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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**

SURREBUTTAL TESTIMONY OF MICHAEL MILLIGAN, PH.D.

ON BEHALF OF

VOTE SOLAR

September 15, 2020

REDACTED AND PUBLIC VERSION

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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 surrebuttal testimony?

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

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

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

Q. Please summarize your education 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 my Revised Affirmative Testimony, 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 and Rebuttal 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 respond to the Rebuttal Testimony of Rocky Mountain Power ("RMP" or the "Company") witness Daniel J. MacNeil filed on July 15, 2020, the Rebuttal Testimony of the Office of Consumer Services ("OCS") witness Philip Hayet filed on July 15, 2020, and the Rebuttal Testimony of the Division of Public Utilities ("DPU" or the "Division") witness Robert A. Davis filed on July 15, 2020.

III. SUMMARY OF RECOMMENDATIONS

Q. Please provide a brief summary of your recommendations.

A. First, I recommend that the avoided energy cost of CG solar be calculated using PacifiCorp's Official Forward Price Curve ("OFPC"), as I argued in my Revised Affirmative Testimony.[1] RMP's calculations were based upon the GRID model, which it has indicated it plans to retire. The GRID model has numerous deficiencies and lacks transparency, and likely underestimates avoided cost. In addition, RMP uses historical prices from the Energy Imbalance Market ("EIM") to assess and shape future avoided cost. As I have stated in my prior testimony, that is not an appropriate approach because a backward-looking price cannot account for future changes to the grid. I also demonstrate inconsistencies that arise from RMP's approach to shaping the avoided cost based upon EIM pricing.

Second, I recommend that the Commission accept the avoided capacity cost that I have calculated. RMP's approach assumes that the uncertainty of the timing and magnitudes of loss of load risk will occur in precisely the same way as the single-year construct in the LOLP modeling. That is not reasonable. Additionally, RMP's analysis does not recognize the impact of the order in which a resource is modeled on its capacity value. PacifiCorp's 2019 Integrated Resource Plan ("IRP") is misleading when it presents incremental solar capacity value as dropping precipitously for each 1,000 MW of additional solar generation, and RMP's proposed valuation prioritizes yet to be

[1] Vote Solar, *Revised Affirmative Testimony of Michael Milligan*, May 8, 2020, lines 188-228.

deployed resources over existing CG resources. It appears that PacifiCorp is attempting to rectify that problem in its 2021 IRP, which I describe below at lines 422-36.

My lack of comments on any components of other parties' direct, affirmative, or rebuttal 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. Why is using the OFPC to calculate the avoided energy cost of solar energy better than using the GRID model?

A. In my Rebuttal Testimony I identified several issues with the GRID model that undermine confidence that it can adequately calculate avoided energy cost.[2] One example can be found in GRID output provided by RMP.[3] This shows that [redacted] This

[2] Vote Solar, *Rebuttal Testimony of Michael Milligan*, July 15, 2020, lines 90-96.

[3] RMP Workpapers DJM 6 – UT136 Export Credit, Grid AC Study [CONFIDENTIAL], Docket No. 17-035-61 Phase 2, filed Feb. 3, 2020.

is an implausible result because solar generation occurs during the day; during peak hours in summer months, coal generation is generally not on the margin and electricity prices are relatively high.[4] Coal generation is generally not on the margin—other more expensive resources would be turned down first.

Q. In your Rebuttal Testimony you address the lack of granularity in the GRID model and RMP's method of using prices from the EIM to allocate avoided cost across the hours of the year.[5] What is the significance of using EIM prices in this way?

A. Using EIM prices in the way MacNeil describes in his Rebuttal Testimony[6] results in implausible results and is not consistent with PacifiCorp's own price forecasts.

Q. Please explain why applying EIM prices results in implausible results.

A. The implausible results are caused by the method used to allocate avoided costs. To illustrate, I provide a simple example using a four hour time period. The following table shows the example calculations.

[4] For example, OFPC prices are shown in my Revised Affirmative Testimony. *Milligan Revised Affirmative*, line 636.
[5] *Milligan Rebuttal*, lines 99-113.
[6] RMP, *Rebuttal Testimony of Daniel J. MacNeil*, July 15, 2020, lines 84-88.

1	**GRID Model**						
	Hour		**1**	**2**	**3**	**4**	
	Avoided Quantity (MWh)		0	40	20	0	
	Avoided Cost		0	$480	$600	0	GRID results
	Avoided Cost / MWh		0	$12	$30	0	
	Total Avoided Cost	$1,080					
	Total Avoided MWh	60	This is the monthly data output from GRID - aggregated				
	Monthly Avoided Cost/MWh	$18	on a monthly basis and an average avoided cost				
2	**EIM Prices**						
	Hour		**1**	**2**	**3**	**4**	
	Price $/MWh		$10	$12	$30	$60	Computed using historical data
	Average EIM Price	28					
	EIM Scalar		0.36	0.43	1.07	2.14	Derived using MacNeil's approach
3	**Shaped GRID Price**						
	Hour		**1**	**2**	**3**	**4**	
	Average GRID Avoided Cost		18	18	18	18	Scaled prices in hours 2 and 3 are too low.
	Scaled GRID Avoided Cost		6.43	**7.71**	**19.29**	38.57	(Because prices in hours where there are no avoided costs
							are included in the calculation of the scalars.)
	Average Scaled GRID Price	18					
4	**EIM Scalars Limited**						
	To Hours of Solar Production						
	Hour		**1**	**2**	**3**	**4**	
	Price $/MWh		$10	$12	$30	$60	
	Average EIM Price	21		The average EIM Price is different than the Average GRID price			
				because GRID price is weighted by quantities, whereas EIM price is not.			
	EIM Scalar			0.57	1.43		New set of scalars computed using only
							prices in hours with avoided costs are different.
5	**Shaped GRID Price**						
	To Hours of Solar Production						
	Hour		**1**	**2**	**3**	**4**	
	Average GRID Avoided Cost			18	18		
	Scaled GRID Avoided Cost			**$10**	**$26**		Hourly prices closer to actuals but still too low.
							Scalars based on a straight average of prices but
	Average Scaled GRID Price	18					GRID average price based on weighted average.

Table 1. Example price allocation using RMP's method

In Part 1 of the table is a four-hour period that represents GRID results of calculating the avoided cost of CG solar. In hours 1 and 4, there is no solar generation. In hour 2 there is 40 MWh of generation that results in avoided cost of $480, or $12/MWh. In hour 3 there is 20 MWh of generation with avoided cost of $600, or $30/MWh.

Because GRID produces monthly results that are used in RMP's allocation method, the output is summarized as $1,080 total avoided cost, 60 avoided MWh, and average avoided cost of $18/MWh for the month.

In Part 2 of the table there are EIM prices from the same four hours. The prices average $28/MWh. Using the method described by Mr. MacNeil, the EIM scalars are calculated, and range from 0.36 to 2.14.

Part 3 of the table shows how RMP's use of EIM prices in its shaping algorithm allocates the avoided cost to each of the four hours. Starting with the average GRID avoided cost of $18/MWh from Part 1 of the table, we apply the EIM scalars from Part 2, resulting in the scaled GRID avoided costs that range from $6.43/MWh to $38.57/MWh. The scaled avoided cost in hour 2 is $7.71/MWh, which is much lower than the average of $18/MWh. Because the EIM scalars are applied to all hours—even those hours during which there is no solar generation—avoided costs are too low in hours 2 and 3, and too high in hours 1 and 4.

Part 4 of the table shows an attempt to correct for this by using only prices for hours of solar generation. The average EIM price for hours 2 and 3 is $21/MWh, which is higher than the average avoided cost of $18/MWh. Calculating the EIM scalars results in a scaled avoided cost of $10/MWh and $26/MWh for hours 2 and 3, respectively. However, these values are below the original EIM prices of $12/MWh and $30/MWh, respectively, distorting the relative values.

Part 5 of the table uses the scalars from Part 4, but applies them instead to the average GRID avoided cost of $18/MWh. This approach calculates a scaled avoided cost that is closer to EIM prices, but still falls short. In all of these examples, using this method results in distortions of the relative value from hour to hour.

Q. Please summarize your conclusion from this example.

A. The avoided cost allocation method used by MacNeil and represented in Part 3 of Table 1, distorts costs because some costs are allocated to hours when there is no solar generation. Hours when there is solar generation have avoided costs that are too low. I therefore conclude that this approach is flawed.

Q. MacNeil states that "Vote Solar's avoided energy proposal overstates the value of CG exports" because it assumes that all CG exports can be sold.[7] Is this criticism valid?

A. No. Vote Solar does not assume that all CG exports can be sold. The OFPC is used to place a value on these exports. The prices from three nearby trading hubs are averaged so that a "blended" price can be used to value CG exports. Using a market price to calculate the value does not assume that each kWh is actually sold.

Q. MacNeil states that the EIM prices are more granular than the OFPC, and that the historical EIM price is more representative of the value of CG solar.[8] Is it reasonable to assume that historical EIM prices accurately represent future prices?

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[7] *MacNeil Rebuttal*, line 281.
[8] *Id.* at lines 231-41.

A. No. Participation in the EIM is changing, with more utilities joining the market. In 2019, the Balancing Authority of Northern California joined the EIM. In 2020, Salt River Project and Seattle City Light both joined. Several new entities will join in 2021 and 2022.[9] In addition to broader participation, it is likely that an enhanced day-ahead market ("EDAM") will be developed in the near future and will have a further impact on EIM prices.

Q. Given these changes in EIM membership and market structure, would a historical EIM pricing pattern, such as the one used by RMP in this proceeding, have a strong correlation to future EIM pricing?

A. No. There would likely be significant differences, and the use of historical EIM pricing would not be valid to represent future prices. A historical EIM price strip reflects the generation and demand patterns from that specific year, broken down in 5-minute or 15-minute time steps. Generation patterns—*i.e.*, the mix of generation online during any given time—along with demand, will determine the equilibrium price. Because of the significant changes that are unquestionably going to occur in the power system in the West during the next decades, it is increasingly likely that significantly more renewable generation will come online and significantly less coal will be online. This is confirmed by PacifiCorp's 2019 IRP, which shows a significant change in PacifiCorp's own fleet of generating resources.[10] In addition to these changes in

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[9] Western Energy Imbalance Market, *About*, https://www.westerneim.com/Pages/About/default.aspx.
[10] *2019 Integrated Resources Plan*, PacifiCorp, Volume I, Chapter 1, p. 3, Oct. 2019, https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificorp/energy/integrated-resource-plan/2019_IRP_Volume_I.pdf.

PacifiCorp's resource mix, there are similar trends among other neighboring utilities, and there will also be changes in the transmission system over time. Transmission additions will generally reduce congestion, and therefore will have an impact on EIM prices. Taken together, it is implausible that historical EIM prices could accurately represent a forecast of future prices in the West.

Q. Do you have any evidence to support your claim that historical EIM prices are not correlated with future prices?

A. Yes. I compared the hourly EIM prices from 2017 with the inflation-adjusted OFPC from 2022 from the three trading hubs that I used in my Revised Affirmative Testimony to calculate the avoided energy cost of CG solar.[11] The OFPC represents PacifiCorp's best estimate of future prices, as I have previously stated.[12] The year 2022 is within the time horizon during which PacifiCorp transitions its price forecasts to a blended approach.[13] In 2022, the resource mix in the West will have changed significantly compared to the three-year period ending November 1, 2019, which is the period during which RMP selected historical EIM prices. PacifiCorp's modeling with AURORA accounts for these changes, whereas the historical EIM prices do not.

I first adjusted the 2022 OFPC prices for inflation, and used PacifiCorp's inflation rate of 2.28%.[14] I then calculated both the average real price for the EIM and OFPC price

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[11] The 2017 EIM prices came from S&P Global Market Intelligence; SNL Energy Data.
[12] *Milligan Rebuttal*, lines 180-81.
[13] *2019 Integrated Resources Plan*, PacifiCorp, Volume I, Chapter 7, p. 180, Oct. 2019, https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificorp/energy/integrated-resource-plan/2019_IRP_Volume_I.pdf.
[14] *Milligan Revised Affirmative*, line 337.

streams, and the correlation between the EIM prices and OFPC. The average real EIM price for 2017 is $33.12/MWh and the average inflation-adjusted OFPC is [redacted]. The correlation between these two prices is 0.025. Correlation values can range from -1.0 to 1.0. Larger positive values or smaller negative values occur when the correlation is stronger. A correlation that is close to zero indicates there is no particular relation between the two data sets. In this case, a correlation of 0.025 indicates a lack of correlation between EIM prices and the OFPC.

Q. What do you conclude from this analysis?

A. Using historical EIM prices in any analysis of future pricing of electricity is flawed because these prices do not reflect the changing nature of the grid. In addition, there is no significant correlation between 2017 EIM prices and 2022 OFPC prices, which indicates that pricing patterns from past years will change as the grid evolves through time. This is verified by my analysis of 2017 EIM prices and OFPC prices.

Q. But how can one predict what future prices will be?

A. PacifiCorp has incorporated into the OFPC what RMP has represented is the best possible information about what future prices will be. 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*."[15]

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[15] RMP, *Rebuttal Testimony of Rick T. Link*, Idaho Public Utilities Commission, Case No. PAC-E-17-07, at 2, Dec. 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 (emphasis added).

The following table shows key changes in the power system over the next several years and which of these changes are taken into account by the historical EIM prices that RMP used, compared to the OFPC.

Changing Attributes of the Future Power System	Accounted for in historical EIM price (Y/N)	Accounted for in OFPC (Y/N)
Coal retirements	N	Y
Increasing renewables	N	Y
Changes in demand	N	Y
Changes in natural gas prices	N	Y
Changes in transmission network	N	Y
Changes in reserve margins	N	Y
Changes in gas pipeline tariffs	N	Y
Generic, unspecified technology changes or EIM market evolution	N	Y

Table 2. Changes accounted for by EIM v. OFPC prices

Given the pace of change of the grid in the West, we know that the past will never be repeated. Utility planning processes such as that undertaken by PacifiCorp, supplemented by those at the Western Electricity Coordinating Council ("WECC"), are not perfect, but they provide the best available information with which to assess the future.[16]

Q. OCS Witness Hayet states that both the OCS and RMP used a later version of the OFPC for their respective analyses than was used by Vote Solar.[17] Doesn't that invalidate your calculations?

A. No. It is not necessary, nor is it practical, to update the avoided energy cost with each new version of the OFPC while this proceeding is pending. The OFPC is updated on a quarterly basis, and I have used the December 31, 2019 version in my analysis.

Q. MacNeil states the the OFPC reflects a premium for price and volume certainty, and therefore does not apply to CG solar.[18] Do you agree?

A. In its response to Vote Solar's Data Request 12.3 (7), RMP states: "PacifiCorp's OFPC is composed of 37 months of market forwards followed by 12 months of forwards blended with fundamental forecast prices that transition to a pure fundamentals forecast starting in month 50. The fundamentals are modeled using AURORA, a WECC-wide zonal linear programing model that optimizes total production costs subject to operating and transmission constraints. Transmission capabilities are modeled between zones, based on capabilities modeled by Energy Exemplar, the developer of AURORA."[19] This indicates that prices beyond 49 months

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[16] WECC is the only entity in the West that hosts collaborative planning processes for the interconnection. *See* WECC, *About*, https://www.wecc.org/Pages/home.aspx.
[17] OCS, *Rebuttal Testimony of Philip Hayet*, July 15, 2020, lines 316-17.
[18] *MacNeil Rebuttal*, lines 281-84.
[19] *Milligan Rebuttal*, Vote Solar Exhibit 1-MM, filed July 15, 2020.

into the future are calculated by a production simulation program, AURORA, and does not indicate any risk-adjusted prices.

Vote Solar sent a data request to RMP requesting hourly adjustments or other factors that Vote Solar could use to calculate the impact of this premium. In response, RMP stated that "PacifiCorp has not prepared calculations to identify the risk premium in each hour."[20] RMP instead provided data for both risk-adjusted and non-risk-adjusted monthly average prices. I calculated the monthly "markup" ratio for both the high-load hours and the low-load hours ("HLH" and "LLH," respectively), and found that the average markup was 1.03 for LLH and 1.11 for HLH. Based upon these average markups, there would be a reduction in the avoided energy cost of approximately 7%. If accurate, this would reduce my original estimate of avoided energy cost from 3.55 cents/kWh to 3.32 cents/kWh.

This data, however, is not consistent with RMP's response to Vote Solar Data Request 15.2. The data is not granular enough to use in a meaningful way because it provides only one price per month for load load hours and for high load hours, whereas the OFPC prices are hourly. The ratio of the prices that include risk to prices without risk varies from 0.63 to 1.47 for low load hours, and from 0.64 to 2.46 for high load hours. If accurate, this means that for a full month the price premium is a negative 37% for low load hours, and is similar for high load hours. For high load hours the price premium in August of 2029 is 246%. These figures are just not plausible.

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[20] Exhibit 1-MM, *Response to Vote Solar Data Request 15.2*, Responses to Vote Solar 15th Set of Data Requests (Aug. 14, 2020).

Q. DPU Witness Davis states that Vote Solar's avoided cost calculation is not consistent with utility-scale solar PPAs.[21] Does this mean utility-scale PPAs should be used to establish the avoided energy cost of CG solar?

A. No. There is no reason why distributed PV and utility-scale PV costs should be the same; they are different resources with different economies of scale. Davis ignores locational and other value associated with CG. Power Purchase Agreements ("PPAs") also do not provide valid bases for comparison in part because there is not a one-size-fits-all PPA. Some PPAs may include transmission costs, whereas others might not. Large-scale projects can require investment in infrastructure to maintain reliability whereas such investments are not needed for CG. CG solar avoids nearly all transmission cost, whereas utility-scale solar does not. The comparison is not apples to apples. Further, the electric system is more reliable and resilient with a diversity of generation resources at different locations.[22]

Q. Please summarize your surrebuttal testimony regarding avoided energy costs.

A. The GRID model is not transparent in its calculations and likely underestimates the avoided energy cost of CG solar because it shows a significant displacement of coal generation during peak periods. The allocation of avoided costs to the hours in the year based on RMP's method is also flawed, and results in avoided costs that are not

[21] DPU, *Rebuttal Testimony of Robert A. Davis*, July 15, 2020, lines 191-97.
[22] A. Bloom, H. Holttinen, U. Helman, K. Summers, J. Bakke, G. Brinkman & A. Lopez, *Five indisputable facts on modern power systems*, IEEE Power and Energy Society General Meeting, July 2017, https://www.nrel.gov/docs/fy17osti/68947.pdf.

consistent with CG solar generation. The use of EIM prices further distorts the allocation process, because EIM prices do not represent future changes to the power system.

V. Avoided Generation Capacity Costs

Q. MacNeil and Hayet state that Vote Solar's inclusion of avoided capacity costs for CG solar imposes a risk on RMP's non-CG customers because CG customers have no obligation to provide any level of exported energy.[23] How do you respond?

A. Hayet's argument fails to recognize the fact that RMP is the sole possible buyer of CG solar exports. As I stated in my Rebuttal Testimony, CG customers are captive consumers and producers and cannot sell their excess solar power in any other market or to any other utility. This creates a market structure known as a monopsony.[24] Even though CG is dependent upon the customer's demand, it is still an as-available resource, which is delivered to RMP's grid whenever it is available. Although the exports from CG to RMP differ from the total on-site generation in terms of timing and magnitude, Vote Solar's analysis accounts for this by focusing on the chronological CG output. This as-available nature of CG exports is qualitatively the same as any other solar resource, including, for example, Qualifying Facilities ("QFs"), which are also as-available resources. Therefore, because the customer's own load is served first (thus reducing demand on RMP's system, including peak demand, during the period of such

[23] *MacNeil Rebuttal,* lines 740-42, *Hayet Rebuttal*, lines 572-77.
[24] *Milligan Rebuttal*, lines 563-65.

use), the exported CG energy would be less than the customer's load; hence it is quantitatively different than solar generation, but qualitatively the same.

When a customer acquires on-site generation, an investment is made in the resource that will deliver benefits over many years. Although some of these benefits accrue to the customer in terms of lower electricity cost, there is some residual benefit that is transferred to RMP via CG exports as well as benefits from CG behind-the-meter consumption reducing peak demand and hence investments required to satisfy peak demand. CG therefore provides long-term benefits to the individual customer and also to RMP. Focusing on solely CG exports, as Vote Solar does in its analysis, results in some of the long-term benefits that CG provides to RMP being undervalued since the reduction in RMP's capacity requirements is made possible by *total* CG generation, not just CG exports.

Q. Davis states that Vote Solar's capacity value "seems high given the non-dispatchable nature of CG compared to utility-scale solar," and that the capacity contribution calculation "does not appear consistent with other established solar capacity values."[25] Do you agree with that statement?

A. No. Davis offers no evidence to support this statement. Data provided by PacifiCorp in its 2019 IRP, included below (Figure 1), show a range of solar capacity values from a few percent of rated capacity up to nearly 80% of rated capacity.

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[25] *Davis Rebuttal*, lines 223-25.

Q. Davis argues that even though you, Yang, and Volkmann use acceptable methods in your respective analyses, the current CG penetration level in Utah results in "little capacity or pollution avoidance."[26] Does accepting this argument imply that CG solar should not get credit for avoided capacity or emissions, even if the displacement is small?

A. No. Individual residential consumers have an even smaller impact on the capacity requirements of RMP, and yet they are billed for retail electricity at a rate that includes a capacity component. It is important that market signals be provided to both producers and consumers so that all costs and benefits are clearly accounted for. Furthermore, new resources such as wind, solar, and battery storage can be developed in a more modular fashion than some traditional resources that could only be added as large increases in capacity. This means that future resource additions can be made to be in smaller increments, and can therefore more closely match load growth. To the extent that CG mitigates this load growth, adjustments can be made in potential resource additions to match the net demand more closely.

Q. But CG generation is not the same as CG export. Doesn't that invalidate your argument?

A. No. In all of my calculations, I focus only on the *export* levels of CG, which are less (never greater) than the full amount of CG generation. If the full amount of CG solar were to be evaluated, there would be an even larger value of avoided capacity;

[26] *Id.* at lines 177-78.

therefore, the estimates of avoided CG export capacity contribution are conservative because they exclude the benefit of the solar generation reducing net demand for the utility. In addition, if storage were to be added to CG systems, the capacity contribution would increase even further.

Q. MacNeil criticizes your effective load carrying capability ("ELCC") approximation method because it does not consider the declining contribution of solar as its penetration increases on the grid. How do you respond?

A. My ELCC approximation method assumes that incumbent CG resources should be evaluated prior to solar plants that have yet to be deployed. The level of CG Vote Solar evaluated is online today, and therefore should not be subject to the declining capacity contribution MacNeil refers to. The impact of this can be seen in data presented as part of PacifiCorp's 2019 IRP.

PacifiCorp, in its 2019 IRP analysis, evaluated several different portfolios that include both wind and solar energy. Table N.1 shows "blocks" of wind and solar power, and each block of power is shown alongside its capacity contribution.[27] This table is reproduced here as Table 3, and shows the declining capacity contribution of wind and solar energy as calculated by RMP in 2019.

[27] *2019 Integrated Resources Plan*, PacifiCorp, Volume II, Appendix N, p. 401, Oct. 2019, https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificorp/energy/integrated-resource-plan/2019_IRP_Volume_II_Appendices_M-R.pdf

Table N.1 – ECP Method Capacity Contribution Values for Wind and Solar

Study	Nameplate Capacity (MW)	
	Wind	Solar
No wind or solar	0	0
No wind	0	2,218
No solar	3,722	0
Initial Portfolio	3,722	2,218
Capacity Contribution of Initial Portfolio		
MW	852	955
%	23%	43%
Capacity Contribution of Incremental Resources		
+1000 MW	15%	15%
+2000 MW	12%	2%
+3000 MW	6%	0%
+4000 MW	1%	0%

Table 3. Table N.1 from PacifiCorp's 2019 IRP

Q. Does this table accurately portray the declining capacity contribution of solar energy?

A. No. This table is misleading. As explained in the 2019 IRP, the initial portfolio of resources, which includes 2,218 MW of solar capacity, was modeled and the capacity contribution for this amount of solar energy was calculated to be 955 MW, or 43% of the rated capacity of the solar resource. Subsequent modeling added four blocks of 1,000 MW of solar, one at a time. For each of these incremental 1,000 MW blocks of solar, the incremental capacity value was calculated. As can be seen in the table, the first 1,000 MW of solar, added after 2,218 MW is already on the system, has a capacity value of 15% (of rated capacity), the subsequent one is 2%, and the additional solar capacity value is 0%.

Q. Why is this misleading?

A. The table implies that adding even one additional MW of solar beyond the initial 2,218 MW will result in a capacity value of 15% for that incremental MW, and for the subsequent 999 MW of solar that is added beyond the initial portfolio. This is not true, because the mathematics of LOLP-based methods, such as that used in the 2019 IRP, would not result in large "steps" of decline in capacity value as portrayed in the table. As additional solar capacity is added in smaller increments beyond the initial 2,218 MW, the capacity contribution would decline gradually. In MacNeil's Rebuttal Testimony he shows a graph of solar capacity studies originally presented at PacifiCorp's September 27-28, 2018 IRP public input meeting. That graph, reproduced as Figure 1, shows that the declining capacity contribution of solar does not follow a "step" pattern, as PacifiCorp's 2019 IRP would suggest.[28]

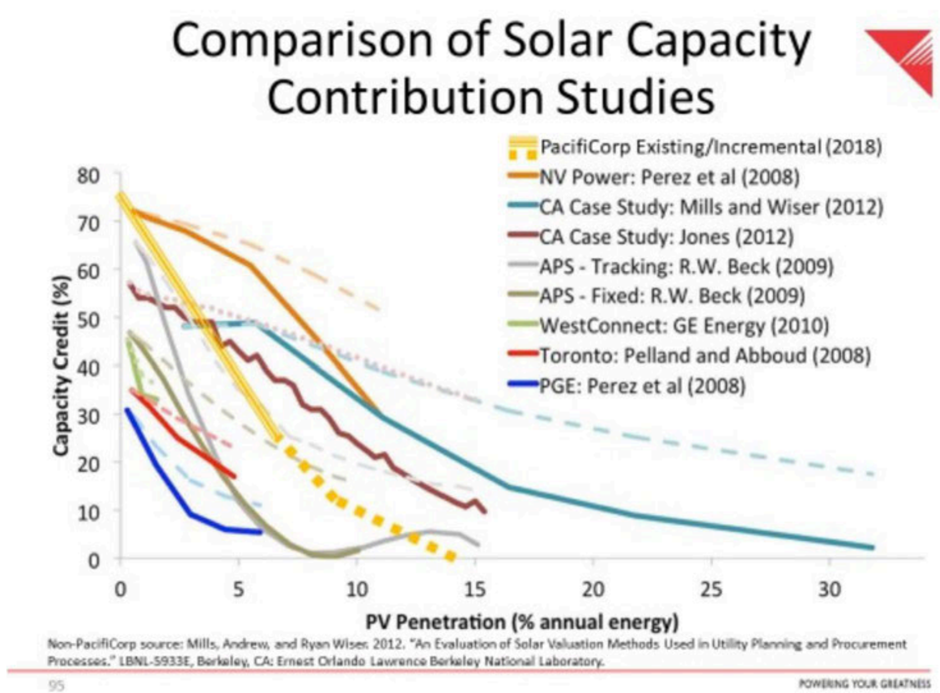

Figure 1. Comparison of solar capacity contribution studies

I created a graph of the PacifiCorp data from Table 3 above, and the result is shown in Figure 2 below. The orange line shows the solar capacity contribution from Table 3, which steps down at each 1,000 MW addition of solar. The blue line shows a linear interpolation, which approximates how the capacity contribution would decline for each additional 100 MW increment of solar energy. I note that the linear interpolation is not exact, but is representative of the way solar capacity contribution changes when additional solar generation is added to the resource mix.

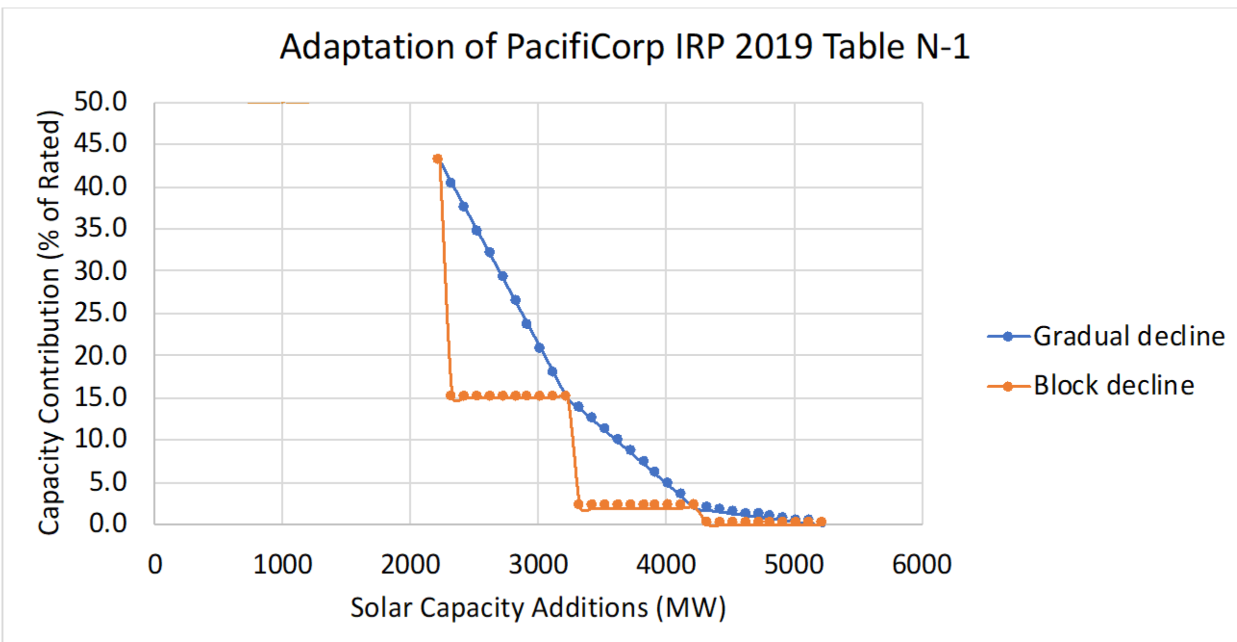

Figure 2. Comparison of IRP table with a gradual decline in solar capacity contribution

From the graph we can see how the data in Table 3 is misleading: it implies that adding 100 MW (for example) of capacity beyond the additional portfolio of 2,218 MW of solar would result in a capacity contribution of 15% of the 100 MW solar addition, 15 MW. If the capacity contribution calculation would have been carried out for each 100 MW increment, as approximated by the blue line in the graph, the capacity contribution of this 100 MW solar addition would have been approximately 25.2%, based on the linear interpolation.

Q. How does this relate to the capacity contribution of CG?

A. Applying the principle that incumbent generation—the existing CG— should be evaluated for its capacity contribution prior to future, yet to be developed resources, CG should be evaluated on the left side of the above diagram. According to PacifiCorp's Table N.1 (Figure 1), the position of CG solar exports relative to the first 2,218 MW in the table would determine whether the CG is subject to declining capacity value. The PacifiCorp installed capacity of solar was at 1,759 MW at the time the IRP was published, and the CG solar also in place. Therefore, the total amount of solar connected to PacifiCorp in 2019 was 2,020 MW, including the CG solar. According to PacifiCorp's own analysis, the CG solar would fall into the first 2,218 MW of solar, which has a capacity contribution of 43%. As additional solar is added to the system, and as indicated in Figure 2, solar capacity value declines gradually.

Q. Did MacNeil address the question of how much solar was operating in 2019 in his Rebuttal Testimony?

A. Yes. He stated that about 850 MW of solar was operating in Utah during 2019 and that contracts have been executed for about 700 MW of additional solar capacity.[29]

[29] *MacNeil Rebuttal*, lines 726-27.

Q. How did MacNeil arrive at his average availability of CG solar during the top 10% of RMP load hours?

A. During 2019 the average CG export was about 22% for the top 10% of load hours.[30] He then multiplied the 2019 solar capacity by 1.8 to account for "capacity that is not yet online" and considers the CG to be added *after* this contracted, but yet to be built solar is accounted for.[31] The result of including future solar prior to evaluating CG exports yields a 4.6% contribution from CG solar exports.[32] This means that MacNeil assumed CG solar would be added to the grid *after* solar units which will not be operating until some point in the future, and therefore CG solar receives an unreasonably low capacity contribution.

Q. MacNeil's rebuttal states that your capacity valuation approach is not related to reliability, and is therefore invalid.[33] Do you agree?

A. No. MacNeil correctly states that when solar energy is added to the system, the risk profile changes because of the impact solar has on net demand. Generally, solar will decrease net peak demand or net near-peak demand.[34] This means that the remaining resources do not need to meet such a high peak or near-peak demand. This ties into the fact that solar energy has a declining capacity contribution as its penetration

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[30] *Id*. at lines 722-23.
[31] *Id*. at lines 727-29.
[32] *Id*. at line 730.
[33] *Id*. at lines 538-40.
[34] If the solar resource is perfectly correlated with demand, then the net peak demand will decrease. Even if the solar resource is not perfectly correlated with demand, it will have some capacity contribution, which generally declines with correlation. However, it is possible that, even if the solar resource does not contribute significantly to the peak hour, it may contribute to other time periods with demand levels only somewhat lower than peak. This is the basis for distinguishing between peak and near-peak demand.

increases. The first increment of solar energy will decrease net peak demand. Subsequently added solar energy will not have the same impact on peak demand, and will therefore contribute somewhat less to capacity needs.

Loss-of-load probability ("LOLP") is a function of several variables, including the level of demand, solar, other generation, imports and exports, maintenance scheduling, and the forced outage rates of all resources in the fleet. However, LOLP is highly correlated with peak demand. Because future demand patterns, solar generation patterns, and their correlations are unknown, utilizing a single year of solar data in an LOLP analysis may create a false sense of accuracy in the calculation. Generally, the high-risk time periods occur during peak and near-peak periods. Given the inherent uncertainty of the future, utilizing an analysis like the one I describe in my Revised Affirmative Testimony that focuses on the top 10% of load hours is appropriate and generally captures reliability over the long-term.[35]

Q. Are there any concerns about using a metric to value capacity that can result in such large variations in capacity contributions based upon the ordering of resources when determining financial payments or credits?

Yes. The capacity contribution of a resource depends heavily on the order in which it is evaluated in the reliability model, as indicated in Figure 2. There are other related consequences, because not only the ordering of evaluation influences the capacity value, but the composition of the existing resource mix (or the resource mix already in

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[35] *Milligan Revised Affirmative*, lines 523-27.

the model) also influence the capacity contribution of the resource in question. PacifiCorp acknowledges these concerns in a recent public input meeting presentation given in connection with the 2021 IRP development.[36]

The discussion in these slides identifies the following issues:

- There is a significant difference in the capacity contribution of a resource based on its relative ordering in the calculation.[37]

- The capacity contribution of variable resources (wind, solar) depends on the resource mix of the balance of the portfolio.[38]

- "PacifiCorp found that portfolios with equivalent assumed capacity contributions were not resulting in comparable levels of reliability."[39]

- Interactions of the portfolio (including solar) with wind and energy storage are complex.[40]

- Solar capacity contribution was previously evaluated as a function of a single variable: solar capacity. Instead, a "multi-variate solution" should be pursued so that solar capacity contribution is calculated "as a function of the characteristics of all other resources (i.e. wind and storage)."[41]

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[36] 2021 IRP Public Input Meeting, July 30-31, 2020, https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificorp/energy/integrated-resource-plan/07-30-31-2020_PacifiCorp_2021_IRP_PIM.pdf.
[37] *Id*. at 43.
[38] *Id*.
[39] *Id*. at 44.
[40] *Id*. at 46.
[41] *Id*. at 47.

Q. Are there any other methodological problems that could arise from this sensitivity to ordering the resource in the capacity contribution calculation?

A. Yes. As an example, consider two identical 1,000 MW solar plants: Plant A and Plant B.[42] Adding either of these solar plants separately to the resource mix would result in an ELCC of 15% of rated capacity,[43] based upon the example in PacifiCorp's 2019 IRP.[44] If Plant A is added first, then its capacity contribution is 15%. Subsequently adding Plant B would result in a capacity contribution of 2% for Plant B, based upon PacifiCorp's estimates in the IRP. However, if Plant B is added to the resource mix before Plant A, then their respective capacity contributions are reversed.

Q. Why is this relevant?

A. The relevance is that the avoided capacity value of each plant in RMP's calculation is dependent upon the order in which it was added to the resource mix. In this simplistic example, we have two otherwise identical solar plants that perform identically, and yet have different capacity contributions, which would translate into correspondingly lower avoided capacity costs. This has the interesting consequence of two identical plants having different avoided capacity costs, but identical performance. If compensation (whether paid directly or via an avoided cost approach) is based upon performance, then the principle of paying for a grid service based on the amount of

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[42] I use solar plants for the example but this also applies to CG solar.

[43] This result would be the same using the equivalent conventional power ("ECP") metric, which PacifiCorp uses in its 2019 IRP.

[44] *2019 Integrated Resources Plan*, PacifiCorp, Volume II, Appendix N, p. 401, Oct. 2019, https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificorp/energy/integrated-resource-plan/2019_IRP_Volume_II_Appendices_M-R.pdf.

service provided is violated. Applying Bonbright's principle of "[f]airness of the specific rates in the apportionment of total costs of service among the different consumers"[45] to the principle of fairly apportioning avoided costs of a service appears to violate the notion of "horizontal equity." The rather arbitrary ordering of resources and resulting violation of the principle of horizontal equity imply that ELCC cannot effectively be translated into a market, nor can it be consistently used to determine avoided capacity payments. ELCC and equivalent conventional power ("ECP") are useful and important reliability metrics. However, some form of proxy should be used to craft a rate that compensates a resource for its capacity contribution.

Q. Did PacifiCorp suggest any remedies to these issues?

A. Yes, but not in this proceeding. Instead, PacifiCorp suggests a remedy in the in-process work on its 2021 IRP. In the public input meeting presentation I discussed above, PacifiCorp describes a method that evaluates the impact of a given resource type, solar in this case, on the contribution to capacity.[46] This is done by differentiating the "first-in" contribution, which is calculated by adding the solar to a portfolio consisting solely of capacity resources.[47] These capacity resources are assumed to have a uniform availability in each hour of the year. This approach removes the complex

[45] J.C. Bonbright, *Principles of Public Utility Rates*, Powell Godstein LLP (photo. reprint 1961), 2005, p. 291, https://www.raponline.org/wp-content/uploads/2016/05/powellgoldstein-bonbright-principlesofpublicutilityrates-1960-10-10.pdf.
[46] 2021 IRP Public Input Meeting, July 30-31, 2020, https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificorp/energy/integrated-resource-plan/07-30-31-2020_PacifiCorp_2021_IRP_PIM.pdf.
[47] *Id*. at 42.

interactions that can occur between multiple solar facilities, solar and wind, or other renewables that may be coupled with storage.

A "last-in" contribution is based upon a resource mix that includes all other portfolio resources.[48] For example, wind and storage might be part of the portfolio resources when solar is added. This last-in measurement captures the marginal contribution of the resource in question, after all other resources have been included in the model.

PacifiCorp proposes a "portfolio contribution" for solar energy, which accounts for both the first-in and last-in calculations.[49] This is shown in Figure 3. This graph differs from Figure 1 only in the indicators for first-in and last-in contributions, and by showing the area under the curve as the portfolio contribution to capacity. The effect of this approach is to calculate the capacity contribution of all solar as a group, and may avoid the problems associated with the different ordering of solar plants in the modeling.

[48] *Id*.
[49] *Id*.

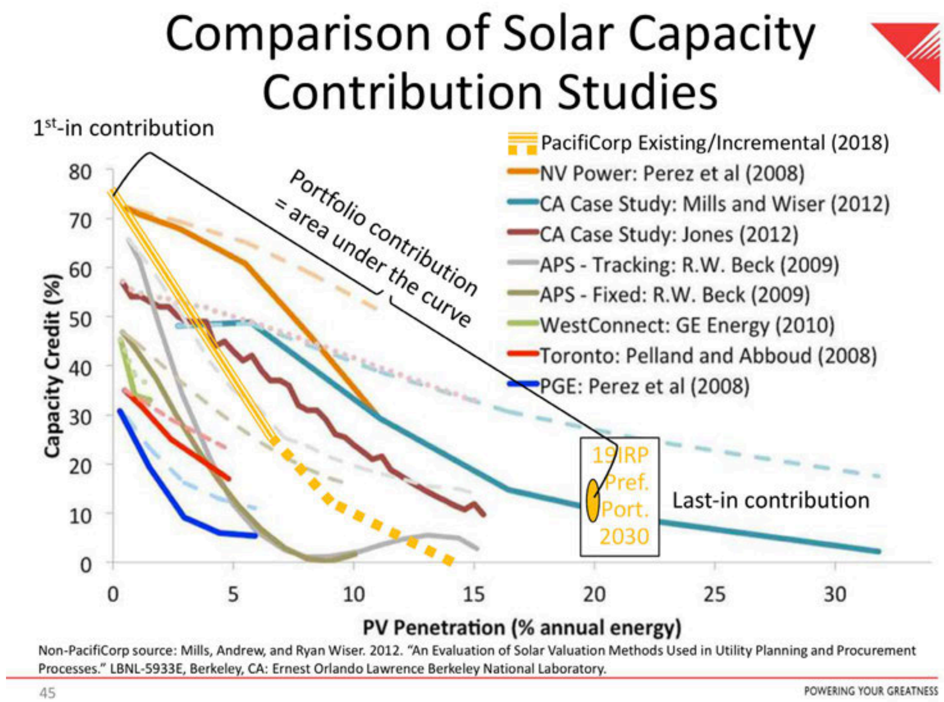

Figure 3. Illustration of portfolio contribution to capacity from 2021 IRP Public Meeting[50]

Q. How would the first-in/first-out analysis evaluate the contribution of individual plants?

A. PacifiCorp does not indicate how, or if, this would be done. However, it would be possible, based upon an assessment of days and hours during which there is loss of load risk, that each plant's capacity factor during this period could be calculated and used to pro-rate the capacity contribution of the resource. The period of loss of load risk should be based upon multiple years in the utility planning horizon, as I explained in my Revised Affirmative Testimony, and not a single year.[51] This makes it possible to estimate long-term capacity contributions. This process removes the arbitrary ordering of resources, recognizes the potential contribution of all solar plants during

[50] *Id*. at 45.
[51] *Milligan Revised Affirmative*, lines 470-73.

periods of risk, and ranks them based upon these contributions. This means that the capacity contribution of a class of resource is calculated for that class, and then apportioned based upon the individual plant performance during periods of risk. Accordingly, RMP's current method for assessing capacity value is flawed.

Q. MacNeil states that the use of the top 10% of load hours implies equal weighting of each hour, when in fact it would be more accurate to weight each hour by LOLE or similar metric.[52] Doesn't that equal weighting make your method less accurate?

A. Not necessarily. Weighting each hour by LOLE may be more accurate in a backward-looking analysis, but it imposes exactly the same conditions on the future as on the past. This is similar to RMP's use of past-year prices to shape future avoided energy costs. If the objective of the analysis is to capture the reliability risk in a *single* year, and with a *fixed* resource mix, I would agree with MacNeil. However, PacifiCorp's 2019 IRP is intended as the foundation for long-term planning of the system, spanning more than two decades into the future. The modeling and analysis that went into the capacity contribution analysis that MacNeil describes was quite thorough. However, it focused on data from a single historical year. As MacNeil states, "[t]he Company has relatively little history for solar resources…,"[53] and because of "the lack of robust historical data, wind and solar generation profiles are modeled based

[52] *MacNeil Rebuttal*, lines 697-700.
[53] *Id*. at line 579.

on actual hourly generation data from a single historical calendar year, with adjustments to align with normal expected output."[54]

Using a single year of data, the hourly LOLP (or any other reliability metric) allows one to precisely describe reliability, the impact of solar, and other variables *for that year only*. However, this single year of data says nothing about what will happen in future years as the weather, solar generation, demand, and all the other variables related to LOLP change. Year-to-year variation can be significant, and can have significant changes on the timing and magnitude of hourly reliability calculations. Unusually hot or cool average annual temperatures can have an influence on demand, wind, solar, and hydro power generation, as can changes in the intensity and location of the prevailing jet stream that brings in weather systems. None of these variations are captured with a single year of historical data that is used to calculate resource adequacy and capacity contribution of resources—especially weather-driven resources such as wind and solar power.

As I stated in my Revised Affirmative Testimony, "[w]ith a limited data set such as that used in the PacifiCorp IRP, a false sense of security may be found in a precise calculation that is based on hourly LOLP values that are likely to be quite different in other years."[55] In principle, I would recommend a multi-year analysis and modeling process, with at least 10 years of synchronized demand, solar, and wind data, using a modeling framework that calculates some combination of loss of load expection

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[54] *Id*. at lines 583-86.
[55] *Milligan Revised Affirmative*, lines 465-67.

(LOLE), loss of load hours (LOLH), expected unserved energy (EUE), or other similar metric. Using a single year of data poses the significant risk that the LOLP analysis, while accurate for a single year, does not capture future reliability impacts on the system. In the absence of multiple years of high-quality solar data, the utility could undertake a more robust risk analysis that identifies time periods of *potential* loss of load risk, and use this to help inform how the solar resource will impact *future* reliability. Applying LOLP weights from a specific year to specific solar generation may accurately assess the solar contribution to capacity in that year, but is unlikely to be accurate for the future.

In the absence of a multi-year data set for CG solar exports, multiple years of demand data can be helpful to identify potential times of loss of load risk. Choosing the top 10% of load hours, as I described in my Revised Affirmative Testimony, provides a way to do this.[56]

My 1997 paper compared equally-weighted load-hours and LOLP-weighted load-hours with ELCC over many years, and found that the equally-weighted approach was more accurate in approximating a long-term assessment of capacity contributions.[57] MacNeil has provided no evidence that PacifiCorp's calculations can accurately capture the interannual variations that will surely influence LOLP and any other reliability metric one might choose to calculate.

[56] *Id*. at lines 506-11.
[57] *Id*. at lines 438-54.

Q. MacNeil states that LOLE may not be the best metric, and therefore your 1997 study may not be valid. Do you agree?

A. No. I do not agree that my 1997 study is invalid. There are important metrics other than LOLE that can also be used to assess capacity value. I led the development of the North American Electric Reliability Corporation (NERC) report on capacity valuation of renewable resources.[58] We recommended the use of alternative reliability metrics to assess the capacity contribution of renewables. I have done additional research on this question, and our findings, subject to additional research, are that the underlying metrics of LOLE, LOLH, or EUE do not produce meaningfully different results.[59] Therefore, while I agree that other metrics should be pursued, the research does not suggest that LOLE should necessarily be replaced by another fundamental metric to calculate ELCC, ECP, or similar assessment of capacity contribution.

Q. MacNeil states that PacifiCorp performed a study with 500 iterations in their resource adequacy calculations.[60] Is that sufficient to assess the capacity value of solar over the planning horizon of the IRP?

A. No. The 500 iterations were based upon sampling from "load, hydro, and thermal outage conditions, based on a portfolio for the year 2030…".[61] These modeling

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[58] North American Electric Reliability Corporation, *Methods to Model and Calculate Capacity Contributions of Variable Generation for Resource Adequacy Planning*, Mar. 2011, https://www.nerc.com/comm/PC/Integration%20of%20Variable%20Generation%20Task%20Force%20IVGT/Sub%20Teams/Probabilistic%20Techniques/IVGTF1-2.pdf.
[59] E. Ibanez, M. Milligan, *Comparing Resource Adequacy Metrics*, National Renewable Energy Laboratory, 13th International Workshop on Large-Scale Integration of Wind Power into Power Systems, Berlin, Germany, Nov. 11-13, 2014, https://www nrel.gov/docs/fy14osti/62847.pdf.
[60] *MacNeil Rebuttal*, line 681.
[61] *Id*. at lines 681-82.

runs can quantify varying levels of risk associated with the variations in demand, hydro, and thermal outage conditions, but don't account for variations in solar energy.

Q. Is MacNeil correct that it is inappropriate to use a gas proxy for capacity value?

A. No. MacNeil is incorrect in claiming that a new solar resource could only displace another solar resource.[62] Using a gas proxy for capacity value is appropriate. In my experience, the prevailing practice of valuing capacity is based upon a single benchmark unit. In the U.S., this benchmark unit is most often a combustion turbine, which has relatively low capital cost and relatively high variable cost. Units such as this are almost never economic if the utility requires substantial amounts of energy. However, this type of resource can be used to meet capacity requirements. This is why it is the most-used capacity cost proxy.

MacNeil describes the use of a simple cycle combustion turbine that is used to value the avoided capacity cost of a thermal resource.[63] This proxy unit has a capital cost of $88/kW-yr (in 2026 dollars). However, RMP only uses this value for a baseload unit.

MacNeil also argues that "capacity values are intended to be interchangeable building blocks for meeting planning reserve requirements…".[64] This statement does not square with the use of a combustion turbine as the capacity proxy for thermal generation, and the use of solar plus storage as a replacement for other solar. Further, in MacNeil's

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[62] *Id*. at lines 766-67.
[63] *Id*. at lines 765-66.
[64] *Id*. at lines 444-45.

description of PacifiCorp's Reliability Assessment, the proxy resource for a shortage appears to be a simple cycle combustion turbine, energy storage, or energy efficiency.[65]

Recognizing that peaking resources are most often used to value capacity, Vivint Solar proposes using the capacity cost of a new gas peaking resource, which is $77/kW-yr.[66]

Q. MacNeil criticizes your use of RMP demand in the calculation of CG avoided capacity, and says that all of PacifiCorp's load should have been included.[67] How do you respond?

A. The PacifiCorp system is divided into two separate balancing areas, linked by a relatively small transmission path via a third-party system. These two Balancing Authority Areas (BAAs), PacifiCorp West (PACW) and PacifiCorp East (PACE) are each required to meet NERC balancing standards. Given the nature of the split system, and the potential difficulty of accessing capacity across this third-party transmission link during critical time periods, it would be reasonable to separate capacity obligations, which is what I did.

Q. RMP criticizes the capacity carrying charge that you used in your analysis, stating that the current rate is less. How do you respond?

A. The 9.39% annual carrying charge I used was based upon the PacifiCorp 2018 Marginal Cost Study from California.[68] RMP states that the current value is 7.82%.[69]

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[65] *Id*. at lines 512-13.
[66] Vivint Solar, Inc., *Rebuttal Testimony of Christopher Worley*, July 15, 2020, lines 386-87.
[67] *MacNeil Rebuttal*, line 339-40.
[68] *Milligan Revised Affirmative*, lines 560-61 n. 42.
[69] *MacNeil Rebuttal*, line 835.

Q. RMP criticizes the capacity proxy used in your capacity valuation.[70] How do you respond?

A. The appropriate capacity proxy resource is the combustion turbine that is used by PacifiCorp, which has a cost of about $78.61/kW-yr in 2021 dollars. As I explain in my Revised Affirmative Testimony, in valuing capacity I intended to select a low-cost capacity resource, consistent with a least-cost planning process.[71] However, in performing my calculation I inadvertently used the cost of a duct-firing resource, with a cost of $316/kW ($29.67/kW-yr). A duct-firing resource is a lower-cost resource than a combustion turbine, but it is not a good proxy for calculating capacity.

Q. RMP says that your capacity calculations in future years did not account for weather or day of week. What is your response?

A. Weather is a common driver of both demand for electricity and solar generation. To the extent that time-varying profiles—hourly data for a year or more—are preserved, the weather is implicitly accounted for. I have run the analysis with a day-of-week adjustment and found that it increases the average capacity contribution from 27.65 to 29.50% of rated capacity, based upon the top 10% of load hours.

Q. Did you re-calculate the capacity value of CG solar exports using a revised capacity cost?

A. Yes.

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[70] *Id*. at lines 789-91, 801-12.
[71] *Milligan Revised Affirmative*, lines 549-51.

Q. How did the capacity value change?

A. Using the combustion turbine proxy resource from PacifiCorp and a day-of-week adjustment, the capacity value of CG solar increases to 3.43 cents/kWh, revised upward from 1.48 cents/kWh in my Revised Affirmative Testimony.[72]

Q. Returning to the issue of future uncertainty, how does the top 10% of load hours help mitigate this uncertainty?

A. To provide additional insights on the way this method works, I calculated the CG capacity factor for the top 10% load hours in 1% increments for Utah. The results appear in Figure 4.

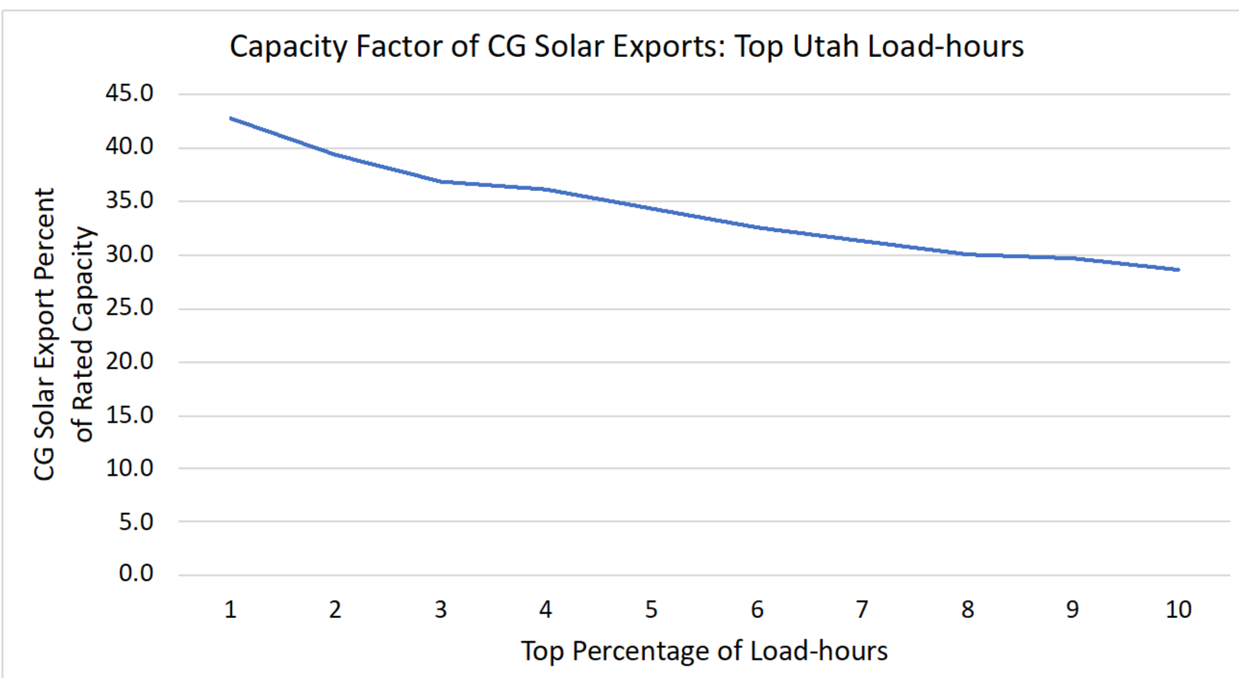

Figure 4. Alternative capacity factor proxies based upon aggregate PacifiCorp demand

[72] *Id*. at line 629.

Q. How do you interpret this graph?

A. All of the other proxies, based upon smaller load-hour windows around the peak, show higher CG capacity values than the 28.6% capacity factor over the top 10% of load hours. In MacNeil's Rebuttal Testimony, he states there are 278 hours that are identified as having a loss of load risk.[73] Although I do not challenge this assessment, the specific hours in which MacNeil identifies this risk is based upon a single year of data, and it is not clear how the interplay of hourly demand and CG generation will evolve in the future. The pattern of risks during the top 278 hours in future years will likely change, but will also likely occur at some point during peak or near-peak periods. The question is, which of the above aggregation of hours will encompass MacNeil's 278 hours of highest risk in the future? Applying specific LOLP weight will undoubtably improve the accuracy of the calculation *for 2019*; however, *future risks* of loss of load will depend upon the interplay of many variables that will differ from historical events. Comparing data from the graph in Figure 4, which shows declining capacity contributions as the number of top load-hours is increased, illustrates that using the top 10% of load hours results in a relatively conservative estimate of how CG can contribute to capacity requirements using a proxy method that has been shown to be reasonable in the way it matches a multi-year ELCC. Furthermore, broadening the number of hours from 278 to 876 hours allows for variations in the timing of *future* LOLP risk and includes "near-peak" periods that may have LOLP risk that results from

[73] *Milligan Rebuttal,* line 683.

changes in imports/exports, scheduled maintenance, hydro supply variations, and other factors that can result in LOLP risk that may emerge.[74]

Another aspect of this graph indirectly addresses the issue of declining capacity value as solar penetration increases. During the top 1% of load hours—88 hours—the capacity factor is 43%. As more hours are considered, the capacity factor declines. The graph shows a capacity factor of about 39% during the top 2% of load hours—about 175 hours. The top 3% of load hours represents about 263 hours of the year, and the graph shows about 37% contribution. I note that the number of hours in the top 3%—263 hours—is very close to MacNeil's 278 hours of highest risk.

Q. Please summarize your avoided capacity calculation.

A. Using a combustion turbine as a proxy resource, I calculated an avoided capacity cost of 3.43 cents/kWh. This compares to 1.48 cents/kWh in my Revised Affirmative Testimony.[75]

VI. Ancillary Services and Integration Costs

Q. MacNeil states that CG exports are not anticipated to be under company control.[76] Does that mean they cannot supply ancillary services?

A. Some ancillary services are provided automatically, as a result of smart inverter technology. These include reactive power and voltage support. As Vote Solar witness

[74] *Milligan Revised Affirmative*, line 508.
[75] *Id*. at line 629.
[76] *MacNeil Rebuttal*, lines 1052-53.

Curt Volkmann stated in his Rebuttal Testimony, smart inverters can mitigate voltage concerns on the distribution system, and can "reduce or eliminate the need for additional conventional voltage-regulating equipment."[77] Services such as automatic generation control or economic dispatch would require a control mechanism from the utility, and would be exercised by RMP if and when it is economic to do so. This would effectively supply the service for which CG is being assessed integration costs.

Q. Has RMP provided support for its proposed integration cost for CG solar?

A. No. I have not seen any support for RMP's proposed integration cost for CG solar.

VII. Carbon Emissions

Q. MacNeil states that using market prices to value CG means that all CG is sold in the market, therefore having no emission impact on RMP.[78] Is that correct?

A. Vote Solar did not assume that all—or any—CG would be sold. Vote Solar's studies presented to this Commission show that as a result of CG exports, RMP will have the opportunity to turn down emission producing resources. In my analysis the OFPC was used as a valuation metric. Some solar could potentially be sold at the prevailing OFPC, but at other times RMP could avoid entering into purchase transactions at the market hubs. If RMP reduces the output of a thermal resource as a

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[77] Vote Solar, *Rebuttal Testimony of Curt Volkmann*, July 15, 2020, lines 259-60.
[78] *MacNeil Rebuttal*, 1153-54.

result of CG solar exports, then there is an emission reduction. If instead the CG solar export is sold to a neighboring utility, it would likely reduce output from a neighboring thermal plant, which would also reduce emissions.

Q. RMP criticizes the use of average emission rates in the avoided emissions calculation.[79] How do you respond?

A. My estimate is based upon long-term emission reductions. While there are uncertainties around these estimates, they provide a reasonable long-term estimate in a system that will be changing substantially in the future. Furthermore, my blended emissions rates were adjusted so as to account for the various retirements described in the 2019 IRP.

VIII. SUMMARY OF RECOMMENDATIONS

Q. Please summarize your recommendations.

A. I recommend that the Commission adopt the use of the OFPC in the evaluation of avoided energy cost of CG solar. This price has been developed with the express purpose of estimating the future market value of a kWh of electricity. It is calculated for every market hub and every hour for the period covered by PacifiCorp in its IRP. RMP's representatives are on record stating that it is the best available price estimate. The OFPC accounts for the many changes in the configuration of the power system in

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[79] *Id*. at 1131-51.

the future, including resource mix and transmission improvements, both of which will likely have a profound influence on market prices in the future.

I recommend that the Commission adopt Vote Solar's avoided capacity cost of 3.43 cents/kWh, which is based upon the highest top 10% of load hours for CG solar.

I also recommend that the Commission recognize the value of carbon emissions in this case. Although this may not be a private cost that accrues to RMP, it is a public cost that must be borne by consumers, and by society as a whole.

Finally, I recommend that RMP's proposed integration costs be excluded from the determination of avoided energy costs of CG solar.

Q. **Does this conclude your surrebuttal testimony?**

A. Yes.

CERTIFICATE OF SERVICE

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

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