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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 Phase 2**

REBUTTAL TESTIMONY OF MICHAEL MILLIGAN, PH.D.

ON BEHALF OF

VOTE SOLAR

July 15, 2020

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I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Michael Milligan. My business address is 9584 W 89th Avenue, Westminster, Colorado 80021.

Q. On whose behalf are you submitting this rebuttal testimony?

A. I am submitting this rebuttal testimony on behalf of Vote Solar.

Q. By whom are you employed and in what capacity?

A. I am principal consultant with Milligan Grid Solutions, Inc., an independent power system consulting firm.

Q. Please summarize your educational and professional experience.

A. I have a Ph.D. in Economics from the University of Colorado and a B.A. from Albion College in Mathematics. My experience includes working in the power system industry for about seven years. Then, I was Principal Researcher at the National Renewable Energy Laboratory ("NREL") for 25 years, where I authored/co-authored more than 225 technical reports, journal articles, and book chapters. I served on multiple technical committees at the Western Electricity Coordinating Council ("WECC") and the North American Electric Reliability Corporation ("NERC"), which is the official reliability regulator in the U.S., and I was a charter member of the IEEE Wind and Solar Coordinating Committee. For many years I served on the International Energy Agency Task 25 – Large-scale Wind Integration – research team where I led multiple international research papers on integrating wind into the power system. As an independent consultant, my clients have included NERC, the Electric Power Research Institute, the Southwest Power Pool, GridLab, and multiple trade and educational/research organizations. Exhibit 1-MM to the Revised Affirmative Testimony of Michael Milligan, filed May 8, 2020, provides a statement of my qualifications and experience.

Q. Have you previously testified before the Utah Public Service Commission ("PSC" or "Commission")?

A. Yes. I submitted Affirmative Testimony in Phase 2 of this Docket.

II. PURPOSE OF TESTIMONY

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to provide rebuttal to the Direct Testimony of Rocky Mountain Power ("RMP" or the "Company") witness, Daniel MacNeil, filed on February 3, 2020, and the Direct Testimony of Division of Public Utilities ("DPU") Witness, Robert Davis, filed on March 3, 2020.

III. SUMMARY OF RECOMMENDATIONS

Q. Please provide a brief summary of your recommendations to the Utah Public Service Commission ("PSC") considering the Direct Testimonies of RMP and DPU.

A. I have three recommendations. *First,* the Commission should accept the Vote Solar method for calculating avoided energy costs. The RMP method is flawed, uses historical price curves that do not reflect the state of the future grid, and rests on a model that RMP is likely to retire. *Second*, I recommend that the Commission accept the Vote Solar method for calculating capacity contribution. RMP argues that customer generation ("CG") solar does not supply any capacity benefit to the grid. This is demonstrably incorrect, as my rebuttal testimony will show. *Third*, I recommend that integration costs for CG should *not* be included in the avoided cost calculations for CG solar because it is unduly discriminatory—other resources that impose integration costs are not assessed on the basis of those costs. My rebuttal testimony shows that conventional resources such as gas, coal, or nuclear can impose integration costs. I also show that inverter-based resources, including CG solar, can provide those very grid services for which integration costs purportedly are incurred.

My lack of comments on any components of other parties' direct or affirmative testimony should not be interpreted as acquiescence or agreement. I reserve the right to express additional opinions, to amend or supplement the opinions in this testimony, or to provide additional rationale for these opinions as additional documents are produced and new facts are introduced during discovery and trial. I also reserve the right to express additional opinions in response to any opinions or testimony offered by other parties in this proceeding.

IV. AVOIDED ENERGY COSTS

Q. Please describe avoided energy costs.

A. My Revised Affirmative Testimony dated May 8, 2020 describes how CG energy results in avoided energy costs.[1] For each MWh of CG energy that is produced, RMP reduces its energy delivery requirement to its end-use customers by an equivalent MWh. RMP can then either reduce the output from a generator, or it can sell an extra MWh to one of the trading hubs in the West. I describe these trading hubs in my Revised Affirmative Testimony.[2]

Q. What method is used by RMP to calculate the value of CG solar energy?

A. RMP's primary method for valuing QF energy is the GRID model, which simulates power system operation by calculating an economic dispatch.[3] The simulated dispatch takes into account the many physical constraints on the power system, and using forecast fuel cost and other cost inputs, performs the economic dispatch calculations that are intended to minimize the production cost of the system. GRID serves as the backbone for the Proxy/Partial Displacement Revenue Requirement ("PDDRR") method RMP uses to calculate avoided cost.

Because RMP is part of PacifiCorp, and because PacifiCorp is a charter participant in the Western Energy Imbalance Market ("EIM"), the Company is able to buy and sell energy

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[1] Vote Solar, *Revised Affirmative Testimony of Michael Milligan*, May 8, 2020, at lines 85–181 (hereinafter "*Milligan Revised Affirmative*").
[2] *Milligan Revised Affirmative*, line 229.
[3] RMP, *Direct Testimony of Daniel J. MacNeil*, Feb. 3, 2020, line 64 (hereinafter "*MacNeil Direct*").

via this market at prices that are established in real-time by system conditions. These conditions primarily include the so-called "dispatch stack," which represents the set of generator and other resources' dispatch settings. The EIM "enables participants anywhere in the West to buy and sell energy when needed."[4] This means that, as a participant in the EIM, RMP can buy or sell a MWh through the EIM at the prevailing price, which is determined every five minutes at the EIM market nodes. PacifiCorp has saved $243 million since entering the EIM in 2014.[5] RMP witness MacNeil describes how historical EIM prices were used as part of the evaluation of avoided energy cost of CG.[6] I address this use of EIM prices in RMP's method later in my Rebuttal Testimony.

Q. What is your assessment of the RMP method to calculate the avoided energy cost of CG solar energy?

A. I have several concerns. These concerns fall into two categories: (1) shortcomings of the GRID model and (2) applying an inappropriate pricing vector to the GRID results.

Q. Please explain your concerns regarding shortcomings of the GRID model.

A. I have four areas of concern with the GRID model. *First*, the GRID model does not possess sufficient granularity to properly calculate the energy value of CG solar energy. *Second,* the GRID model "bakes in" Integrated Resource Plan ("IRP") resources, altering the avoided energy cost for CG. *Third,* some gas plants are committed in the model and are locked into that commitment schedule even if there is a change to solar energy. *Fourth,*

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[4] *Western Energy Imbalance Market*, available at https://www.westerneim.com/pages/default.aspx (last visited May 7, 2020).
[5] *Id.*
[6] *MacNeil Direct*, line 87.

some outputs of the GRID model are modified by RMP "to accurately represent avoided cost."[7] This means there is some subjectivity in the analysis and also a loss in transparency.

Q. Please explain your concern regarding the lack of granularity of the GRID model.

A. RMP Witness MacNeil describes in detail how the GRID model is used to calculate the company's avoided cost from new QF resources.[8] GRID implements the PDDRR method to calculate avoided cost, and this method is then applied to valuing CG exports. However, Mr. MacNeil concedes that the GRID model results are not sufficiently granular to determine an export credit.[9] To correct for GRID's lack of sufficient granularity, RMP used a "shaping" algorithm that applied normalized prices from the EIM to the GRID output. EIM prices, on a 15-minute time step from the 36-month period ending in October 2019, are utilized in this process. In using EIM prices this way, RMP's method is similar in concept to the Vote Solar approach, which also utilizes market prices to value the energy avoided cost that results from CG solar. Using market prices to shape the value of CG solar—which both RMP and Vote Solar do—is sound in principle. However, RMP uses historical prices that are unlikely to represent future pricing, whereas Vote Solar uses future Official Forward Price Curve ("OFPC") prices, described in more detail below. The OFPC is developed to account for the anticipated future changes in the grid, along with their impact on wholesale electricity prices. I discuss this issue further below.

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[7] Exhibit 1-MM, *Response to Vote Solar Data Request 12.2(4)*, RMP's Responses to Vote Solar 12th Set of Data Requests (May 15, 2020).
[8] *MacNeil Direct*, lines 46–260.
[9] *Id.* at lines 79–84.

Q. Please explain what it means to "bake in" resources, and explain your concern as it related to the GRID model.

A. The GRID model has IRP resources "baked in." This means that RMP is assuming all IRP resources, including those that are anticipated but not yet built, will be developed and deployed ahead of existing CG. The order in which resources, regardless of ownership, are added to any production cost model will determine the incremental value of each resource. Existing resources, including CG solar, should take precedence over IRP resources that may not be developed in later years. Each time a resource is added into a dispatch model such as the GRID model, the supply curve of the utility changes. If a solar or wind IRP resource is modeled, but not built, its presence in the model will reduce the value of CG solar. This is a direct consequence of the impact that wind or solar resources have on the supply curve.[10] Baking in one or more resources will result in an incorrect valuation of CG solar because the addition of any new resource will have declining marginal value as more resources are added because of the way resources are dispatched. If potential future IRP resources displace CG solar in the model, then CG avoided energy costs will be incorrect. A rate calculated using these incorrect avoided energy costs will in turn send incorrect price signals to potential CG solar customers. This distorted price signal will have an impact on the economics of installing CG solar resources.

[10] This issue is known as the "merit order" effect. *See* Bethany A. Frew, Michael Milligan, Greg Brinkman, Aaron Bloom, Kara Clark, & Paul Denholm, *Revenue Sufficiency and Reliability in a Zero Marginal Cost Future*, Nat'l Renewable Energy Lab. (2016), https://www.nrel.gov/docs/fy17osti/66935.pdf.

Q. Please explain what it means to "lock in place" natural gas resources in the GRID model, and explain why this is a concern.

A. RMP states that the commitment of some natural gas plants in the GRID model is "locked in place" to reduce the potential for "disproportionate variances."[11] This means that the economic dispatch algorithm in the GRID model is overridden by manual input. When this occurs, the gas plants in question will not change their output no matter the quantity of CG generation. This effectively turns off the economic optimization that is a vital part of dispatch models such as GRID. Although there may be cases in which gas plant commitment should not change with the addition or subtraction of small resources, this introduces an element of subjectivity and is not a transparent use of the model. When units are locked in, the model is unable to fully optimize the resulting commitment and dispatch, which raises questions about the validity of the results.

In a robust modeling framework, the determination of which plants should be locked in place would require multiple model runs, identifying infeasible or impractical solutions. The decision of whether to lock in some gas plants is not transparent, and the fact that RMP believes that some plants should in fact be locked in indicates a shortcoming of the model because it is unable to provide consistent, plausible commitment and dispatch.

[11] Exhibit 1-MM, *Response to Vote Solar Data Request 12.2(3)*, RMP's Responses to Vote Solar 12th Set of Data Requests (May 15, 2020).

Q. Please explain your concern regarding the modification of GRID outputs to better reflect avoided cost.

A. Because RMP manually adjusts the outputs of the GRID model, there is no transparency in how avoided costs are calculated, and it is impossible to verify whether the results are accurate. RMP states that some outputs from GRID are modified to "accurately represent avoided cost."[12] These adjustments result from GRID's inability to utilize dispatch costs of zero or less than zero $/MWh.[13] Negative dispatch costs may occur because of production tax credits for which renewable sources may qualify. Additionally, RMP states that "avoided cost results reflect incremental coal costs, while GRID reports a point estimate of average costs, (i.e., based on a single pre-determined volume)."[14] The spreadsheet outputs from the GRID model make adjustments to allow for both of these; however, negative dispatch costs, and even negative prices (should they occur), are an important part of efficient economic dispatch and should be calculated within the dispatch model.[15]

Q. Does RMP apply energy prices to the output of the GRID model?

A. Yes. RMP uses 15-minute prices from the EIM for the 36 months ending October 2019, taken from one of the PacifiCorp East ("PACE") load aggregation points ("LAP").[16]

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[12] Exhibit 1-MM, *Response to Vote Solar Data Request 12.2(4)*, RMP's Responses to Vote Solar 12th Set of Data Requests (May 15, 2020).
[13] *Id*.
[14] *Id*.
[15] For a discussion of the economic efficiency of negative pricing/dispatch cost, see *Negative Pricing in Wholesale Energy Markets*, the Brattle Group, Nov. 30, 2018, available at https://www.brattle.com/news-and-knowledge/publications/archive/2018.
[16] *MacNeil Direct*, line 86.

Q. Why is it inappropriate to apply this EIM pricing vector to the GRID results?

A. The use of historical prices in the adjustment of the GRID model outputs is not appropriate because it bears little relationship to future prices on which the avoided energy cost is based and will result in incorrect estimates of avoided energy cost in this proceeding. The implication of RMP's approach is that the relative prices from the EIM do not capture the changing nature of the power system, as large coal units are retired and deployment of new renewable and storage facilities increase. This is important because wholesale electricity prices are determined by the intersection of the supply and demand curve for electricity at each dispatch interval. The supply curve is constructed from all the individual resource characteristics, primarily from the marginal cost of each resource over its potential operating range. This means that using prices that were established by historical resources will result in different—perhaps vastly different—prices than those established by the changing and future resource mix. The use of an incorrect pricing vector results in invalid estimates of the cost of avoided energy. CG customers will be evaluating long-term rates, and the export tariff should be developed accounting for the best possible information about the future, not the past. While I agree with RMP that wholesale electricity prices are appropriate for valuing the avoided energy cost of CG, using the historical EIM data results in invalid results.

Q. How could an acceptable price vector be developed?

A. An electricity production simulation model of the Western Interconnection that includes detailed information about the RMP system could be used to calculate a valid price stream. Such a model should represent the changing resource mix, which is important to develop accurate estimates of avoided energy value. Future prices on an hourly level (or less) and at relevant trading hubs accessible to the PACE balancing area, taking into account the *best possible information* regarding future system conditions, will provide a more accurate view of the future.

Q. Is there a model that RMP could rely on to develop more accurate estimates of avoided energy value?

A. Yes. One highly regarded model that could provide better market estimates is AURORA$_{XMP}$ ("Aurora"). Aurora can be set up to represent the entire Western grid, with the best-available information about future resources and transmission changes.

Q. Do you have any evidence that the Aurora model can provide reliable estimates of future electricity prices?

A. Yes. PacifiCorp states in its 2019 IRP that it has used Aurora to produce its OFPC. According to RMP, "[t]he Company's long-standing methodology to develop its [OFPC] produces the *best representation of future market prices and is appropriately used for the central forecast in the Company's economic analysis*."[17]

Because the OFPC is forward-looking, it accounts for the changing resource mix in the future along with changes in the transmission network—in contrast to MacNeil's EIM data, which is historical and cannot capture the future nature of the grid or future electricity prices.

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[17] RMP, *Rebuttal Testimony of Rick T. Link*, Idaho Public Utilities Commission, Docket No. PAC-E-17-07, at 2, Dec. 18, 2017, https://www.rockymountainpower.net/content/dam/pcorp/documents/en/rockymountainpower/rates-regulation/idaho/filings/case_no_pac_e_17_07/12-18-17_rebuttal_testimony/06_Rebuttal_Testimony_Rick_Link.pdf (hereinafter "*Link Rebuttal*") (emphasis added).

Q. Please explain how the OFPC was developed.

A. The OFPC was developed by PacifiCorp. According to RMP's Response to Vote Solar Data Request 12.3,[18] the following are used in the development of the OFPC:

1. Natural gas price forecast(s) supplied by expert third-party forecasting services;
2. PacifiCorp's macro-economic forecast of inflation for converting real-dollar assumptions to nominal dollars;
3. Data regarding new units added to, and retired plants removed from, WECC, which is sourced from the United States Energy Information Administration ("EIA"), and S&P Global;
4. Renewable builds, as required by states' renewable portfolio standards sourced from an expert third party's forecast;
5. Transmission links, emission rates, and WECC loads sourced from Energy Exemplar, the developer of Aurora;
6. Reserve margins, natural gas pipeline tariffs, and generic technology cost updates sourced from Energy Exemplar and online tariff sheets; and
7. Hourly scalars are applied to the monthly OFPC to convert monthly values to hourly values.

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[18] Exhibit 1-MM, *Response to Vote Solar Data Request 12.3(1)*, RMP's Responses to Vote Solar 12th Set of Data Requests (May 15, 2020).

Q. Does the OFPC account for the changing resource mix in the future for RMP and neighboring systems?

A. Yes. Plant additions and retirements in the Western Interconnection were accounted for in the development of the OFPC. This is critical because the mix of resources will drive the market price, along with fuel prices, which are included in No. 1 above. This resource mix also includes No. 4, renewable resource additions, which also have a key impact on energy prices. Future transmission links (No. 5 above) alter the economic dispatch of units in the region and therefore play a key role in energy value. In short, the items used to create the OFPC take into account forecasted future developments in the interconnection, whereas historical EIM prices do not account for any of these changes.

Q. The OFPC represents electricity prices between RMP and neighboring utilities/power systems. How is this relevant for determining the avoided energy value of CG solar?

A. PacifiCorp's 2019 IRP points out the importance of market interaction with neighboring systems: "PacifiCorp's system does not operate in an isolated market. Operations and costs are tied to a larger electric system known as the Western Interconnection which functions, on a day-to-day basis, as a geographically dispersed marketplace. Each month, millions of megawatt-hours of energy are traded in the wholesale electricity market. These transactions yield economic efficiency by assuring that resources with the lowest operating cost are serving demand in a region and by providing reliability benefits that arise from a larger portfolio of resources."[19] In using the EIM prices, RMP itself implicitly agrees that wholesale prices are an appropriate way to value CG energy.

Q. Do you have other evidence that the GRID model with historical EIM data is not a sufficient valuation approach?

A. Yes. According to RMP,[20] the GRID model will be discontinued and replaced by a model that can perform nodal pricing.[21] PacifiCorp is currently testing Aurora and Plexos, both of which can perform nodal pricing. RMP's intent to abandon the GRID model shows that it has a lack of confidence in the GRID model, and more confidence in other models, including Aurora, which is the model that was used by PacifiCorp to determine the OFPC in its 2019 IRP. Thus, RMP is moving away from the GRID model and towards a method and modeling framework that is consistent with the Vote Solar approach, as further explained below.

As stated above, RMP agrees that its "long-standing methodology to develop [the OFPC] produces the best representation of future market prices and is appropriately used for the central forecast in the Company's economic analysis."[22] This same OFPC—that RMP concedes is the best representation of future marketing prices—is not used by RMP in this

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[19] *2019 Integrated Resources Plan*, PacifiCorp, p. 36, Oct. 2019, https://www.pacificorp.com/energy/integrated-resource-plan.html.
[20] Exhibit 1-MM, *Response to Vote Solar Data Request 12.1(1), 12.1(3)*, RMP's Responses to Vote Solar 12th Set of Data Requests (May 15, 2020).
[21] Nodal pricing is preferred to the zonal pricing alternative because it can better resolve congestion and results in more accurate pricing. *See* Hytowitz, et. al, *Impacts of Price Formation Efforts Considering High Renewable Penetration Levels and System Resource Adequacy Targets*, Nat'l Renewable Energy Lab. (2020), https://www.nrel.gov/docs/fy20osti/74230.pdf.
[22] *Link Rebuttal*, Idaho Public Utilities Commission, Docket No. PAC-E-17-07 at 2.

proceeding but is used by Vote Solar to calculate the avoided energy cost of CG. Specifically, the Vote Solar method utilizes the OFPC that was developed by PacifiCorp for each hour from 2021-2040 and for each of the relevant trading hubs. It is forward-looking, in contrast to MacNeil's EIM data, which is historical. This is why it is most appropriate to use the best possible wholesale electricity price information to determine the value of CG energy and why it is important to utilize prices for trading hubs to which PacifiCorp/RMP have access. This is precisely what Vote Solar has done and what RMP has failed to do. In spite of RMP's claim that the OFPC is the best forecast for future market prices and that the OFPC should be used for the Company's economic analysis, RMP has not justified why it has ignored the OFPC in this proceeding.

Q. Are forecasts inherently inaccurate?

A. Forecasts such as these are subject to forecast error. The role of variable renewable energy development, coal retirements, and the evolution of demand into the future cannot be known with certainty. However, it *is* certain that historical EIM prices do not accurately represent future prices because we know that many factors are changing, and these changes will have significant influence on energy prices. We also know that the resource mix is likely to change in most years; therefore, it is not reasonable to utilize a static set of prices, or price shapes, for the future. In another proceeding, RMP stated that "all long-term resource planning requires the use of long-term assumptions and forecasts."[23] Even though reality may evolve differently than expected, given the ongoing changes in the resource

[23] *Id.* at 12 (emphasis added).

mix, we know with certainty that the future will not replicate the past. Therefore, the best possible future information is preferable to a simple extrapolation from the past.

Q. Are there any improvements that could be made to the OFPC?

A. Yes. The OFPC could be improved by incorporating the best-available information regarding the EIM. According to RMP's Discovery Response to Vote Solar 12.3,[24] the EIM is not accounted for in the development of the OFPC. This does not diminish the fact that the OFPC is the best available assessment of wholesale electricity prices in the region in the years covered by PacifiCorp's IRP, but it does diminish its accuracy relative to a version of the OFPC that would have included the EIM. Future OFPC estimates would benefit from inclusion of the EIM, including some assessment of the range of EIM prices under different EIM membership assumptions, as described below. RMP is in the position to create such a future version, which would be based on the Company's internally-developed forecasts for inputs to the Aurora model.

For example, membership in the EIM is expected to change during the next few years.[25] Changing membership will also change the EIM supply curve, which will change EIM prices. In addition to changing membership, the California Independent System Operator ("CAISO"), which operates the EIM, currently has an initiative that would extend the real-time EIM so that it also includes a day-ahead market ("EDAM," or extended day ahead

[24] Exhibit 1-MM, *Response to Vote Solar Data Request 12.3(2)*, RMP's Responses to Vote Solar 12th Set of Data Requests (May 15, 2020).
[25] *See Western Energy Imbalance Market*, available at https://www.westerneim.com/pages/default.aspx (last visited May 7, 2020).

market). This is expected to go online in the next couple of years, which will also have a significant impact on the supply stack and, therefore, on electricity prices.[26]

Q. In his Direct Testimony, Robert Davis[27] used EIM prices from February 10, 2020 to show that RMP's avoided cost is "reasonable." Do you agree with that assessment?

A. No. It is not clear why this day was chosen. Any such choice would need accompanying evidence as to why it accurately represents prices over the year. Such evidence was not presented. The following graph shows confidential OFPC prices from February 10, 2020. [redacted] Therefore, one cannot conclude that a price strip from February 10 is representative of the full year.

[26] *See INITIATIVE: Extended day-ahead market*, California ISO, available at http://www.caiso.com/StakeholderProcesses/Extended-day-ahead-market.
[27] DPU, *Direct Testimony of Robert A. Davis*, Mar. 3, 2020, line 56 (hereinafter "*Davis Direct*").

[redacted]

Figure 1. Price comparison for February 10, 2020

Q. Do you have any further concerns regarding the avoided energy cost for CG solar?

A. Yes. I recommend that the Commission dis-allow the deduction that RMP made for integration costs.[28] I address this in the next section of my Rebuttal Testimony.

Q. Can you summarize your Rebuttal Testimony above regarding avoided energy cost?

A. The RMP calculation of avoided energy cost for CG solar is based on GRID model output, which is adjusted to historical price information and fails to account for future resource changes. The GRID model is a black box model, as it is not transparent. It has several deficiencies as outlined above, and as a result, RMP intends to retire the GRID model and implement a better nodal model—potentially, Aurora. Aurora is already used

[28] *MacNeil Direct*, line 54.

by PacifiCorp to develop its OFPC, which the Company has stated—on record—is the best available representation of future prices. The Vote Solar approach relies on the OFPC and therefore overcomes these weaknesses and provides a more accurate assessment of the avoided energy cost for CG solar.

V. INTEGRATION COSTS

Q. Do you have any other concerns about how RMP calculated the avoided energy cost of CG solar?

A. Yes. RMP includes a deduction from CG avoided cost that is based on calculated integration costs of CG solar. According to the Direct Testimony of RMP witness Daniel MacNeil, "[i]ntegration costs represent the cost of holding reserves with flexible resources to reliably maintain the load and resource balance."[29]

Q. Why is this a concern?

A. As discussed below, including integration costs for one type of resource based on its type (solar, in this case) is discriminatory and violates a principle of good rate design because it does not recognize other resource types.

Q. What is an integration cost?

A. The definition of "integration cost" is not standard, but it is generally considered to be a cost imposed on one generator, or a group of generators, that is caused by another generator. Integration costs often address an increase in some grid services that is induced

[29] *Id.* at lines 57–58.

by the resource in question.[30] A typical example in the renewable integration literature is automatic generation control ("AGC"): if wind or solar energy impose additional regulation requirements on a given power system, then the argument is that they should somehow pay for that service.[31] In addition to regulation, other grid services are sometimes addressed in integration cost calculations. In sum, renewable integration costs are described as costs the grid operator incurs to obtain additional grid services so that the resource can be integrated into the power system. As I show below, non-renewable resources can also have an integration cost; however, this is rarely, if ever, assessed.

Q. Did Vote Solar include an integration cost in its avoided energy cost calculation?

A. In the Vote Solar analysis, integration costs were not included because: (1) they are unduly discriminatory; (2) there exists no broadly accepted way to calculate integration costs, thus rendering it a subjective calculation; and (3) smart inverters such as those used in photovoltaic ("PV") installations can provide many of the grid services that are included in integration cost assessments if appropriate market or contractual signals are put in place (which is especially important at higher solar penetrations).[32]

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[30] Grid services generally consist of frequency regulation, voltage support, and other balancing services that are required to ensure grid reliability.

[31] Regulation is the short-term change in net demand and is typically supplied by generators on automatic generation control. Renewable resources generally increase the regulation requirement of the grid but can also supply regulation.

[32] Michael Milligan, *Sources of grid reliability services*, 31 The Elec. J. 1 (2018).

Q. Why are integration costs for solar energy unduly discriminatory?

A. Integration costs for renewable energy sources are unduly discriminatory because they are not performance-based[33] and are not calculated for all resources—only renewables. In cases where other, non-renewable resources incur integration costs, these are rarely, if ever, measured and calculated. Singling out a subset of technologies for which integration costs are calculated is discriminatory and does not keep with performance-based compensation and power market design principles. Recent work at the National Renewable Energy Laboratory[34] has shown that wind and solar are not the only source of integration costs. Other examples of resources or scheduling practices that cause integration costs include: (1) units that set the contingency reserve level; (2) block (hourly) schedules; (3) resources that have difficulty accurately following AGC signals; (4) resources that have difficulty maintaining output level as directed by a setpoint instruction; and (5) resources that are inflexible with some combination of limited ramp or turn-down capability. Solar and wind are not the only resources that create integration costs, but they are the only resources for which RMP assesses the costs of integration. That is discriminatory.

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[33] A performance-based assessment is generally agnostic as to the type of resource and instead focuses on the resource's level of consumption or provision of grid services.

[34] Michael Milligan, et al., *Integration of Variable Generation, Cost-Causation, and Integration Costs*, 24 The Elec. J. 51 (2011); Greg Stark, A *Systematic Approach to Better Understanding Integration Costs* (2015), https://www.nrel.gov/docs/fy15osti/64502.pdf (showing that even though thermal cycling costs may increase with increasing renewables, variable O&M costs decline further). Overall operational cost declines in all cases when renewables are added to the system in this analysis.

Q. Do conventional resources also impose integration costs?

A. Yes. Below at line 409, I show one example of a thermal resource that increases the need for regulation and another that shows the impact of a conventional resource on ramping and cycling of other resources. Below at line 471, I will also discuss how wind and solar, through their smart inverters, can provide the grid services for which they are assessed integration costs.

Q. What did PacifiCorp assume about conventional resources in its integration cost assessment?

A. In its 2019 IRP,[35] PacifiCorp assumes that all conventional resources follow signals perfectly and thus all the integration cost burden falls on variable energy resources ("VER") such as wind and solar energy. There are at least two flaws that overstate the increase in flexibility reserve burden on VER: (1) not all conventional units can accurately follow dispatch or regulation instructions and (2) wind and solar generation are often capable of providing frequency regulation and dispatch services,[36] although bi-directional dispatch and regulation can be provided only if the resource is "pre-dispatched" below its maximum generation. Utilizing this capability could eliminate any integration cost from a VER. Currently, distribution-connected resources do not always have the communication and control capabilities to provide these services, but they will be required to have a combination of communication and control capability once new requirements for

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[35] *2019 Integrated Resources Plan*, PacifiCorp, Volume I, Chapter 6, Table 6.2 pp. 140–43, Oct. 2019, https://www.pacificorp.com/energy/integrated-resource-plan.html.
[36] *See* Debbie Lew & Nick Miller, *Short-term reliability: System Stability Part 1*, W. Energy Bd. (Apr. 29, 2020), https://westernenergyboard.org/wp-content/uploads/2020/04/04-29-2020-WIRAB-series-Webinar3-Short-Term-Reliability-System-Stability-Part-1.pdf.

distributed resources, known as the IEEE 1547-2018 standard, has been implemented.[37] With this new standard, voltage and frequency ride-through, and voltage and frequency regulation, will be available from CG solar. This means that distributed resources can respond to certain grid conditions, providing many grid services and helping to support grid frequency and balance, and power quality will be increased for all customers. RMP's assumption that all integration costs fall on VER resources is therefore inaccurate, and so it is inappropriate to include integration costs only for CG solar.

Given that states will have the ability to tailor distributed solar performance characteristics, in line with the new IEEE 1547-2018 standard, it would appear appropriate for the Commission to consider opening a Docket to establish how new interconnection standards would best be implemented for new solar resources, maximizing the value to consumers.

Q. Why is PacifiCorp's assumption that conventional resources can accurately follow regulation and dispatch signals incorrect?

A. Not all resources perform in the same way. A full integration cost analysis should also assess the potential for *any* resource to increase system regulation requirements, based on that's plant's performance. I have included an example analysis of a generator that imposed a regulation burden on the Midcontinent Independent System Operator ("MISO").[38] The example uses data from two similar coal plants. The first of these two plants, shown at the top half in Figure 2, is capable of following a regulation AGC signal

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[37] Bryan Lydic, *Smart Inverter Update: New IEEE 1547 Standards and State Implementation Efforts*, Interstate Renewable Energy Council (July 23, 2018), https://irecusa.org/2018/07/smart-inverter-update-new-ieee-1547-standards-and-state-implementation-efforts/.
[38] *See supra* note 34.

with reasonably high accuracy. Using data from the MISO Power Information ("PI") database, the first unit receives an AGC signal represented by the dotted green line with the unit's response shown as a solid red trace. As demonstrated, the unit sufficiently follows the AGC signal with a slight lag.

The second unit in this example, shown in the bottom half of Figure 2, is unable to accurately follow the AGC signal and help the system operator maintain nominal frequency. On the contrary, this second plant causes an *increase* in the need for regulation services, reaching 31 MW. Accordingly, this second unit imposed an integration cost because it increased the regulation requirement by 31 MW in this time period.

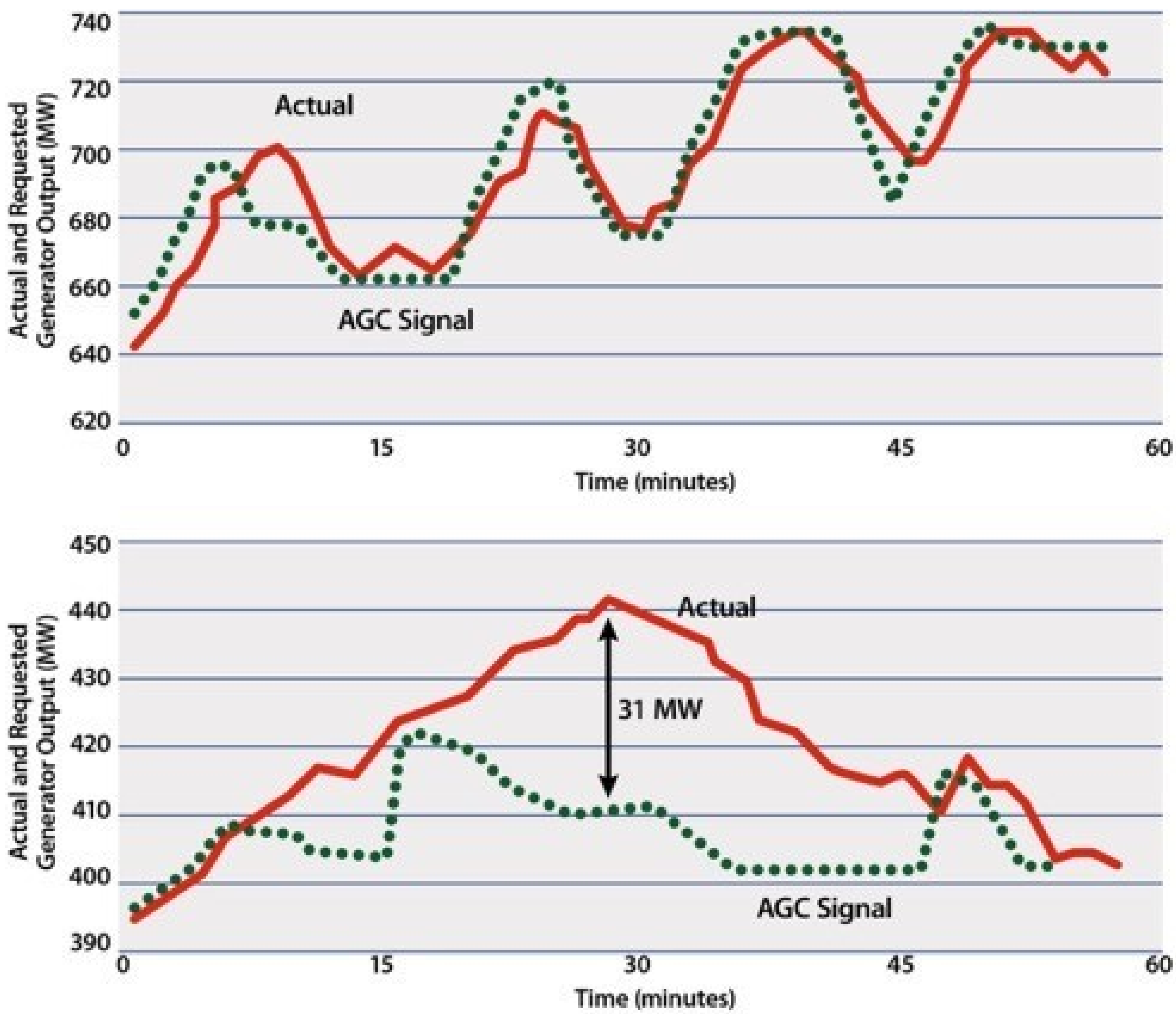

Figure 2. Example of a thermal plant imposing an integration cost on the MISO system

This example shows that it is possible for thermal plants to impose a regulation burden, which would be considered an integration cost to the system. If a performance-based, non-discriminatory tariff had been in place, the plant in the upper panel of the diagram would have no (or very low) integration costs, whereas the lower one would have relatively high integration costs.

However, conventional plants are rarely, if ever, assessed integration costs even though they may consume regulation services. On the other hand, wind and solar generation are often assessed integration costs based on regulation services. This is fundamentally discriminatory.

Q. Are there other types of integration costs that are often assigned to renewable resources that are not recognized with conventional resources?

A. Yes. The addition of renewable resources can induce an increase in ramping requirements for the other resources on the system. Ramping of a resource means that it is changing its output level. In some cases, resources that are needed online less often incur more starts and stops. During these changes in output, thermal units often operate less efficiently, burning more fuel per kWh than if they were run in a steady state. The resulting costs are sometimes collectively referred to as "cycling costs." Cycling costs can be incurred when a new conventional resource is added to the system. I provide an example below.

Q. Please explain how the addition of a new conventional resource causes integration costs that are related to ramping or cycling.

A. Cycling costs can be caused by the addition of a base-load plant to the system. In addition to the cycling costs, the affected plant's capacity factor is reduced because the new addition to the resource mix has a lower marginal cost.

To illustrate, I focus on a graphical depiction in Figure 3.[39] The upper panel shows a "typical" simple power system consisting of coal generation, natural gas combined-cycle

[39] *See supra* note 34. As indicated in the technical paper, the impacts of wind and solar are qualitatively the same but differ relative to timing and level of variability and uncertainty.

plants, and combustion turbines. (Note that the specific technology type is not relevant for this analysis, only that one type of unit at the bottom of the dispatch stack begins by providing constant power for the week.) A wind plant is added to the system, as depicted in the middle panel. Because the marginal cost of wind (and solar) energy is essentially $0/MWh, the wind is dispatched prior to coal. In this case, the coal plant's capacity factor declines, and it must cycle on Wednesday, Thursday, and Saturday. The coal plant loses some revenue if it is in a market, and it incurs some operational cost as its cycling increases.

The bottom panel of Figure 3 uses the upper panel of the figure as its starting point. A new base-load unit is added into the simple system in the top panel, instead of adding wind generation. For this example, the new base-load generation has a lower dispatch cost than the coal plant, and it is therefore chosen in the economic optimization to have priority over the coal plant. This moves the coal plant "up" the dispatch stack, where it cycles every day and has a reduced capacity factor for the week. The results of this example are quantitatively different than in the wind case, but the impact is the same qualitatively—whether a wind plant or a new, cheap baseload plant is added to this system, the coal plant loses energy sales and has an increased cost of cycling. This means that the baseload plant imposes a cycling cost, which is sometimes assessed as an integration cost.

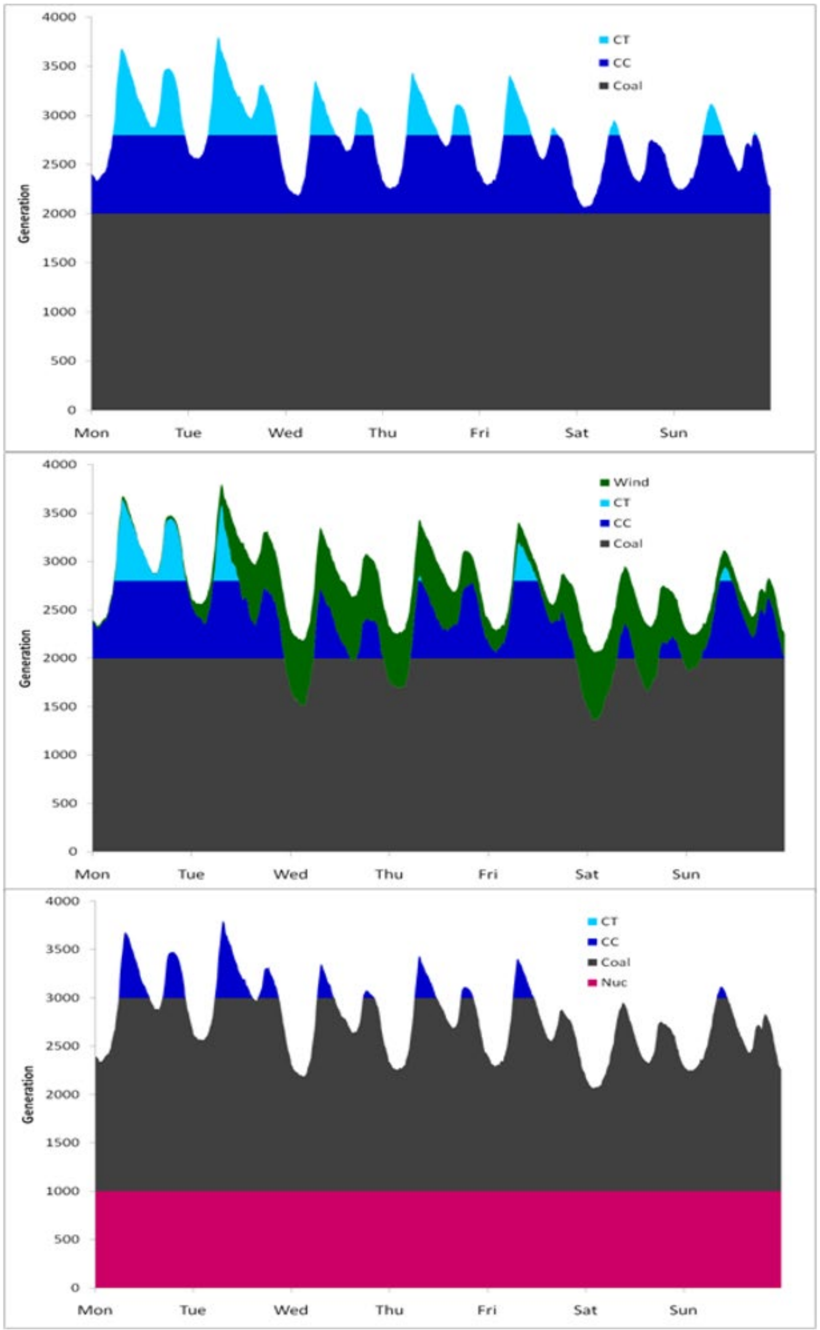

Figure 3. Integration cost for different resources

Q. Can wind and solar provide grid services?

A. Yes. The technology embedded in wind and solar plants, as well as distributed inverters, can now provide many grid services to offset the integration impacts and potential costs for which RMP proposes to charge CG customers. As I testified above, the new IEEE standard requires grid services from distributed resources; therefore, a forward-looking avoided-cost calculation should account for this offset.[40] I show an example of a wind power plant that provides both AGC, which is a frequency regulation service, and dispatch services.[41] The example is from Xcel Colorado. Figure 4 shows a time period of approximately 4 hours, during which the wind plant provided a combination of dispatch services and AGC. The purpose of this example is to demonstrate that renewable resources can provide some of the grid services—most notably AGC—on which RMP assesses an integration cost. This shows that a performance-based integration cost analysis would conclude that renewable resources, like CG solar, provide grid services rather than consume them. Resources that provide grid services should be paid for them, not charged for them.

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[40] 1547-2018 IEEE Standard for Interconnection and Interoperability of Distributed Energy Resources with Associated Electric Power Systems Interfaces, https://standards.ieee.org/standard/1547-2018.html.

[41] Michael Milligan, et al., *Alternatives No More: Wind and Solar Power are Mainstays of a Clean, Reliable, Affordable Grid*, IEEE Power and Energy Magazine, Nov./Dec. 2015, at 1.

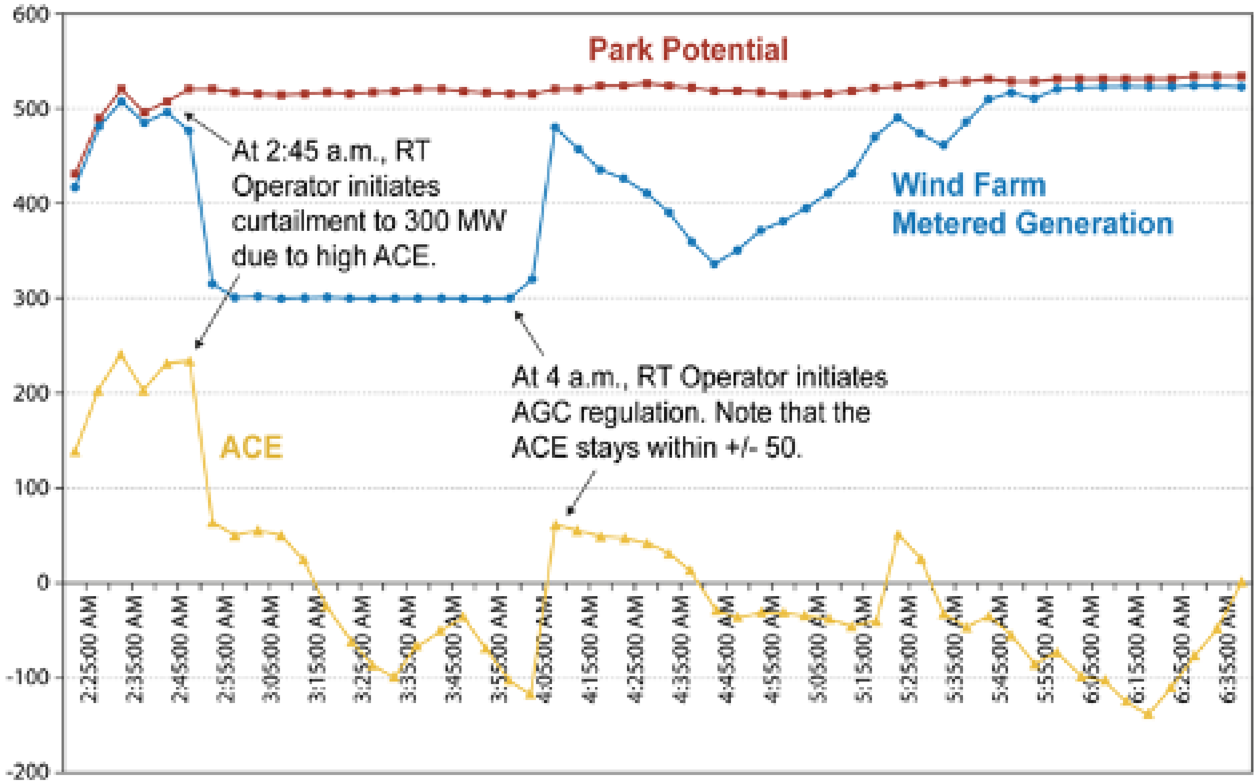

Figure 4. Example of wind plant providing AGC and dispatch services

Q. How is imbalance represented on the graph in Figure 4?

A. The yellow trace, area control error ("ACE"), is a measure of system imbalance. An ACE value of 0 indicates the system is perfectly balanced; the sum of demand and exports is equal to the sum of generation and imports. There is an additional frequency term that is not important for this discussion.[42] A large value of ACE indicates that the system is out of balance; the system either has too much generation and not enough demand, or it has too much demand and not enough generation. A positive ACE indicates that the system is experiencing over-generation relative to demand and should reduce

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[42] *See Balancing and Frequency Control*, North American Elec. Reliability Corp. (2011), https://www.nerc.com/docs/oc/rs/NERC%20Balancing%20and%20Frequency%20Control%20040520111.pdf (showing full equation for ACE).

generation (or increase demand, such as charging a storage device if possible), whereas a negative ACE indicates insufficient generation within the balancing area, indicating that the system should increase generation to maintain system balance.

Q. Please show where on Figure 4 the wind plant responds to dispatch instructions.

A. In Figure 4, starting at about 2:30 AM, the system operator observes that ACE is too high—about 200-250 MW. That means generation should be decreased. In this case, the utility had already turned down all its thermal resources to minimum generation levels. Reducing them further would have required at least one unit to be shut down; however, all the online units would have been unavailable for the next day because of minimum down-time constraints. Therefore, the operator knew that none of the thermal plants could be turned down or turned off. Instead, at 2:45 AM, the operator gave the wind plant a dispatch setpoint that instructed the plant to reduce its output from about 500 MW to about 300 MW. Wind plants (and solar plants, both of which are connected to the grid via power electronics controls) can respond quickly to such commands, as can be seen in Figure 4. ACE falls to less than 100 MW from more than 200 MW very quickly, and it continues to decline until falling below zero. At around 4:00 AM, the operator determined that ACE was too low, and generation should be increased. Instead of instituting a series of manual dispatch commands, the operator changed the control paradigm of the wind plant, putting it on AGC.

Q. Please explain the section of the graph that shows the AGC response.

A. At about 4:00 AM, the wind plant was put on AGC. This means that every 4 seconds, the wind plant would receive a control signal from the AGC that would instruct the plant to increase or decrease output to maintain ACE within limits. At the time of this event, the acceptable limit for ACE was approximately 50 MW. Starting at 4:00 AM, the wind plant output changed so that ACE generally stayed within limits until the morning load pickup began around 6:00 AM.

Q. Are there other grid services that can be provided by renewable sources and smart inverters?

A. Yes. A recent paper I published shows a table of grid services and their possible sources, a portion of which is reflected in Figure 5 below.[43] As demonstrated below, inverter-based resources, which include wind and solar energy, can provide all grid services.

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[43] Michael Milligan, *Sources of grid reliability services*, 31 The Elec. J. 1 (2018).

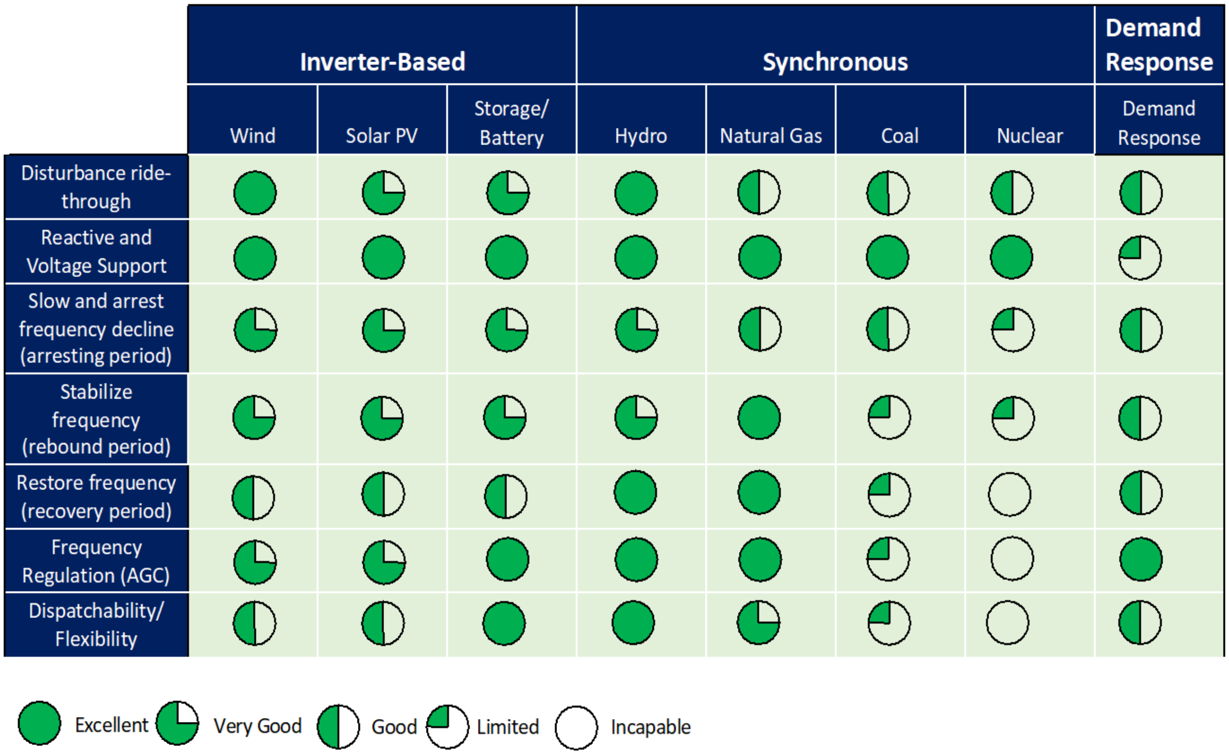

Figure 5. Grid services and sources

Q. Can you summarize your rebuttal testimony above on integration costs?

A. Any resource can potentially impose integration costs on the power system, but renewables are often singled out. If renewable plants' integration costs are calculated and somehow imputed into their net worth, while non-renewable plants are not assessed, the cost burden is unfairly shifted entirely to renewables. Singling out certain technologies for integration cost assessment is unduly discriminatory. It is likely that non-renewable integration costs may, in some cases, exceed that of renewables. Yet there is no generally accepted method or methods for calculating integration costs, rendering the analysis subjective. I recommend that renewable integration costs not be used in regulatory proceedings unless: (1) a rigorous, peer-reviewed, well-established method can be developed, and (2) the same metric is applied to all resources in a non-discriminatory fashion. I also recommend that RMP deploy the ability of renewable energy resources to provide grid services as part of its economic grid operations.

VI. AVOIDED GENERATION CAPACITY COSTS

Q. What is your understanding of RMP's argument that CG solar has no capacity value?

A. According to the Direct Testimony of Daniel MacNeil, "[t]he proposed export credit program is secondary to a customer's own use so it is considered non-firm and no future capacity resources would be deferred."[44]

My understanding of RMP's argument is that because CG solar customers do not have credit terms, security deposits, and other business arrangements that large-scale resources would have with RMP, there is no contractual arrangement that entitles RMP to the capacity available from CG solar. According to RMP, the non-firm nature of CG solar therefore disqualifies it from having any capacity value.

Q. Do you agree with RMP's argument that CG solar customers should not be credited for capacity?

A. No. I disagree with RMP for three reasons. *First*, CG customers are captive consumer/producers, and they cannot sell their excess solar power in any other market or to any other utility. *Second*, CG solar is an as-available resource and may have capacity value that should be calculated, not ruled out *a priori*. *Third*, the notion of "firm" or "non-

[44] *MacNeil Direct*, lines 66–68.

firm" is a binary market distinction. It ignores the probability associated with a resource being online during a period of risk. As described more fully below, the mathematics of risk can incorporate this probability into the resource adequacy calculations.

Q. Why is it relevant that CG customers are captive?

A. CG customers are captive consumer/producers, and they cannot sell their excess solar power in any other market or to any other utility. This market structure is known as a monopsony and has similar market distortions as a monopoly structure, although in the case of monopsony, the buyer (i.e., RMP) has market power and the seller does not. Although it is true that the exported solar energy is a residual after accounting for customer demand, the exported solar is "as-available" energy, and it is therefore similar to other solar and wind energy sources. RMP already creates load forecasts, and solar forecasts could be available so that RMP can forecast the amount of CG generation. This is similar to what happens with utility-scale solar. The utility develops demand forecasts and solar energy forecasts and uses this information to develop operating plans. RMP could therefore develop a forecast of CG, which would be built on load forecast plus resource/solar data and history.

Q. Why is it relevant that CG solar is an as-available resource?

A. CG solar is variable and is therefore qualitatively similar to wind and solar generation, and they all possess the characteristics of variability and uncertainty. Uncertainty is managed by utilizing forecasts for all wind and solar generation, along with other forecasts of system conditions, weather, and other factors that influence power system operations. Wind and solar generation are modeled as variable resources within utility IRPs, as in PacifiCorp's 2019 IRP. These resources receive a lesser capacity value than other resources, largely because of their "as available" characteristics.

Despite being qualitatively similar, CG solar is quantitatively different than wind and solar generation because its output is reduced by the customer-owner's own consumption. Accounting for the deduction of on-site customer demand would reduce the value of the CG solar relative to a pure solar resource, but it will nevertheless have some value on the RMP grid. Existing methods and data sets can be used to calculate the impact that CG solar would have on resource adequacy and its capacity contribution.

Q. RMP's argument appears to be that CG solar generation is variable and therefore cannot be counted on to displace capacity. Do you agree?

A. No. Variable resources, which include most forms of solar generation, wind generation, and hydro generation, all have some capacity contribution. However, depending on the resource characteristics, the resource may have a relatively low fraction of its nameplate capacity contribute to resource adequacy. There is a large body of work, developed by various industry and academic task forces at the IEEE Power and Energy Society[45] and NERC,[46] that utilizes loss of load probability ("LOLP") models to calculate the effective load carrying capability of wind and solar resources. This proves that RMP

[45] The IEEE Power and Energy Society approved a Task Force Paper on the capacity value of wind energy. *See* Andrew Keane, et al., *Capacity Value of Wind Power*, IEEE (2011), https://ieeexplore.ieee.org/document/5565546. Other authors have addressed solar energy. *See* Roisin Duignan, et al., *Capacity Value of Solar Power*, IEEE (2012), https://ieeexplore.ieee.org/document/6345429.
[46] *Methods to Model and Calculate Capacity Contributions of Variable Generation for Resource Adequacy Planning*, North American Elec. Reliability Corp. (2011), https://www.nerc.com/files/ivgtf1-2.pdf.

is incorrect in its assertion that a variable resource does not contribute to resource adequacy.

Q. How is the mathematics of risk used to calculate CG solar capacity value?

A. Variable resources, including CG solar, have capacity value based on probabilistic modeling that calculates the risk of having insufficient resources to meet demand. This framework is well-accepted by the IEEE Power and Energy Society[47] and NERC.[48] The modeling can account for variability and focuses on the actual physical and probabilistic behavior of renewable, and other, resources. This is done in the framework of resource adequacy analysis with the contribution of a resource to resource adequacy referred to as effective load carrying capability ("ELCC").[49] The class of modeling tools that calculate ELCC includes long-term reliability models, generation expansion models, and operational models, which all use a LOLP metric[50] to calculate the long-term reliability of a resource portfolio. ELCC represents a resource's contribution to the reliability objective.

Because CG solar is considered "residual" generation, available after on-site demand has been met, it would be expected to have a capacity contribution that is lower than an equivalent solar-only resource. The CG generation is an as-available resource, so for non-zero values of CG, there is potential that the CG solar could reduce loss of load ("LOL") risk, albeit less than the solar-only equivalent resource. Utilizing the mathematics that are embedded within LOLP models is the only way to accurately assess the avoided capacity

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[47] *See supra* note 45.
[48] *See supra* note 46.
[49] There exist other related, similar metrics, but effective load carrying capability is most widely used.
[50] I describe LOLP and other reliability metrics in my testimony below.

made possible by CG solar. Generally, *any* additional MW of generation during a time of loss-of-load ("LOL") risk will have a positive capacity contribution.

Q. Please describe resource adequacy.

A. Resource adequacy is a term that refers to having sufficient resources—generators, demand response, storage, power purchase agreements—to meet demand at some future time or over some planning horizon. All resources, regardless of their type, can fail unexpectedly, and these failures are typically accounted for by the use of probabilistic analyses and planning models that utilize information about these failure rates—called "forced outage rates"—to calculate the risk of not having sufficient resources. The basic algorithm that is utilized in these models calculates metrics such as LOLP or "loss of load expectation" ("LOLE").[51] Risks arising from LOL events are denoted LOL risk. In the context of resource adequacy, the only LOL risk that is relevant is caused by insufficient investment in (or otherwise acquiring) resources. These terms refer to probabilities and expected values (in the probabilistic sense) that help assess the level of resource adequacy. Forced outage rates vary by technology, vintage, and unit size, and extensive data is archived at NERC, which is the official Reliability Organization in the United States. Large coal plants can have forced outage rates of 10-15%, and natural gas plants' outage rates are typically less than half of that. In all cases, any particular unit may have a forced outage rate significantly higher or lower than would be typical for its size, type, and vintage.

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[51] There are numerous related metrics that are calculated in the same stochastic framework. They include loss of load hours ("LOLH"), loss of load events ("LOLE"), expected unserved energy ("EUE"), and other derivative metrics. For the purpose of this discussion, I focus on LOLE, but the discussion is also relevant for other related reliability metrics.

It is important to note that any *particular* resource may be unavailable to produce power during periods of LOL risk. Forced outages can occur at any time and can involve any resource. Even for a resource that has a very low forced outage rate, there is no guarantee that it will be available during periods of LOL risk. Planning models take this into account, and utilities adopt various targets so that they can test any resource portfolio to ensure resource adequacy criteria are met.

Q. What is the difference between LOLP and LOLE?

A. The LOLP metric is a probability, and therefore is between 0 and 1, inclusively. It is calculated by a resource adequacy model and uses the level of demand, resource capacity and forced outage rates, and renewable energy data, including CG. The calculation is done for every hour of the year, with multiple years of data providing a more robust result.

Using a simple coin toss as an example, the probability of tossing a coin and having it land on "heads" is 0.5. If one were to toss this coin 10 times, one would expect 5 heads from the experiment. Thus, 5 heads is the expected value of tossing a head for 10 trials = (probability of a head) x (number of coin tosses). LOLE is similar to the expected number of heads calculated based upon a probability and a number of trials. Similarly, LOLE is calculated using a LOLP and a time period, which is often expressed as days per year.

Q. How is resource adequacy determined?

A. First, a target level of reliability—LOLE or similar—is chosen. Then, the portfolio of resources is modeled, and the LOLE is calculated to determine whether the portfolio achieves the desired reliability level.

A common resource adequacy target is LOLE = 1 day/10 years, but data limitations often constrain the analysis to attain a target of 0.1 day/ year.[52] A target of 1 day/10 years means that one would expect—in the probabilistic sense—that there would be insufficient generation for one day in every 10 years, resulting in curtailed demand for electricity.[53] In the context of resource adequacy, this potential curtailment of demand is calculated to be only as a result of building, or otherwise acquiring or contracting, insufficient resources. The presumption is that one outage every ten years will be acceptable to society, because achieving a higher level of reliability (lower level of risk) is more expensive than society is willing to pay. Thus, the resource adequacy target is fundamentally a policy decision made by some combination of the utility, regulator, or society in general. A smaller target translates into a higher reliability of supply. However, reliability is expensive, so the policy decision must balance the desire for more reliability against the increased cost of more reliability. In addition to choosing the target, policy makers can choose from among the various metrics that are commonly calculated and output from LOLE models.[54]

Q. What happens if a resource is not available during high-risk time periods?

A. With a system that successfully achieves the prescribed reliability level, especially relatively large systems like that of PacifiCorp, it is possible or even likely that during the time of highest LOL risk, one or more resources will experience a forced outage, therefore not generating any output. However, the system is built to withstand some relatively small

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[52] I note that 0.1 day/year is not the same reliability level as 1 day/10 years.

[53] In reality, the grid operator may choose to avoid disconnecting customers and run at lower nominal voltage and/or reduce operating reserves. However, this latter approach puts the entire system at risk.

[54] Michael Milligan, et al., *Capacity value assessments of wind power*, 6 WIREs Energy and Env't (2017).

level of unavailability, and the probabilistic algorithms of LOLP models can rigorously calculate that risk. If a system falls short of achieving its reliability objective, then additional resources must be added to the portfolio so that the desired reliability level is attained. It is important to emphasize that any resource can fail at any time, and the data and mathematics behind a rigorous LOLE modeling analysis can show the reliability impact of the resource portfolio, even when accounting for potential failures from individual resources at critical times.

Q. How are resources such as wind and solar generation handled in resource adequacy calculations?

A. Renewable energy sources, such as wind and solar energy, typically have mechanical and electrical forced outage rates that are near zero; however, their "fuel" varies through time. This means that a robust LOLE modeling framework that includes renewable sources must incorporate time-varying wind or solar energy output so that the variability aspect of the renewable resource is accounted for.

Q. What is ELCC, and how is it related to resource adequacy?

A. In my Affirmative Testimony, I described the ELCC of a generator.[55] The ELCC represents the increase in demand that can be served by a resource, holding reliability constant, and is calculated using a LOLP model. Solar and wind resources have been shown to contribute to capacity on an as-available basis, thereby reducing the LOLP and contributing to long-term reliability and resource adequacy.[56] The NERC has

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[55] *Milligan Affirmative*, line 381.
[56] *See supra* note 45.

recommended the use of LOLP models and ELCC to calculate the capacity contribution of wind and solar energy.[57]

The mathematics of the LOLE calculation will correctly account for the availability of the resource, even though CG solar may not have the same generation pattern as other, more conventional, resources. An hourly calculation of LOLE with an accurate input data set will correctly find the contribution that CG solar makes to improving system risk. As NERC puts it:

> Because variable generation resources have a variable and stochastic nature, methods that can account for these characteristics are not only appropriate, they are necessary to obtain an accurate risk-based assessment of resource adequacy. We therefore recommend the use of LOLP, LOLE, or related metrics for resource adequacy calculations and for determining the capacity contribution of VG [Variable Generation] an all generators.[58]

Generally, wind and solar generation provide some fraction of their nameplate capacity as ELCC. A recent journal article from the International Energy Agency Task 25 Research Group calculates the ELCC of transmission-connected wind energy in different regions of the Western Interconnection ranging from approximately 5%-15% of rated capacity; transmission-connected solar ELCC values range from about 30%-60%.[59]

LOL risk will be reduced any time an additional MW of capacity appears on the system during times of risk. CG solar may be viewed as a residual level of power and energy after on-site usage is supplied. This means that the CG solar is delivered on an "as available"

[57] *See supra* note 46.
[58] *Id.*
[59] *See supra* note 54. These calculations were performed on a regional basis, not for individual utilities.

basis to the RMP system. Fundamentally, this is no different than solar energy from a conventional plant—the difference is in the magnitude and timing of the resource.

Q. Is there a threshold of minimum availability that must be reached by a resource so that it can receive a capacity contribution, or conversely, result in an avoided generation capacity cost?

A. No. It is possible that a resource could receive a capacity contribution of 0. However, resource adequacy can be improved even with resources that have high forced outage rates. A research paper I co-authored in 2005 used a detailed LOLP model that showed that a resource adequacy target could be achieved with a large number of resources, even if many of these resources had forced outage rates reaching 0.90.[60] This modeling shows that resources with low forced outage rates contribute more to portfolio reliability than resources with high forced outage rates. The modeling also shows that even resources with very high forced outage rates can contribute to reliable portfolio performance, albeit at a lower (perhaps much lower) ratio of its installed capacity.

It is important to take this in context. I do not recommend that utilities look for resources with high forced outage rates. However, I do recommend that resources be assessed quantitatively with appropriate, rigorous LOLP models and data so that even modest contributions to resource adequacy can be quantified correctly.

[60] Michael Milligan & Kevin Porter, *Determining the Capacity Value of Wind: A Survey of Methods and Implementation*, Nat'l Renewable Energy Lab. (2005), https://www.nrel.gov/docs/fy05osti/38062.pdf.

Q. If two resources are evaluated to find their ELCC, does the order in which they are added to the LOLP model have any impact on the ELCC of the resources?

A. Yes. The order in which resources are evaluated will make a difference, especially if the resources in question are wind, solar, or CG solar. The ELCC of a resource is calculated based upon a level of risk, LOLE, of the system. CG and solar energy production are correlated. Therefore, because the system risk over a year is the summation of hourly risks, solar resources can saturate some time periods. By this I mean that the first CG added to the system will reduce LOL risk at certain hours of the year. Adding a second CG that is correlated to the first will not reduce risk as much because the first CG has already reduced the risk during those time periods. If the resources are added in the reverse order, then there ELCC values will both change because of this declining marginal contribution to adequacy. This is similar to the issue that I described above in the context of "baking in" resources to the GRID model.[61]

Q. Can you summarize your rebuttal testimony above on capacity contribution?

A. Resource adequacy and capacity contributions are closely linked via the loss of load expectation/probability modeling that is recommended by both the IEEE and NERC. CG solar is an "as-available" resource and is variable; however, these attributes are accounted for in the mathematics of resource adequacy and ELCC calculations. In fact, NERC recommends these methods because they do account for resource variability. Renewable

[61] *See supra* at lines 114–131.

resources are generally expected to have ELCC values that are some fraction of installed capacity—generally less than conventional resources.

VII. SUMMARY OF RECOMMENDATIONS

Q. Please summarize your recommendations.

A. I recommend that the Commission (1) adopt the OFPC method used by Vote Solar to calculate the avoided energy cost of CG solar instead of RMP's approach, which relies on historical data and (2) require future OFPC development to include the best-available information about the EIM. The Commission should reject RMP's inclusion of integration costs as part of the avoided energy cost because doing so is discriminatory unless—and until—RMP can develop a robust method that can be applied to all resources. I also recommend that the Commission accept the Vote Solar approach to calculating the capacity value of CG solar energy and direct RMP to develop and refine its LOLE modeling so as to provide a better assessment of CG solar for the future. This method should also be used to assess the capacity contribution of all resources.

Q. Does this conclude your rebuttal testimony?

A. Yes.

CERTIFICATE OF SERVICE

I hereby certify that on this 15th day of July, 2020 a true and correct copy of the foregoing was served by email upon the following:

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