VOTE SOLAR'S PRIMARY RECOMMENDATION CONSISTENT WITH THE PSC'S OBJECTIVE TO "DETERMINE THE COMPENSATION RATE FOR EXPORTED POWER FROM CUSTOMER GENERATION SYSTEMS" AS DISCUSSED IN THE PSC'S SEPTEMBER 29, 2017 ORDER APPROVING THE STIPULATION IN DOCKET NO. 14-035-114?

[6] Sachu Constantine direct testimony, March 3, 2020, at ln. 362.

A. No it is not. Vote Solar's primary recommendation in this proceeding is discussed in the Summary of Recommendations portion of witness Sachu Constantine's direct testimony at page 4. Mr. Constantine recommends that the PSC should disregard the Stipulation in Docket No. 14-035-114, which all of the signatories agreed was "just and reasonable in result and will result in rates that are just and reasonable,"[7] and re-open RMP's former NEM program, which ended on November 15, 2017 after the PSC issued its Stipulation Order. Vote Solar appears to be taking the position that the Stipulation was not just and reasonable, and it appears to do this given it was not a signatory to the Stipulation.

Q. DO YOU AGREE WITH VOTE SOLAR?

A. No, and it is not clear why Vote Solar would take this position as in another part of Mr. Constantine's testimony, he acknowledges, as I do, "…that the scope of this docket is limited to the appropriate compensation method for CG exports."[8]

Vote Solar's recommendation to re-open the net metering program appears to be based on Mr. Constantine's assertion that benefits of the net metering program exceed its costs. Vote Solar's recommendation is unreasonable because it only conducted an examination of the benefits of rooftop solar, not all of the costs, and Vote Solar does not address any of the concerns about the net metering program that were examined at length in Docket No. 14-035-114. This includes the concern that Schedule 135 was unjust because net metering customers were overly compensated (paid at the retail rate) and that the net metering program unfairly

[7] Settlement Stipulation, Docket No. 14-035-114, pg. 1, par. 2.
[8] Sachu Constantine direct testimony, March 3, 2020, at ln. 173.

shifted costs from participating to non-participating customers. I disagree that it would be reasonable to re-open the Schedule 135 NEM program, and I believe the PSC should reject Vote Solar's primary recommendation. For the remainder of my testimony, in which I consider Vote Solar's recommendations, I focus on its alternative recommendation proposing an actual Export Credit Rate.

Schedule 137 Issues

Q. PLEASE EXPLAIN YOUR UNDERSTANDING OF RMP'S PROPOSAL TO USE "REAL TIME" ENERGY MEASUREMENTS TO DETERMINE EXPORTED ENERGY.

A. RMP is proposing to change its methodology to calculate the amount of energy delivered from RMP and the amount of energy exported from the customer's own generation. Currently, charges for Schedule 136 energy are determined by netting energy over a 15 minute interval as follows:

a. First, customer generation is used to offset the customer's household usage ("behind the meter netting"). Since RMP's metering measures flows to a customer from the grid ("deliveries") or flows out to the grid ("exports"), customers always receive the full available energy from customer generation to offset their household usage to the extent their usage is the same or less than what is generated at that instant.

b. At any point in time, a customer may be receiving deliveries from RMP (customer household usage exceeds customer generation) or may be exporting to the grid (customer generation exceeds household usage).

c. Under Schedule 136, the total amount of delivered energy is netted against the total amount of exported energy every 15 minutes to calculate a net delivery or a net export (only one of these can occur during any 15 minute period).

d. On a monthly basis, the sum of all 15 minute interval deliveries is billed at the standard tariff rate and the sum of all 15 minute interval exports receives an Export Credit (kWh of exported energy times the Export Credit Rate).

Currently under Schedule 136, the Export Credit Rate has been predefined per paragraph 19 of the Stipulation (referred to as the "Transition Export Credit" in the Stipulation).

Under RMP's proposed Schedule 137, real time metering proposal (also referred to by RMP as the "Net Billing Program"), step (c) above will be eliminated, as no interval netting will be performed. Rather, the total amount of delivered kWh for the month will be billed at the standard tariff rate and the total amount of exported kWh will be paid an Export Credit based on the proposed Export Credit Rate determined in this proceeding. The Export Credit will be applied to the customer's bill as an offset to the total charges, other than the customer service charge, which RMP has proposed cannot be offset by the Export Credit.

Q. BASED ON YOUR REVIEW OF RMP'S PROPOSAL, DO YOU AGREE WITH THE PROPOSED CHANGE TO A REAL TIME BILLING METHOD?

A. Yes. The OCS agrees with RMP's real time Net Billing proposal. Solar customers will continue to be able to offset a portion of their otherwise applicable electric charges (other than the monthly customer charge) with customer generation, while receiving Export Credits for the full amount of exported energy. In fact, solar customers could possibly offset up to 100% of their electric charges (other than the monthly customer charge) if they include battery storage as part of their installation. The current 15 minute interval netting methodology permits solar customers, within the 15 minute interval, to offset RMP energy deliveries with customer generation that occurs at a different moment in time, as long as both occur within the 15 minute interval. There is no basis for such intra-15 minute netting to occur. To the extent

that RMP provides net deliveries to the customer over perhaps the first 5 minutes of a 15 minute interval, excess customer generation in the next 5 minute period (within the 15 minute interval) does not avoid the actual costs RMP incurred associated with the prior 5 minute delivery. As such, the customer should be charged for delivered energy in one period, irrespective of the amount of customer generation that occurs in a subsequent period. Therefore, the OCS supports RMP's real time Net Billing proposal.

Q. SCHEDULE 137 PERMITS A PARTICIPATING CUSTOMER TO OFFSET THE CUSTOMER'S OTHERWISE APPLICABLE MONTHLY ELECTRIC CHARGES USING EXPORT CREDITS, EXCEPT FOR THE MONTHLY CUSTOMER SERVICE CHARGE. IS THIS A REASONABLE PROVISION?

A. Yes. The OCS agrees with RMP that this provision reduces cross-subsidies between solar customers and non-participating customers. The standard tariff customer service charge reflects customer billing costs, the costs of a meter and some additional fixed costs associated with generating a bill, none of which are avoidable by solar generation as long as the customer is connected to the grid and receives a monthly bill from RMP.

Q. RMP PROPOSES THAT UNUSED EXPORT CREDITS ROLL OVER FROM ONE MONTH TO THE NEXT WITH AN EXPIRATION PROVISION. IS THIS A REASONABLE PROVISION?

A. Yes. Under RMP's proposal, the Export Credits will accrue such that any unused amounts in one month will be carried forward to the next month until March (or

October in the case of irrigation customers) of each year, at which point, the balance will be eliminated. This is similar to a tariff provision that has existed in both Schedule 135 and 136, and the OCS has generally supported the Schedule 137 tariff provision that limits the carryover of Export Credit balances for the same reason as cited by RMP in this case. As RMP witness Meredith explains, the objective of the RMP's Net Billing Program is for customers to "appropriately size their generation systems to match actual usage" and "not for a customer to become a power producer."[9] A major difference between the two is that power producers are bound by contractual provisions that address availability, credit, maintenance, etc., which do not apply to customer generators.

In addition, the OCS believes this is reasonable, particularly in the event that the PSC decides to permit the payment of even partial avoided capacity cost components in the Export Credit Rate computation. Avoided capacity cost components increase the reliance of RMP and all customers on the availability of solar capacity. Limiting the excess sizing of such solar capacity, through the imposition of an expiration provision, would serve to reduce this risk to non-participants.

Q. RMP PROPOSES TO DIFFERENTIATE THE EXPORT CREDIT RATE SEASONALLY AND BY TIME OF USE PERIODS (ON- AND OFF-PEAK). DO YOU BELIEVE THAT SEASONAL DIFFERENTIATION IS REASONABLE?

[9] Robert Meredith direct testimony, March 3, 2020, at ln. 155.

A. Yes. RMP proposes a summer period rate based on avoided energy cost during June through September and a winter period rate during the months of October through May. Although the Company's Schedule 2 Residential Service Optional Time of Day Rider includes May as a summer month, the Company is proposing to include May in the winter season for purposes of the Net Billing program. While there may be other issues to consider in deciding if May should be included in the summer period, this decision will not result in a material impact on the overall payments to solar customers for exported energy since the seasonal rates are designed to produce an average $15.26/MWh rate on an annual basis. Under RMP's methodology, the annual avoided energy cost is adjusted to seasonal and on/off peak values with a constraint that the final average Export Credit Rate should be equal to $15.26/MWh in 2021. Thus, if May were reassigned to the summer period, this would cause a modest increase in the summer period Export Credit Rate and a small decrease in the winter period rate.

Furthermore, according to RMP's results (Exhibit DJM-1), the average Export Credit Rate value for May 2021 is $12.25/MWh, which would be more consistent to include with the other winter month values. For example, the May value of $12.25/MWH is in between March ($13.96/MWh) and April ($11.07/MWh), but if it were included as a summer month, it would be the lowest of all summer values. Therefore, it would be reasonable to include May as one of the winter months for purposes of the Export Credit Rate calculation.

Q. DO YOU HAVE ANY OBJECTIONS TO RMP'S PROPOSED ON/OFF PEAK DIFFERENTIALS?

A. No. RMP is proposing separate on and off-peak rates for each season, following the same basic methodology used to determine seasonal rates. As in the seasonal rate determination, the on/off-peak prices are developed such that they produce the annual average Export Credit Rate of $15.26/MWh, based on assumed average export energy pattern. This is reasonable because to the extent that a customer can modify its exported energy, by changing its household energy usage, the customer can change the average total amount it receives for exported energy. As such, the seasonal and on/off-peak rates do provide price signals that can impact behavior.

A small change in seasonal definitions or on/off-peak hours should not have a material impact on the total compensation to solar customers from exported energy because the weighted average annual revenues would always be based on RMP's calculated $15.26/MWh average annual avoided energy cost. All in all, the OCS does not have an objection to RMP's proposed designated months or on/off-peak hours.

Export Credit Rate Issues

Q. WHAT ARE THE MAIN PRINCIPLES THAT YOU RELIED ON IN EVALUATING THE EXPORT CREDIT RATE ISSUES RAISED BY BOTH RMP AND VOTE SOLAR?

A. First, I relied on the OCS positions discussed in Cheryl Murray's March 3, 2020 direct testimony in this case.[10] The primary intent of customer generation is to

[10] Cheryl Murray direct testimony, lines 60-63. OCS witness Michele Beck discusses Ms. Murray's second principle in her rebuttal testimony.

provide participating customers an opportunity to offset their otherwise applicable household or business usage. Under RMP's Schedule 137 proposal, solar customers will have the opportunity to offset a portion of their monthly bill except for the monthly customer charge, as discussed above. As such, for much of the customer's solar generation, the customer will be paid, implicitly, the full embedded cost of energy (e.g., fuel, purchased energy, variable O&M), embedded generation capacity cost, embedded transmission capacity cost, embedded distribution capacity cost, embedded A&G cost and embedded customer costs not included in the customer service charge. This case is only about the amount of money that will be paid to solar customers for excess generation (net exported energy) that is generated above the level needed to cover the customer's own energy usage as determined on a real-time basis.

In developing its response, the OCS has relied on the principle that costs and benefits must be (i) reasonably quantifiable and (ii) accrue to the utility or its non-net metering customers. The PSC's prior decisions regarding the valuation of exported energy support this principle. In particular, the PSC's Conclusion of Law on Statutory Interpretation and Order Denying Motion to Strike issued in in the earlier net metering case stated, "the Commission makes the following conclusion of law: for purposes of performing the analysis under Utah Code Ann. § 54-15-105.1(1), the relevant costs and benefits are those that accrue to the utility or its non-net metering customers in their capacity as ratepayers of the utility."[11] While paragraph 30 of the Stipulation may state that nothing from Docket No. 14-035-

[11] PSC Order, Docket No. 14-035-114, July 1, 2015, at pg. 17.

114 will "…..be precedential in the Export Credit Proceeding or any future case,"[12] that does not mean that parties cannot continue to support that principle or that the PSC will be swayed from believing that principle. The OCS continues to recommend that costs or benefits that do not directly affect the utility's cost of service should not be included in the calculation of the Export Credit Rate.

Q. WHAT ARE THE KEY ISSUES THAT YOU HAVE IDENTIFIED THAT DIFFERENTIATE RMP'S EXPORT CREDIT RATE FROM VOTE SOLAR'S EXPORT CREDIT RATE?

A. As noted above, Vote Solar's Export Credit Rate is over 14 times greater than RMP's rate. The difference between these values is primarily due to the following factors:

1) Avoided Energy Costs
    a. RMP used its Generation and Regulation Initiative Decision ("GRID") model to calculate avoided energy costs for 2021, while Vote Solar performed a calculation based on the average expected market prices at three of RMP's eastern market hubs.
    b. RMP calculated its avoided energy cost for a single year and proposes annual updates. Vote Solar derived its estimate based on a 20-year levelized calculation.
2) Avoided Line Losses – RMP excluded secondary voltage line losses in its avoided cost loss factor calculation. Vote Solar included these losses.
3) Integration Costs – RMP includes integration costs. Vote Solar does not include this.
4) Avoided Capacity Costs - RMP excluded generation, transmission, and distribution avoided capacity cost components in its calculation. Vote Solar included all three of these avoided capacity cost components.
5) Other Benefits – Vote Solar included CO_2 compliance costs and other benefits of CO_2 reductions, health benefits from reduced air pollution, fuel

[12] Stipulation in Docket No. 14-035-114, August 28, 2017, at pg. 10.

hedging benefits, and local economic benefits in its export credit calculation. RMP excluded all of these potential benefits in its calculation.

Q. PLEASE DISCUSS THE AVOIDED ENERGY COST DIFFERENCES.

A. RMP used the GRID production cost model to estimate its avoided energy cost, which accounted for about 95% of its 2021 total Export Credit Rate. RMP estimated its avoided energy cost using the Proxy/Partial Displacement Revenue Requirement Methodology ("PDDRR") that has been approved by the PSC for calculating avoided energy cost pursuant to Schedule 37 payments to Small QFs. RMP used the GRID model from its January 2020 filing in Docket No. 19-035-18, updated to incorporate market prices from the December 31, 2019 Official Forward Price Curve ("OFPC").

RMP calculated avoided energy cost for 2021, with and without an assumed level of Utah rooftop solar installations. Vote Solar performed a calculation of avoided energy costs without the aid of a production cost model, using only estimated market hub price data for the Four Corners, Mead and Mona market hubs. Vote Solar used market price data from RMP's September 31, 2019 OFPC, which was an earlier vintage than what RMP used in its GRID analysis. The assumption that underpinned Vote Solar's calculation of the value of exported energy was that all of the exported energy could be sold at the three market hubs on an unconstrained basis. Furthermore, Vote Solar assumed that customer generators would receive a fixed payment rate for 20 years based on a levelized cost calculation derived over the period of 2021 to 2040 for its avoided energy costs. Using GRID, RMP calculated its 2021 average avoided energy cost to be

$15.26/MWh (including losses and an integration cost adjustment), while Vote Solar calculated a 20-year levelized avoided energy cost of $38.59/MWh, more than double RMP's avoided energy cost estimate. Even if Vote Solar had derived its avoided energy cost on a one-year basis for 2021, not levelized over 20-years, Vote Solar's 2021 avoided energy cost would have been **CONFIDENTIAL INFORMATION BEGINS** $[redacted]/MWh,[13] **CONFIDENTIAL INFORMATION ENDS** which is still **CONFIDENTIAL INFORMATION BEGINS** [redacted]% **CONFIDENTIAL INFORMATION ENDS** greater than RMP's calculation for 2021.

Q. IS RMP'S CALCULATION OF AVOIDED ENERGY COST ASSOCIATED WITH NET EXPORTED ENERGY REASONABLE?

A. For the most part, yes, though I do have one issue with RMP's GRID assumptions that I discuss below. For the sake of comparison, I focus on RMP's 2021 avoided energy cost estimate versus Vote Solar's non-levelized 2021 avoided energy cost estimate. Vote Solar performed a relatively straightforward spreadsheet analysis by weighting the average of the three hourly sets of hub market price projections (defined by the average market price at the Four Corners, Mead and Mona market hubs) for 2021, by the hourly expected solar generation. Vote Solar assumed that any exported solar energy produced could be sold in the market or alternatively, could allow RMP to avoid purchasing energy at the market hubs up to the full amount of the exported energy. Conceptually, this is a logical methodology;

[13] Though this value and others are noted as being confidential, the values are aggregated numbers and are not clearly confidential. However, out of an abundance of caution we are labeling them so.

however, it does not consider the impact of constraints, such as transmission limits in the System.

In contrast, RMP compared two GRID production cost runs; one with rooftop solar (9,000 assumed installations at 4.5 kW each with an export energy capacity factor of 14%), and one without. The difference in cost between the two model runs divided by the solar MWh resulted in RMP's estimate of avoided energy cost for 2021. Absent constraints, the RMP and Vote Solar calculations should not be significantly different since the market hubs would reflect the marginal cost to the System associated with the additional exported solar energy.

Q. DID YOU PERFORM ANY ANALYSES TO EXPLAIN THE DIFFERENCES BETWEEN THE TWO ESTIMATES OF AVOIDED ENERGY COSTS?

A. Yes, two types of analyses were performed to determine the cause of the significant difference in the two estimates. The first analysis consisted of an examination of RMP's OFPC data which were input into GRID versus the OFPC data that Vote Solar relied on for its analysis. Recall that RMP relied on a more updated OFPC in its GRID analysis compared to what Vote Solar (December 31, 2019 vs. September 31, 2019) used in its spreadsheet analysis. We performed the same spreadsheet analysis that Vote Solar had performed, but instead of using the September 31, 2019 OFPC data that it used, we used the December 31, 2019 OFPC data that RMP used in GRID. Based on Vote Solar's methodology using the GRID OFPC data, the avoided energy cost result for 2021 was **CONFIDENTIAL INFORMATION BEGINS** $[redacted]/MWh **CONFIDENTIAL INFORMATION ENDS**

(including losses), which was a little higher than Vote Solar's result of **CONFIDENTIAL INFORMATION BEGINS** $[redacted]/MWh **CONFIDENTIAL INFORMATION ENDS** (including losses). Since we were able to derive results using Vote Solar's spreadsheet model with RMP's updated market hub price data that were similar to Vote Solar's results (using an earlier vintage OFPC), we realized that the source of the difference in Vote Solar's and RMP's avoided energy costs had to be due to constraints modeled in GRID.

Q. DID YOU PERFORM ANY GRID ANALYSES TO IDENTIFY THE SOURCE OF THE DIFFERENCE IN THE TWO AVOIDED ENERGY COST ESTIMATES?

A. Yes, we conducted a series of GRID runs and found that transmission and market depth constraints modeled in GRID caused RMP's avoided energy costs to be so much lower than Vote Solar's results. By eliminating both transmission constraints and market depth constraints in GRID we determined that RMP's avoided energy cost increased significantly to $25.53/MWh (without losses), which was very close to Vote Solar's unconstrained 2021 value of **CONFIDENTIAL INFORMATION BEGINS** $[redacted]/MWh **CONFIDENTIAL INFORMATION ENDS** (without losses). This result indicates that in order for GRID to determine avoided energy costs similar to what Vote Solar produced, RMP would need unconstrained access to market hubs.

Q. WOULD IT BE REASONABLE TO CALCULATE AVOIDED ENERGY COSTS EITHER BY COMPLETELY REMOVING CONSTRAINTS IN

GRID, OR USING VOTE SOLAR'S UNCONSTRAINED WEIGHTED AVERAGE MARKET HUB APPROACH?

A. Definitely not, completely removing constraints in GRID or relying on Vote Solar's unconstrainted weighted average market hub approach would be completely unrealistic. Transmission limits are real, do constrain the actual operation of PacifiCorp's generation resources, and should be reflected in the GRID model.

Q. IN ADDITION TO TRANSMISSION CONSTRAINTS, YOU ALSO MENTIONED MARKET DEPTH CONSTRAINTS. PLEASE EXPLAIN WHAT THOSE ARE.

A. In the early to mid-2000 time period, RMP introduced market depth constraint modeling in GRID, also referred to as "market caps", as a means of limiting energy sales to market hubs in an attempt to get GRID results to line up more closely with actual operational results. In an avoided cost proceeding in 2005, the PSC issued an order that permitted PacifiCorp to include market cap modeling to ensure that its coal units would be able to back down to a minimum operating level overnight instead of making excessive sales to the market during those night-time hours. In that Order the PSC stated:[14]

> "We are persuaded by the evidence that coal resources are backed down in some hours and use of a production cost model, including market caps, is necessary to accurately identify the production costs avoided by a QF and thereby maintain ratepayer neutrality."

PacifiCorp contended at the time that such constraints were necessary to prevent coal units from operating excessively in Low Load hours (also referred to

[14] Commission Order, October 31, 2005, Docket No. 03-035-14, pgs. 12 and 13.

as graveyard hours).[15] The input essentially acted as another transmission limit that prevented sales to the market hubs during the Low Load night-time hours.

Q. DID YOU CONDUCT ANY ANALYSIS FOCUSED ON MARKET CAPS?

A. Yes, as mentioned, market caps were originally justified on the basis of needing to limit coal-fired generation during Low Load (graveyard) hours. Even if market caps are still appropriate now, they should only be modeled during Low Load hours, which was the reason that the PSC permitted PacifiCorp to include them in the first place. Given that this export credit proceeding is intended for the purpose of determining an appropriate export credit for solar resources, which primarily operate during on-peak hours, it is especially inappropriate to include market caps during on-peak hours. Furthermore, in OCS 7.4c, RMP was unable to explain about the history of the factors that originally led to the need for the market cap modeling in GRID and it indicated that it has not performed any recent benchmarking of the market cap assumptions.

When we removed the market caps on all markets during the High Load hours but left them in place during the Low Load Hours, RMP's avoided energy cost result (without losses) increased from $14.45/MWh to $16.31/MWh, which reflects about a 13% increase in the avoided energy cost. We believe this is a reasonable modeling change and recommend that RMP be required to include it in its export credit analysis.

[15] Graveyard hours are discussed in Mr. Gregory Duvall's rebuttal testimony for PacifiCorp, Docket 09-035-23, November 12, 2009 at ln. 174.

Q. WOULD YOU ADDRESS THE NEXT KEY ISSUE THAT YOU IDENTIFIED EARLIER, WHICH IS WHETHER THE EXPORT CREDIT RATE SHOULD BE BASED ON A SINGLE YEAR AVOIDED ENERGY COST AS RMP PROPOSES, OR A 20-YEAR LEVELIZED AVOIDED ENERGY COST, AS PROPOSED BY VOTE SOLAR?

A. In theory, if there were no forecast errors, a single year rate and a 20-year levelized rate would produce identical impacts over a 20-year period. Solar customers would receive identical payments for their exported energy on a net present value basis and non-participating customers would pay the same costs to support rooftop solar generation. However, forecasts are not error free. Furthermore, we believe that the risk of a 20-year levelized rate paid to solar customers who have not committed to a 20-year supply agreement is asymmetrical and unduly burdens non-participating customers. Under Vote Solar's proposal, a solar customer in 2021 would receive the levelized Export Credit Rate for 20 years. However, such a customer is under no obligation to provide solar generation for the full 20 years, or any lesser period. In contrast, a small power producer QF must enter a contract of no more than 15 years pursuant to Schedule 37 and according to RMP, "a QF would face potential damages for failing to deliver[y] energy and/or capacity according to the terms negotiated."[16]

Without a contractual obligation requiring the customer to provide exported energy, up-front payments that occur with a levelized rate are potentially unfair to non-participating customers. Under RMP's proposal, the avoided energy cost

[16] RMP response to OCS 10.4.

would be updated annually. Under this arrangement, both solar customers and non-participating customers would bear similar forecast risks.

Q. ARE THERE ANY OTHER REASONS TO UPDATE COSTS ON AN ANNUAL BASIS?

A. Yes, annual updates would allow new costs to be introduced into the Export Credit Rate calculation as they go into effect. As discussed above the OCS supports the principle that only the relevant costs that actually accrue to the utility should be included in the calculation of export credits that will be paid to customer generators. Since CO_2 costs are not actual costs that the utility incurs at this time, the OCS does not believe they should be included in the Export Credit Rate calculation. That said, the OCS could consider supporting the inclusion of carbon compliance costs in the Export Credit Rate -- once such costs actually exist. If in the future a national carbon tax is imposed, then avoided energy costs would increase due to the tax. Setting the Export Credit Rate based on a 20-year levelized projection today as Vote Solar proposes would not result in a carbon tax component being included in the avoided energy costs right now. However, an annual calculation, as proposed by RMP, would allow the inclusion of such a tax component in the future if the tax were actually imposed. For these reasons, the OCS supports RMP's proposal to update its Export Credit Rate on an annual basis.

Q. PLEASE ADDRESS THE AVOIDED LINE LOSS ISSUE.

A. Both RMP and Vote Solar include avoided line losses in their Export Credit Rate calculations. While there are differences between the two calculations, both are based on the same RMP line loss study results. RMP calculated avoided line losses

based on a 2009 Utah area study and used load flow analyses to develop marginal losses. Vote Solar has accepted these values for use in its avoided cost calculations. However, RMP argues that solar rooftop generation does not avoid secondary line losses and, therefore, has excluded these losses from its avoided cost calculation. Vote Solar, on the other hand, includes secondary transformation losses.

At page 7 of his testimony, RMP witness Daniel MacNeil argues that rooftop solar energy,

> "….must be transformed across the secondary distribution system to other customers. As a result, they will incur some line losses and will not be avoiding the entire line losses associated with serving load on the secondary distribution system. Therefore, the Company proposes crediting exports for only avoiding the next higher level, i.e. primary line losses."

RMP's argument is that energy generated at a customer's location on the secondary system will still incur line losses even if it serves another customer on the secondary system because such energy will need to be transformed before it reaches this other hypothetical secondary customer. The energy will also incur secondary line losses as part of this process. Vote Solar argues that the exported energy will likely serve another customer on the same secondary line, and therefore secondary transformation losses are avoided.

Q. WHAT IS THE IMPACT OF THIS LINE LOSS ISSUE ON AVOIDED ENERGY COST?

A. It is relatively small. The Vote Solar line loss expansion factor for energy is 1.0862, while the RMP factor is about 1.0666. The big difference between Vote Solar's avoided line loss cost of $3.10/MWh and RMP's avoided line loss cost of $0.96/MWh is that the Vote Solar energy loss factor is applied to Vote Solar's 20-

year levelized avoided energy cost, which is significantly greater than RMP's one-year avoided energy cost. If Vote Solar's line loss factor is applied to RMP's avoided energy cost instead of being applied to Vote Solar's avoided energy cost, the impact is a small increase in the avoided energy cost rate of just $0.28/MWh ((1.0862 – 1.0666) * $14.45). The OCS recommends using Vote Solar's line loss factor, but only applied to an annual avoided energy cost calculation.

Q. WHAT IS YOUR POSITION ON THIS AVOIDED LINE LOSS ISSUE?

A. It is reasonable to assume that exported energy avoids secondary transformer losses and should be included in the avoided cost calculation. Vote Solar's line loss factor appears to be a reasonable measure of avoided line losses though it should only be applied to a one-year estimate of avoided energy costs not Vote Solar's preference for a 20-year levelized avoided energy cost calculation.

Q. PLEASE ADDRESS THE INTEGRATION COST ADJUSTMENT THAT RMP HAS MADE.

A. As explained in Mr. MacNeil's testimony at page 8, this issue concerns a proposed offset to avoided energy costs resulting from the additional operational costs that RMP has determined that solar resources will impose due to RMP having to maintain additional flexible reserves in its System operations. The integration cost adjustment, which reduces avoided energy costs by $0.15/MWh was determined in RMP's most recent Flexible Reserves Study that was presented in its 2019 IRP. The integration offset of $0.15/MWh is fairly insignificant and does not appear to be unreasonable and I have not identified any problem with this adjustment. This should be reviewed again in the future as additional intermittent resources are added

to the System, and I recommend integration costs be reviewed as RMP updates its Export Credit Rate on an annual basis.

Q. PLEASE DISCUSS YOUR POSITION REGARDING THE INCLUSION OF AN AVOIDED GENERATION CAPACITY COST COMPONENT IN THE EXPORT CREDIT RATE PAID TO CUSTOMER GENERATORS.

A. This issue, and the next two issues associated with the inclusion of an avoided capacity cost for transmission and distribution, comprise a significant component of both Vote Solar's and Vivant Solar's Export Credit Rate calculation. RMP did not include any assumed avoided generation capacity cost in its proposed Export Credit Rate because it argues that exported energy is non-firm and no future capacity would be avoided or deferred. In contrast, Vote Solar proposes a significant avoided generation capacity cost ($14.8/MWh), based on a 20-year levelized avoided cost calculation. In the case of Vivant Solar, nearly half its total Export Credit Rate of $92.0/MWH, is associated with avoided generation and transmission cost components, $41.20/MWH.

Focusing on Vote Solar, its primary argument is that generation capacity is avoided by solar generation up to the capacity value of solar, which Vote Solar calculates to be 27.65% of the nameplate kW rating of a rooftop solar facility. RMP takes the position that it is not reasonable to assume that, for reliability planning purposes, the exported energy (the net of customer generation and household usage) will reliably provide capacity when it is needed to serve RMP Utah customers.

Q. IS RMP'S POSITION REASONABLE?

A. Yes, unlike central station solar, exported energy has a potentially greater level of uncertainty regarding its load carrying capabilities. Moreover, generation capacity avoided cost is generally based on an assumed long-term commitment. For example, RMP may have entered into a 15-year power purchase agreement ("PPA") with a solar supplier who is obligated to maintain and provide capacity by virtue of its long-term contract. No such contractual obligation exists for rooftop solar exported energy. If a customer increases its household usage, all else being equal, exported energy would decline. In fact, exported energy could decline disproportionately if the additional household usage occurred primarily during hours coincident with solar generation.

Q. HOW DID VOTE SOLAR DERIVE ITS RECOMMENDED AVOIDED GENERATION CAPACITY COST?

A. Vote Solar proposes a traditional 20-year levelized avoided generation capacity credit be included in its Export Credit Rate calculation. The methodology used by Vote Solar in its analysis, as discussed by its witness Michael Milligan, is a traditional approach to calculate a solar resource capacity cost, and it accounts for the capacity value of the solar resource compared to a conventional dispatchable resource. Mr. Milligan assumed the average solar capacity value is 27.65% based on nameplate capacity, which reflects the fact that solar resources are not strictly dependable capacity resources that can be relied on to operate at maximum output in all hours. The solar capacity value is used to determine the solar avoided capacity cost assuming that a combined cycle gas turbine ("CCGT") can be avoided as a result of exported energy. While Mr. Milligan's calculations may not be an

unreasonable means of performing the calculation, the applicability of the resulting avoided cost credit to exported energy imposes a risk on non-participating RMP customers that makes it unreasonable. As discussed above, there is no obligation imposed on a solar customer to provide any level of exported energy for any given year. Whether RMP can reasonably assume that the exported solar generation profile used by Mr. Milligan will actually materialize is a risk that has not been factored into the Vote Solar analysis.

Q. SHOULD THE PSC DECIDE TO ADOPT AN AVOIDED GENERATION CAPACITY COST COMPONENT, DO YOU HAVE ANY RECOMMENDATIONS?

A. Yes, but to be clear, the OCS' primary recommendation is not to include an avoided generation capacity cost component for the reasons I described above. However, there is one reason that possibly supports the inclusion of an avoided generation capacity cost component and mitigates the risks of solar generation as mentioned above. The reason is that generation capacity, as opposed to transmission and distribution capacity, is a product that can be readily acquired from the market. For planning purposes, RMP relies on the notion that short term capacity purchases can be obtained from the market. In fact, PacifiCorp's 2019 IRP action plan includes an action item that notes steps it has to take to in order to acquire market capacity purchases.[17] If PacifiCorp had reason to believe that capacity would not

[17] 2019 Integrated Resources Plan, PacifiCorp, Volume 1, p. 26 , October 18, 2019, https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificorp/energy/integrated-resource-plan/2019_IRP_Volume_I.pdf.

materialize, it could arrange for a short term firm purchase in accordance with its Front Office Procedures and Practices.

Again, the OCS does not recommend including a generation capacity component, but if the PSC decides to include one, then the OCS recommends that it be heavily discounted to account for the risk that solar customers have no obligation to provide capacity to RMP. Because exported energy is riskier than a central station solar facility, at most, if an avoided generation capacity cost component is included, it should be included at a discounted percentage of the Vote Solar calculation – maybe 25% to 50% of the calculated value. Note, this assumes that the PSC also adopts Vote Solar's recommendation for using a capacity contribution value of solar factor as discussed above, which accounts for the risk that solar resources are intermittent and may not produce energy during peak hours. Thus, if the Commission decides to include an avoided generation capacity cost component in the Export Credit Rate, the OCS recommends that both the capacity value of solar factor (27.65%) and a second discount factor due to the lack of a customer contractual commitment of between 25% - 50% should be applied in the avoided generation capacity cost calculation.

Q. DID RMP INCLUDE AN AVOIDED TRANSMISSION CAPACITY COST COMPONENT IN ITS PROPOSED EXPORT CREDIT RATE?

A. No, RMP did not include any assumed avoided transmission capacity cost in its proposed Export Credit Rate, presumably for the same reasons that it rejected the inclusion of an avoided generation capacity cost in its calculation, i.e., exported energy is non-firm and no future capacity would be avoided or deferred. In

contrast, Vote Solar proposes a significant avoided transmission capacity cost ($13.4/MWh, including losses), based on a 20-year levelized avoided transmission capacity cost calculation. Vote Solar's avoided transmission capacity cost is based on the same 27.65% capacity value for solar generation but uses an embedded cost estimate of avoided cost based on PacifiCorp's Open Access Transmission Tariff ("OATT") transmission charge of $32.74/kW-year.

While RMP's testimony does not explicitly discuss this issue, RMP's position appears to be that exported energy is non-firm. As such, it would not be appropriate to include an avoided cost component reflecting avoided transmission capacity. Moreover, unlike generation capacity that can be obtained in a relatively liquid market, RMP cannot purchase transmission capacity within its zone in a liquid market. This means that if the exported energy does not, in fact, materialize, RMP would not immediately be able to obtain alternative transmission resources. In particular, since rooftop solar exported energy is not provided by customers pursuant to any long term contractual commitment by the customer, it would not be reasonable for RMP to rely on this exported energy as a source of reliable transmission capacity. Thus, avoided transmission capacity costs should not be included in the Export Credit Rate.

Q. DO YOU HAVE ANY OTHER CONCERNS WITH VOTE SOLAR'S AVOIDED TRANSMISSION CAPACITY COST?

A. Yes. Vote Solar's avoided transmission cost calculation of $13.4/MWh credit is almost as large as RMP's entire proposed Export Credit Rate of $15.26/MWh. I have a number of concerns with Vote Solar's proposal. First, the avoided cost

calculation is based on PacifiCorp's OATT transmission price, which is a fully loaded embedded cost rate that includes such costs as general plant and administrative and general expenses, as well as the average embedded revenue requirements of the entire System's transmission network. Even if an avoided transmission capacity cost component should be included in the Export Credit Rate, which it should not, this is not an appropriate calculation for the avoided transmission capacity cost.

Second, Vote Solar has not performed any analysis to determine the level of transmission investment that could actually be avoided by exported rooftop solar generation. Vote Solar witness Spencer Yang, who supports its avoided transmission capacity cost calculation argues that exported rooftop solar generation likely serves neighboring customers, thus avoiding the need for transmission facilities (and most distribution facilities). While this may possibly be true for energy, it is not true for transmission capacity. At times when exported energy is not available, either because of a lack of solar generation, because the solar customer's household usage consumes all or most of the generation, or because the customer does not properly maintain its solar system, transmission capacity must still be available. At such times, RMP must have sufficient transmission capacity to serve those neighbors, and possibly the solar customer as well. If RMP were to avoid constructing sufficient transmission capacity, some of these loads would not be served.

Furthermore, Vote Solar did not perform any transmission analyses to determine the impact on transmission system reliability if its assumed avoided

transmission capacity is not available. However, in its response to OCS 2.10, Vote Solar did acknowledge that utilities must follow the "North American Electric Reliability Corporation's ("NERC") Reliability Standards and other applicable regional and local reliability criteria to ensure the system reliability." Correspondingly, in response to OCS 9.1, RMP indicated that "PacifiCorp is required to comply with approximately 84 North American Electric Reliability Corporation (NERC) reliability standards, six Western Electricity Coordinating Council (WECC) regional reliability standards, and 16 WECC criteria standards." Given these reliability requirements that must be evaluated, and the risk of not having appropriate transmission capacity, it is simply not reasonable to assume that customer rooftop generation exports would allow RMP to avoid transmission investment. Therefore, the OCS does not believe that an avoided transmission capacity cost component should be included in the Export Credit Rate.

Q. WOULD YOU PLEASE DISCUSS THE ISSUE OF WHETHER AN AVOIDED DISTRIBUTION CAPACITY COST SHOULD BE INCLUDED IN THE EXPORT CREDIT RATE PAID TO SOLAR CUSTOMERS?

A. As is the case for both generation and transmission, RMP does not include any avoided distribution capacity cost in its proposed Export Credit Rate, likely for the same reason – exported energy is non-firm. Again, as is the case with transmission, and perhaps even more significantly, RMP cannot purchase localized distribution capacity in the "market" if the exported energy does not materialize on any given day or hour. Given that rooftop solar exported energy is not provided by customers pursuant to any long term contractual commitment by the customer, it would not

be reasonable for RMP to rely on this generation as a source of reliable distribution capacity. This risk increases significantly with distribution facilities closest to a customer's meter (service drop, secondary lines, line transformers, some primary line facilities).

Vote Solar's avoided distribution capacity cost is based on the value of estimated deferred distribution investment in Utah, adjusted for the 27.65% capacity value of solar. This is calculated to be $13.24/kW-year. This value is then converted to a $/MWh value, then escalated and levelized over a 20-year period to produce a levelized $5.2/MWh avoided distribution capacity cost.

Q. WHAT IS YOUR POSITION ON THE INCLUSION OF A DISTRIBUTION CAPACITY COST COMPONENT IN THE EXPORT CREDIT RATE?

A. I believe that it would be inappropriate to include an avoided distribution capacity cost component in the Export Credit Rate calculation. The Vote Solar analysis relies on a calculation based on an estimate of deferrable distribution investment that could be attributable to exported energy. As discussed with regard to the risks of foregoing transmission investment, foregoing distribution investment under the assumption that some distribution facilities will no longer be needed due to exported energy creates an additional risk to customers that is not justified. If exported energy is not available due to either higher household usage on peak days absorbing a larger share of solar generation, reduced solar generation due to weather conditions, or the unavailability of solar capacity due to a lack of customer maintenance, customer demands on the distribution system are likely to continue to occur. Absent sufficient distribution facilities, those demands will not be met.

Given this risk, it is highly questionable whether there would be any material change in RMP's distribution investment as a result of additional rooftop solar exported energy. Furthermore, there will likely be costs imposed on the distribution system due to customer generation caused by bi-directional flows and those costs would act to offset any distribution cost savings, if in fact there were any. Therefore, the OCS does not believe that an avoided distribution capacity component should be included in the Export Credit Rate.

Q. PLEASE DISCUSS THE FINAL MAJOR DIFFERENCE BETWEEN RMP'S PROPOSED EXPORT CREDIT RATE AND THE RATE PROPOSED BY VOTE SOLAR.

A. Over 65% of Vote Solar's proposed Export Credit Rate of $222.2/MWh is due to the inclusion of additional benefits, none of which were included in RMP's calculation. Vote Solar has estimated and attempted to quantify a number of externalities that it believes should be included in the Export Credit Rate payments to solar customers. These costs are not explicitly included in RMP rates. These Vote Solar avoided costs are:

- Fuel Price Hedge $1.90/MWh
- CO_2 compliance costs $28.0/MWh
- Health benefits from reduced air pollution $20.9/MWh
- Benefits of reduced CO_2 emissions $65.7/MWh
- Local economic benefits $33.7/MWh

The total amount of these additional Vote Solar avoided costs is $150.2/MWh. All of RMP's cost components are direct costs (fuel, purchased energy, losses, solar integration cost offset) that implicitly customers would otherwise pay in rates, but for the exported solar energy. RMP's position is

consistent with the PSC's Conclusion of Law on Statutory Interpretation and Order Denying Motion to Strike that found that the payments to solar customers for exported energy should reflect the actual costs that are avoided by RMP and its customers through rates.[18] The OCS continues to support this position. Vote Solar's proposal to add an additional $150.2/MWh to the Export Credit Rate, an amount approximately 50% greater than the total current retail residential rate, is not a realistic proposal. RMP's non-participants would pay substantially more for exported solar energy than they otherwise would pay, absent this energy. There is no basis to impose this cost penalty on non-participants and it should be rejected; these costs are not directly quantifiable because they are not included in customer rates. OCS witness Michele Beck addresses these issues in more detail.

Summary

Q. PLEASE SUMMARIZE YOUR CONCLUSIONS.

A. The OCS generally supports RMP's Schedule 137 Export Credit proposal, including real time metering, expiration of credit balances, and seasonal and time-of-day price differentiation. The OCS believes that the PSC should reject Vote Solar's primary recommendation to re-open the NEM Tariff Schedule (Schedule 135) on the grounds that the Tariff contains fundamental deficiencies, which this proceeding is attempting to address. Furthermore, the OCS supports RMP's selection of components to include in its Export Credit Rate calculation including avoided energy costs, avoided energy losses, and integration costs. However, the

[18] PSC Order, Docket No. 14-035-114, July 1, 2015, at pg. 17.

OCS offers two adjustments to RMP's calculation. First, in the case of losses, the OCS recommends the adoption of Vote Solar's line loss proposal, which includes secondary transformer losses. However, the OCS only accepts Vote Solar's line loss proposal on the grounds that it should be applied to a one-year estimate of avoided energy costs. Second, the OCS recommends removal of market caps during day-time hours. Market caps were originally intended to limit coal-fired generation and market energy sales during night-time hours, not during day-time hours when solar resources operate. The combination of the two adjustments results in a small increase in RMP's Export Credit Rate from $15.26/MWh to $17.72/MWh.

Q. DOES THIS COMPLETE YOUR TESTIMONY?

A. Yes, it does.