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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**

AFFIRMATIVE TESTIMONY OF MICHAEL MILLIGAN, PH.D.

ON BEHALF OF

VOTE SOLAR

March 3, 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 direct testimony?

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

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

A. I am principle 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. 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 provides a statement of my qualifications and experience.

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

A. No.

II. PURPOSE OF TESTIMONY

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

A. The purpose of my testimony is to quantify several aspects of the value of exported customer generation ("CG") on the Rocky Mountain Power ("RMP") system to support the overall valuation provided in the testimony of Vote Solar witness, Dr. Carolyn Berry. Specifically, I will address three categories of value: (i) Avoided Energy Costs; (ii) Avoided Generation Capacity Costs; and (iii) Avoided Emissions volume.

Currently, over 99% of customers with CG in RMP's Utah service territory have distributed generation ("DG") solar.[1] As a result, I focus my analysis of the value of CG exports on the characteristics of DG solar. It is my understanding that the compensation mechanism for exported CG that will be approved in this case will take effect in 2021.

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[1] Vote Solar, *Affirmative Testimony of Briana Kobor*, Section IV.

Accordingly, all of my results are provided 2021 dollars and cover the 20-year period 2021-2040. I focus on this time period because it provides an accurate representation of the value of CG commensurate with the minimum expected lifetime of DG solar.

The *first* value that I quantify in my testimony is the value of avoided energy costs associated with CG exports. When solar energy is generated at the customer's location and exported to the grid, that energy flows to the nearest load sink and offsets the amount of energy that needs to be provided by RMP. The reduction in electricity demand is matched by either a reduction in electricity produced by RMP or in an additional unit of energy that RMP can sell to a neighboring utility. My analysis examines the specific attributes of exported CG in RMP's Utah service territory to derive a value for avoided energy costs inclusive of avoided line losses.

The *second* value that I quantify is the avoided generation capacity cost. To the extent that CG exports are produced during times of system peak, the required capacity that RMP needs to acquire to serve its demand will decrease. In my testimony, I calculate the value of this avoided capacity need that results from CG exports.

Finally, I calculate avoided carbon dioxide emissions ("CO_2") that result from CG exports by examining the emissions profile of RMP's fossil-fuel powered fleet and how those resources may change over time.

The results of each of my analyses were provided to Dr. Berry who then provided the total assessment of the value of CG.

III. SUMMARY OF RECOMMENDATIONS

Q. Please provide a brief summary of your recommendations.

A. I recommend that the avoided cost results from my testimony be adopted in the valuation of CG exports to inform just and reasonable compensation that captures the value of this resource. I find that CG exports provide benefits to RMP in the form of avoided energy costs, avoided line losses, avoided generation capacity costs, and avoided carbon emissions.

As described in full detail in my testimony, I recommend the following values be incorporated into the value of CG analysis:

1. An avoided energy value of 3.65 c/kWh;
2. An avoided line loss value of 0.31 c/kWh;
3. An avoided generation capacity value of 1.60 c/kWh; and
4. Avoided carbon emissions based on my annual projections that average to 229,097 tons/year.

My lack of comments on RMP's affirmative testimony filed on February 3, 2020 should not be interpreted as acquiescence or agreement with RMP. 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 to this proceeding.

IV. AVOIDED ENERGY COSTS

Q. What drives energy costs for a utility such as RMP?

A. The cost of energy is driven primarily by fuel costs and maintenance costs. These costs are variable costs – they depend directly on the volume of electricity produced. Demand for electricity varies significantly from hour to hour, day to day, and even year to year. To ensure demand is met at all times, utilities, including RMP, utilize complex software and telecommunications systems so that the electric energy can be supplied reliably and at minimum cost. The computer software evaluates the suite of available resources – including their energy cost, physical characteristics, and capabilities – and develops a generation schedule for each resource that takes all of these items into account. This is generally referred to as a "least-cost dispatch" (also called "economic dispatch" because the solution is economic—the lowest-cost solution to meet demand) and is standard operating practice in the power system industry.

Figure 1 shows how demand generally varies throughout the day, with a representation of weekly demand on the lower side of the diagram.[2] At low levels of demand, the cost-minimization algorithm chooses the resource with the lowest marginal cost,[3] followed by the resource with the next-lowest marginal cost if needed. The process generally occurs at

[2] *See* Michael Milligan, Erik Ela, Jeff Hein, Thomas Schneider, Gregory Brinkman, and Paul Denholm, *Renewable Electricity Futures Study Volume 4: Exploration Bulk Electric Power Systems: Operations and Transmission Planning,* National Renewable Energy Laboratory, v. 4, p. 25-1, June 2012, https://www.nrel.gov/docs/fy12osti/52409-4.pdf.

[3] The resource with the lowest marginal cost is the cost of producing one additional MWh or GWh.

intervals of 5-minutes up to one hour throughout the day; PacifiCorp is a member of the Western Energy Imbalance Market, which carries out this dispatch process every five minutes.[4] At the time of peak demand, if all low-marginal-cost resources are already being dispatched, relatively expensive resources will need to be deployed. The economic dispatch model will, however, minimize total production cost by avoiding the use of these expensive resources whenever possible.[5] Minimizing production cost is also a general requirement imposed on utilities by state regulatory commissions.

The "least-cost" nature of the dispatch process guarantees that resources with zero or near-zero marginal cost are chosen before a more expensive resource is chosen. Examples of these low-cost resources include hydro power, wind power, and solar power. Although there are exceptional times when these resources may be curtailed, they are utilized whenever system balance and reliability can be maintained. Viewing Figure 1 in the context of economic dispatch, if a new inexpensive resource becomes available, it will displace the resource at the "top" of the stack as the displaced resource is the highest cost resource.[6]

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[4] Western Energy Imbalance Market, *About*, 2020, https://www.westerneim.com/Pages/About/default.aspx.
[5] For a short description of common power system models, see Erin Boyd, *Power Sector Modeling 101*, U.S. Department of Energy – Office of Energy Policy and Systems Analysis, https://www.energy.gov/sites/prod/files/2016/02/f30/EPSA_Power_Sector_Modeling_FINAL_021816_0.pdf.
[6] Michael Milligan, Erik Ela, Bri-Mathias Hodge, Brendan Kirby, Debra Lew, Charlton Clark, Jennifer DeCesaro, and Kevin Lynn, *Cost-Causation and Integration Cost Analysis for Variable Generation*, National Renewable Energy Laboratory, June 2011, https://www.nrel.gov/docs/fy11osti/51860.pdf; *see also, e.g.*, U.S. Energy Information Administration, *Electric generator dispatch depends on system demand and the relative cost of operation* (Aug. 17, 2012), https://www.eia.gov/todayinenergy/detail.php?id=7590.

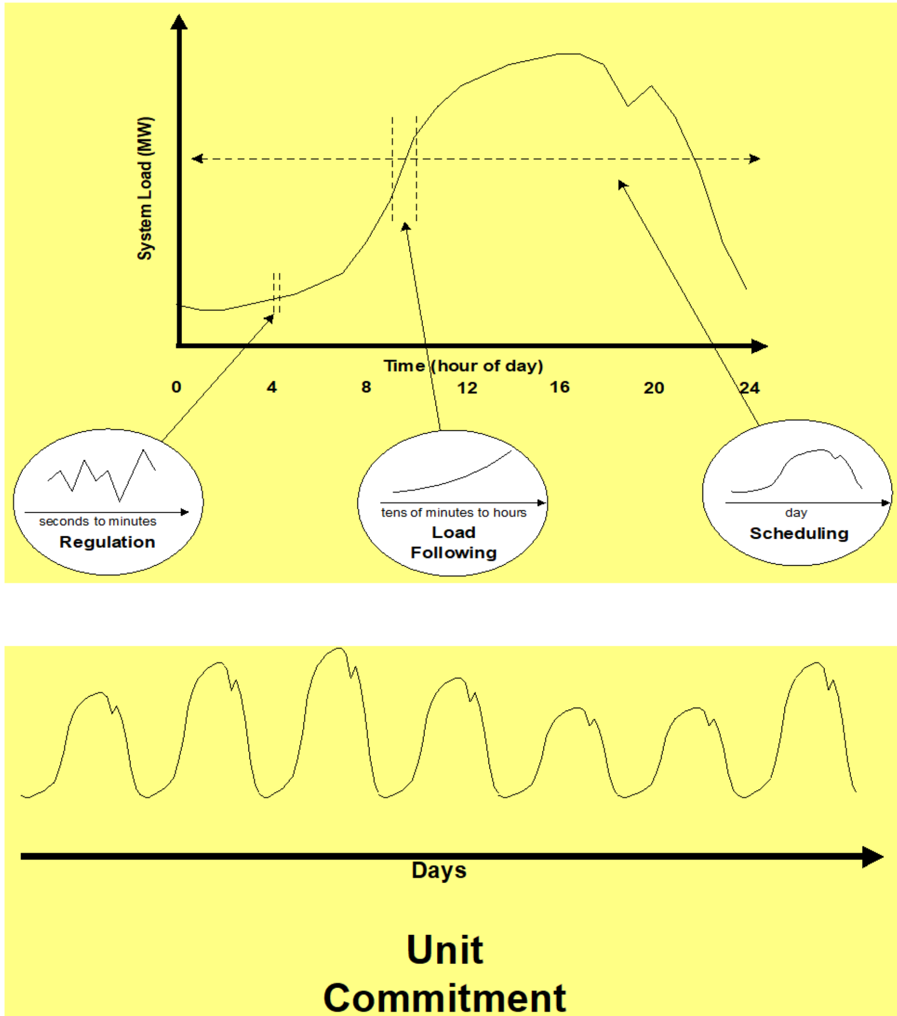

Figure 1. Sample daily and weekly electricity demand

The discussion above has particular relevance for the energy value of DG solar. Solar power, generated at a customer location on the distribution network, will reduce demand, which then reduces the need for electricity from the most expensive generator on the system. Thus, the value of the solar-generated energy is the cost of the energy from the most expensive resource. This concept is illustrated by a hypothetical supply curve from the U.S. Energy Information Administration in Figure 2. The supply curve shows that resources with low or zero marginal cost, such as solar energy, are dispatched first. As demand increases, higher-cost resources are deployed. Conversely, as demand falls, the operating cost falls as expensive units are taken off dispatch. Solar energy, whether connected to the transmission system or to the distribution system, will displace relatively high-cost resources on the supply curve.

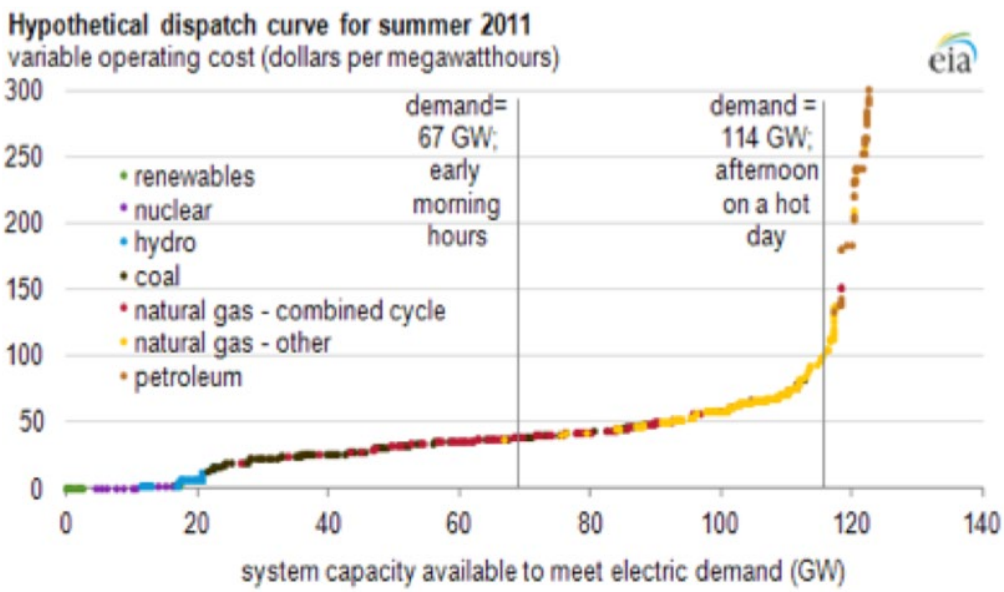

Figure 2. Example demand curve shows that renewables are dispatched first because of their low marginal cost[7]

The economic dispatch as described above does not consider constraints that may occur on the grid that prevent the least-cost dispatch from being realized. For example, the least-cost resource might be unavailable because it is behind a network constraint, which means there is insufficient transmission or distribution capacity to deliver the energy to the load center. In such situations, an alternative, more expensive resource may be needed to avoid the congested path, which can increase the cost of energy.

[7] U.S. Energy Information Administration, *Electric generator dispatch depends on system demand and the relative cost of operation* (Aug. 17, 2012), https://www.eia.gov/todayinenergy/detail.php?id=7590.

During extreme peak periods, the utility may need to deploy its most expensive resource (highest marginal cost resource) to meet demand. In some cases, it may be necessary to import electricity from a neighboring system during such a peak period. The value of energy in such a transaction is determined by a combination of the marginal cost of each of the two neighboring systems, along with potential network constraints. When a transaction is carried out, the price paid is a direct indicator of the value to both the buyer and seller.

In the U.S. Western Interconnection,[8] there are several large substations that are often used as electricity delivery points for market transactions between utilities. Utilities have well-developed trading frameworks in place at these market hubs that facilitate common market products.[9] Many utilities that trade in these hubs have a desire to forecast future market fundamentals—including detailed price forecasts for each trading hub covering time periods from the present to the future—so that they can plan how best to invest in new facilities to meet future demand. The trading price at any hub at a given time will depend upon the utilities' positions on their supply curve for the hour in question, the internal resources that are available and at what price, and what bids from other resource-owners are available, along with other information such as projected transmission congestion.

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[8] The Western Interconnection is described on the web site of the Western Electricity Coordinating Council ("WECC"). *The Western Interconnection,* Western Electricity Coordinating Council, https://www.wecc.org/epubs/StateOfTheInterconnection/Pages/The-Western-Interconnection.aspx.

[9] *See, e.g.*, S&P Global, *Methodology and specifications guide, North American Electricity*, p. 8, Feb. 2020, https://www.spglobal.com/platts/plattscontent/_assets/_files/en/our-methodology/methodology-specifications/na_power_method.pdf.

RMP participates in some of these markets, and it has developed a comprehensive price forecast for its key trading hubs, hourly by hub, through 2040. This price forecast is useful for evaluating avoided energy costs associated with exported CG in RMP's Utah service territory.

Q. How can CG result in avoided energy costs?

A. For every MWh of CG energy that is produced, the utility reduces its energy delivery requirement to its end-use customers by one MWh. Because power plants are operated according to cost-minimization principles, a low-cost or no-cost resource, such as CG, will cause a reduction in power and energy production for the utility. Since the power system must be in balance at all times according to rules set out by the NERC,[10] if the aggregate increase in CG is 100 MW over an hour that energy will appear as a reduction in demand on the distribution system and a commensurate amount of generation will be turned down for the hour. Therefore, a power system operator for a utility like RMP must decide which unit(s) to reduce so that there is no excess generation on the grid. In practicality, these decisions will be made by sophisticated software tools that are well equipped to handle fluctuations in demand (whether resulting from CG exports or other customer activities).

[10] NERC balancing standards are described in *Standard BAL-001-2 – Real Power Balancing Control Performance*, North American Electric Reliability Corporation, https://www nerc.com/pa/Stand/Reliability%20Standards/BAL-001-2.pdf. NERC's "Balancing and Frequency Control" technical document describes other aspects of the balancing standard including the equation for Area Control Error ("ACE") that shows the relationship between the level of generation, demand, frequency, imports, and exports. NERC Resources Subcommittee, *Balancing and Frequency Control*, North American Electric Reliability Corporation, Jan. 26, 2011, https://www.nerc.com/docs/oc/rs/NERC%20Balancing%20and%20Frequency%20Control%20040520111.pdf.

Alternatively, if there is an offer from another utility to purchase the excess energy made available by CG exports, then another resource in a different utility control area must reduce its power for the hour so that it can import the extra power and energy. In this scenario, RMP must therefore reduce its dispatch stack or find a buyer for the excess energy. In the first case, the value of displaced energy depends on which unit(s) are reduced and their marginal cost. If 100 MWh is displaced from a combined cycle gas unit with cost of $50/MWh, then the energy value of the CG is 100 MWh x $50/MWh = $5,000. In the second case, the avoided energy value of CG is determined in the market when the power is sold.

Q. How did you determine the appropriate value of avoided energy costs associated with exported CG?

A. I based avoided energy costs associated with exported CG on the market price for energy in RMP's Utah service territory. I based assumptions regarding market pricing on PacifiCorp's Official Forward Price Curve ("OFPC").[11] The OFPC is updated quarterly and represents PacifiCorp's "official quarterly outlook."[12] It is developed based on market forwards and fundamentals derived from a WECC-wide market model.[13] At the time of writing, the most recently available OFPC was developed September 30, 2019 and provided to Vote Solar under the confidentiality agreement in this Proceeding.[14].[15]

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[11] PacifiCorp is the parent company of RMP.
[12] *2019 Integrated Resources Plan*, PacifiCorp, Volume 1, p. 180, October 18, 2019, https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificorp/energy/integrated-resource-plan/2019_IRP_Volume_I.pdf.
[13] *Id.*
[14] Exhibit 2-MM, 1909 OFPC (CY2018_2041)_2019 10 10 (min 0.01)###_GLOBAL_csv, RMP's Responses to Vote Solar 9th Set Data Requests – Attach 9.2-1 (Feb. 6, 2020).

Q. Why is the market price a reasonable basis for the determination of avoided energy costs?

A. Market prices provide a measure of value, and the OFPC prices represent PacifiCorp's official assessment of the state of the power system—and the value of energy—at each hour and location from 2020-2040. At electricity trading hubs, any participating utility can offer electricity for sale or bid to purchase electricity, and as its needs change throughout the day, month, and year, a given utility may participate as a buyer during some periods, and a seller at other periods. There may be times at which the utility chooses not to participate.[16]

The decision of whether to buy or sell at the trading hub is primarily driven by economics and public service commission oversight that requires cost-effective operation of the power system, subject to reliability constraints. For example, in RMP's case, it may find that there are times during which there is electricity for sale at a price that is lower than what it could generate itself with its incumbent fleet of resources. At other times, RMP might find that it has excess generation (energy) that it could sell in the market, obtaining a higher price than the cost of generating that level of energy.

The other utilities that trade at these hubs face the same economic decision. Transactions are therefore characterized when a buyer, who has determined that its cost to purchase is less than its cost to generate (or purchase) from internal resources, finds it economical to

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[15] The OFPC does not include any assumptions for CO_2 pricing. *See supra* n.12 at 180. As described in more detail in Section VI, I developed a separate analysis of avoided emissions volume to support the avoided carbon costs discussed in the testimony of Dr. Berry.

[16] For an in-depth discussion of electricity markets, see Daniel S. Kirschen and Goran Strbac, *Fundamentals on Power System Economics* (2d ed. 2018).

buy power. At the same time, the seller has determined that it can generate energy and sell that energy at a cost that exceeds its marginal cost. The decisions of both buyers and sellers are driven by the relationship between their internal marginal cost and market prices. Specifically, sellers find that their marginal cost is less than the market price, and buyers find that their marginal cost exceeds the market price. Prices at electricity trading hubs represent the characteristics of operational cost for electricity that intersect when a transaction is executed. If RMP were to find that it must commit an additional generating unit to meet demand, but instead realizes that it can buy energy at a lower cost, the value of these additional MWhs is determined by the combined marginal cost curves of the buyer and seller.

The market prices that comprise the OFPC represent RMP's best effort to value electricity in the trading region. As described below, the OFPC accurately reflects relative scarcity accompanying high levels of demand. During these periods, the value of electricity is high because relatively high-cost resources must be dispatched to help meet demand. Neighboring systems may themselves be in similar situation, which is captured in the price forecasts. During off-peak times, the OFPC prices are lower, reflecting the relative lack of value of energy during those times. An economically rational utility will always compare its own internal cost of energy against the price it could pay in the market. If its own internal cost is high at the same time that a neighboring system is selling at a low price, then the economically rational utility will enter into a transaction that allows it to purchase energy at a price less than its own internal cost. In practicality, utilities may not always be able to act in an economically rational way as operational or system constraints may impact their ability to trade in the market. Thus, market prices provide a conservative estimate of the value of CG exports.

Q. Please describe the market hub data included in the OFPC as it relates to RMP's service territory.

A. The OFPC data that PacifiCorp developed represents hourly electricity prices at several relevant trading hubs, from 2020-2040. Because RMP is in the PacifiCorp East Balancing Area ("PACE"), several of these trading hubs that are connected to the PacifiCorp West Balancing Area ("PACW") may not be directly accessible to RMP. This can be seen on a map that was taken from the 2019 Integrated Resource Plan ("IRP") of PacifiCorp, shown below in Figure 3.

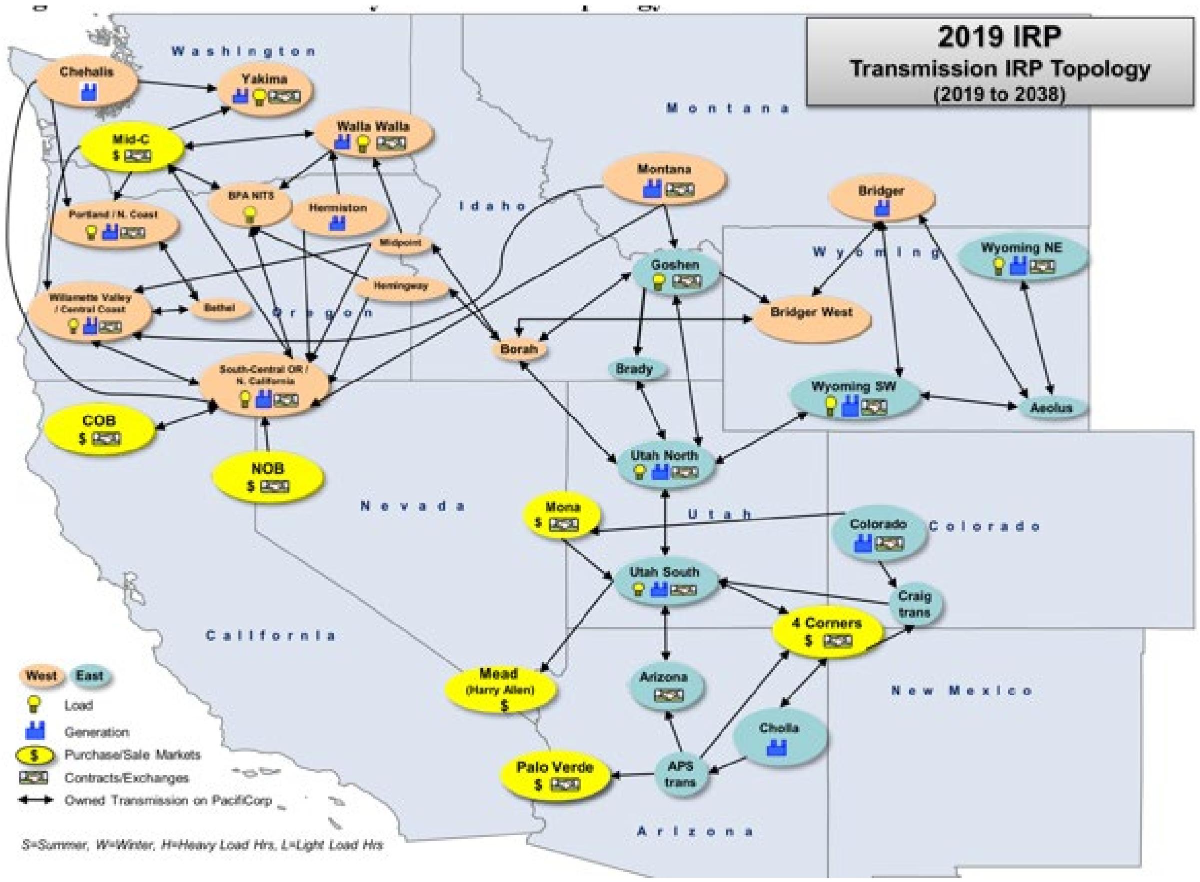

Figure 3. Transmission Map with Trading Hubs from the 2019 PacifiCorp IRP[17]

The map shows the bifurcation of the PacifiCorp system into two control areas (PACW and PACE)–otherwise known as balancing areas ("BA"). This bifurcation makes it difficult to move energy between the two BAs when there is insufficient transmission through the path at Borah. For the purposes of my analysis, I assumed that it is never possible to move energy from PACW to PACE, or conversely from PACE to PACW. This represents a conservative assumption because PacifiCorp can often move energy between control areas.

[17] *2019 Integrated Resources Plan*, PacifiCorp, Volume II, p. 279, Oct. 18, 2019, https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificorp/energy/integrated-resource-plan/2019_IRP_Volume_I.pdf.

Focusing on PACE, the map shows that Utah South has direct connections to trading hubs at Mead, Mona, and Four Corners. Depending on transmission loading and economics, Utah South may also have access to Palo Verde, and Utah North may, at times, have access to transmission through Borah, which could then allow access to other trading hubs. However, I assume that Utah South will primarily connect with its direct market hubs and flows between Utah North and South are generally unimpeded.

A. ANALYSIS OF OFPC

Q. How did you analyze the OFPC data?

A. For my analysis I used the OFPC data for the Mead, Mona, and Four Corners trading hubs. My analysis is divided into several sections:

1. Analysis of the OFPC data from the three trading hubs;
2. Combining the prices from all three hubs into a representative single market price assessment;
3. Calculating the value of solar, using the Vote Solar Load Research Study ("Vote Solar LRS") data; and
4. Further analysis of the pricing and solar-value results as described below.

Q. What do market prices look like at the three trading hubs based on the OFPC?

A. In order to get a general sense of pricing at the three hubs that are directly connected to RMP, I examined the OFPC data from 2021. This year was chosen because it is not far out in the future, and as such, is more likely representative of relative prices than periods that are far in the future, where forecasting errors are likely higher. The first step I took was to compare prices from the three hubs by first calculating the average, maximum, and standard deviation for each trading hub. The results appear in Figure 4. The graph indicates that the maximum price, average prices, and standard deviations from Four Corners and Mona are similar. Therefore, the two prices have similar variability properties and overall range. Mead has a lower maximum price, a higher average, and lower standard deviation. On balance, Mead has somewhat lower volatility, is higher on average, but has less range than the other two hubs.

[redacted]

Figure 4. Statistics for Three Trading Hubs, 2021[18]

[18] *See supra* n.14.

Next, I examined average price on a monthly basis for each of the trading hubs. A graphical comparison as shown in Figure 5 demonstrates that there are two key patterns. The first is illustrated by the common movement of Four Corners' prices and Mona prices, which follow a very similar pattern for the 12-month period. Mead's prices are different; significantly higher in winter months and somewhat lower in the peak months of July-September.

[redacted]

Figure 5. Average Monthly Prices[19]

I additionally calculated the average price for each hour of each month. This results in a block of 12x24 price averages and shows the average price by hour and month for each hub. The graphs appear in Appendix Fig. 1.[20] Each panel of the chart shows one of the trading hubs, and each cell of the table shows the average price at the relevant location

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[19] *Id.*
[20] *Id.*

for the month and hour that are indicated by the row label and the column header, respectively. To help visualize the relatively large quantity of data in each of the three tables, a "heat map" colorization was applied so that the highest prices are shown with a red background, moderate prices with a yellow background, and low prices with a blue background. Price levels that lie between these ranges are given appropriate color mixes.

Although the absolute prices levels differ—especially those of Mead—from each other, the overall price patterns are similar. Prices tend to peak in the late afternoon/early evening of July, August, and September. In time periods surrounding these periods, prices are moderate-to-high and are colored in some combination of orange and yellow. Moderately low prices appear in early morning hours, especially in July, August, and September, with more moderate prices appearing in the early morning hours of February, March, and occasionally January.

Q. How did you use this information?

A. Because these three trading hubs are directly accessible to RMP without wheeling energy across other systems, I averaged prices across the three hubs. The average price table appears in Appendix Fig. 2. I then calculated the 12x24 price block to facilitate comparison with Appendix Fig. 1.[21] The combined prices exhibit similar properties throughout the year, as can be seen by comparing Appendix Fig. 1 with Appendix Fig. 2. Although the characteristics of Mead prices are somewhat different than the other two, the overall shape of the 12x24 average prices are similar, and the average of the three hubs does not show significant changes from the individual hubs.

[21] *Id*.

To illustrate the wide range of prices, I developed a price duration curve as shown in Figure 6. Although it is difficult to ascertain precise point-values from the graph, it indicates that the price exceeded $[redacted]/MWh approximately [redacted] times in the 8,760 hours in the year. The price of $[redacted]/MWh was exceeded [redacted] times. From this information, I determined that the overall price level is low—below about $[redacted]/MWh about half of the time, and higher than $[redacted]/MWh about [redacted]% of the time. Very high prices—those above $[redacted]/MWh—occurred just over [redacted]% of the time.

[redacted]

Figure 6. Price Duration Curve for 3-hub Average Price[22]

[22] *Id*.

B. CALCULATING THE ENERGY VALUE OF CG EXPORTS

Q. How did you use the OFPC to calculate the avoided energy costs associated with CG exports?

A. To evaluate the avoided energy costs associated with CG exports, I applied the 3-hub average hourly OFPC price for 2021-2040 to the shape of CG exports. I obtained the CG export shape from the Vote Solar LRS, as shown in Exhibit 1-AJL. Figure 7 below provides the resulting average avoided energy costs in nominal dollars for the duration of the study period.

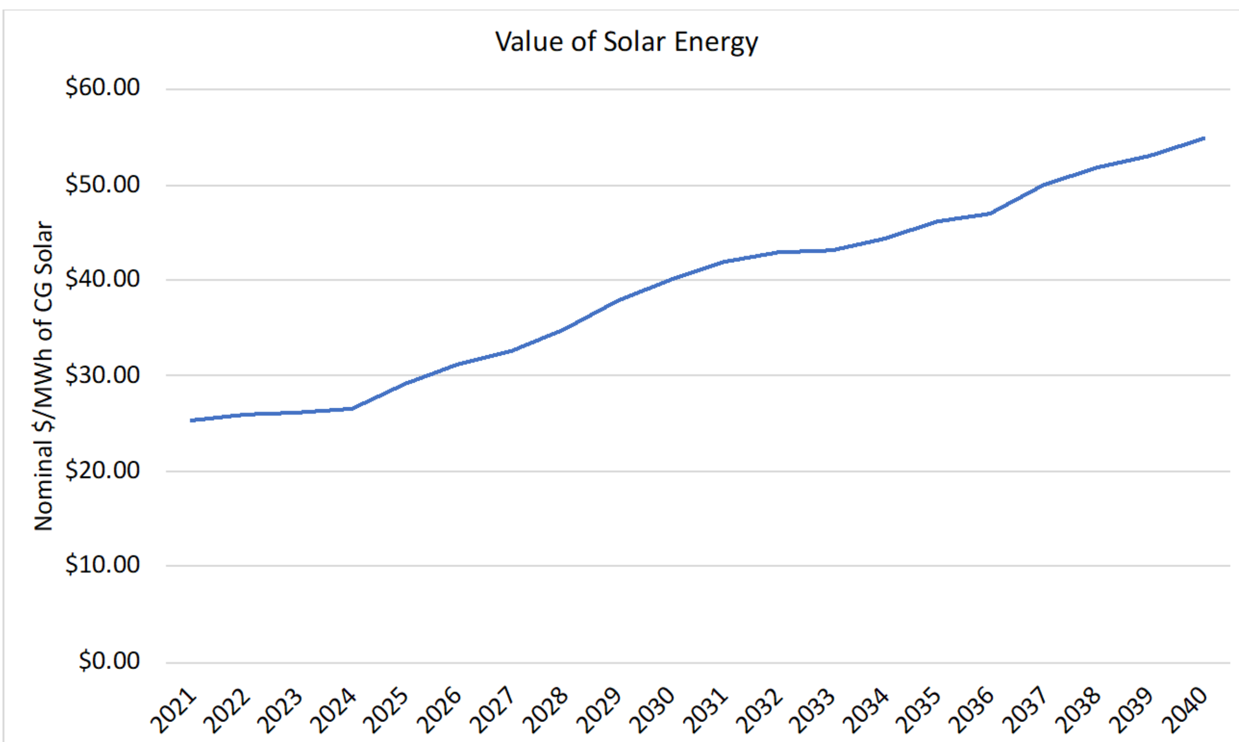

Figure 7. Value of Solar Energy

The avoided energy costs are a direct function of the price levels at the time that CG is exporting power. There is some overlap of CG exports with high prices, but that overlap is offset somewhat because, even though solar generation is high during peak periods of the summer, it produces power at a lower rate later in the day during the highest-price periods. This is shown in Appendix Fig. 3,[23] where the two temperature maps are stacked for ease of comparison. The value of solar is highest just after the high-price periods during the middle of the summer days.

Q. What did you conclude regarding avoided energy costs associated with CG exports?

A. To produce an estimate of avoided energy costs, I applied an inflation rate of 2.28% and a discount rate of 6.92% consistent with PacifiCorp's assumptions in its 2019 IRP.[24] The levelized value for the years 2021-2040 is 3.65 cents/kWh in 2021 dollars.

Q. Does your value of 3.65 cents/kWh include avoided line loss costs?

A. No. My value of 3.65 cents/kWh represents the avoided energy costs associated with CG exports at the location of the CG solar. For this amount of energy to be delivered to the distribution system, an additional amount of energy would be required to be generated and delivered to the customer's location. To capture the full avoided costs of energy, it is necessary to include avoided lines losses as well. Using data provided Mr. Curt Volkmann, I applied an energy loss percentage of 8.62% to calculate the additional avoided energy loss value of 0.31 cents/kWh.

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[23] *Id*.
[24] *Supra* n.12 at 179.

V. AVOIDED GENERATION CAPACITY COSTS

Q. What drives generation capacity costs for a utility?

A. Utility capacity costs are driven by the need to meet peak demand and satisfy reserve requirements. Utilities need to have sufficient capacity to meet peak demand with a planning reserve margin that protects against unforeseen operational problems or inaccurate peak demand forecasts. Capacity is measured by the expected availability of the resources on the system, after considering power plant performance characteristics that include capacity ratings and availability, which can be impacted by unexpected (forced) outages. In resource planning processes like PacifiCorp's the utility identifies future expected capacity needs and plans for additional resources as necessary.

Q. How can CG exports allow a utility to avoid generation capacity costs?

A. CG exports can allow a utility to avoid generation capacity costs if the exports provide capacity support for the utility. Generally, this means that the exports are available during peak periods. The extent to which CG can reduce capacity cost must be analyzed with appropriate calculations, as discussed in detail below.

Q. What information is required to evaluate the avoided generation capacity costs associated with CG?

A. There are two primary components required to evaluate the avoided capacity costs: (1) an estimate of the capacity value of the CG resource, measured in MW and (2) a cost of capacity on a $/kW or $/MW basis. I will address each in turn.

A. RESOURCE CAPACITY VALUE

Q. What is a resource capacity value?

A. The resource capacity value is a measure of the contribution of a resource to planning reserves. The basic algorithms to estimate resource capacity value have existed for many years, pre-dating the adoption of renewable resources. Every thermal plant has a rated capacity expressed in MW and also has a non-zero forced outage rate ("FOR"). This rate is a function of plant size and type, and generally older plants have higher FORs. The capacity value of any resource measures how it contributes to the overall planning reserve requirement, which is often expressed as a "loss-of-load" probability or mathematical expectation ("LOLP" or "LOLE," respectively). The most robust calculation of capacity value is based upon these LOLP models, and it is common to have a resource adequacy target of expected loss of load 1 day in every 10 years. The capacity contribution metric recommended by the North American Electric Reliability Corporation ("NERC") is the effective load carrying capability ("ELCC") metric or a similar variant that is based on loss-of-load probability or related metric.[25] The ELCC metric calculates the additional demand that can be served by the resource in question, returning long-term reliability to its level prior to adding the new resource.

Depending on the system characteristics, a thermal plant with nameplate capacity of 100 MW and FOR of 0.10 will generally have an ELCC of 90-92% of its rated capacity. Older plants may have FORs ranging up to 0.15 or even 0.20, with corresponding ELCCs

[25] 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.

of approximately 80-85% of rated capacity. Variable generation such as wind and solar have lower capacity contributions because of the variable nature of the wind or solar fuel.

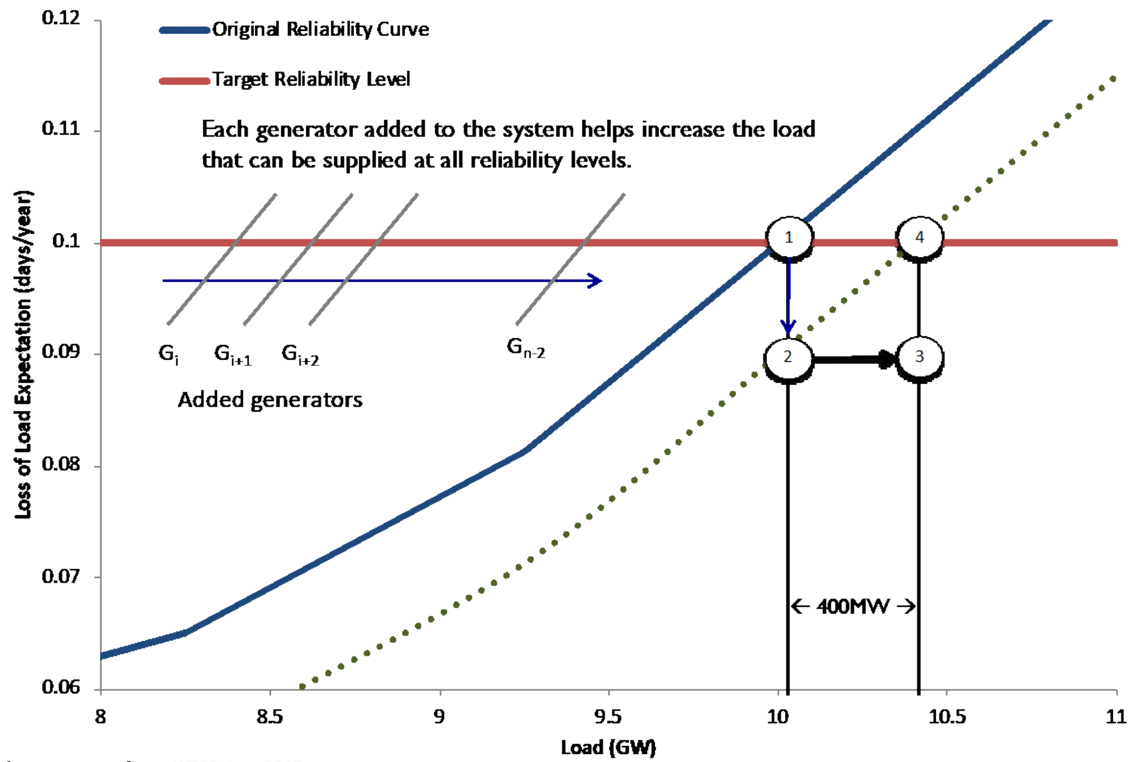
Q. Please describe the ELCC Method.

A. The ELCC method determines how much additional demand can be served by a new resource, holding reliability constant. Reliability is defined as a metric such as LOLP, LOLE, or expected unserved energy ("EUE," where "expected" refers to a probabilistic expected value), or similar metric. Much of the fundamental work on this was done by Roy Billinton and Ronald Allen.[26]

To use the ELCC method, a reliability target is chosen—a loss of load expectation of 0.1 day/year is common—and the base system is evaluated and adjusted so that it achieves the target. The new resource, such as solar generation, is added to the resource mix and the LOLE is recalculated. The new LOLE will have fallen because of the new resource. Then, demand is incremented until the LOLE increases to its original target. The amount of increased load that can be served while holding reliability constant is the ELCC of the new resource. Figure 8 is an adaptation of a graphic from the NERC 2011 report that illustrates the concept.[27] At point one, the system target of 0.1 day/year is achieved. A new resource is added, which shifts the reliability curve down and to the right. The new reliability level is depicted by point 2, and it is approximately 0.09 days/year. This is more reliable than the target, and because reliability is expensive, we gradually increase

[26] Roy Billinton and Ronald N. Allan, *Reliability Evaluation of Power Systems* (2d. ed. 1996).
[27] 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.

demand until the target reliability level is reached again, traveling through point 3 and arriving at point 4.



Milligan and Ibanez presentation to WECC, June 2015

Figure 8. Graphical depiction of ELCC

Q. Is ELCC Method always the best approach?

A. Even though the ELCC is the preferred method, it is a relatively complex calculation, not particularly transparent, and requires significant data and computing capability. Because of these factors, there are several methods that simplify or approximate ELCC. Some of these simplified methods have been benchmarked against ELCC so their ability to approximate ELCC is well understood.

Q. What information did you review to determine the best method to employ in this case?

A. In its 2019 IRP, PacifiCorp included a discussion and analysis of resource capacity value. In preparation for my testimony, I reviewed the method employed by PacifiCorp as well as the underlying data and analyses, which were provided in discovery.

Q. What method did PacifiCorp employ to determine the resource capacity value in its IRP?

A. According to the IRP, PacifiCorp utilized a LOLP model to calculate hourly LOLP value for its system by constructing a sample year with energy-not-served data (an output from an LOLP model), from June-September of 2030, and October-May from 2036. RMP then used these hourly LOLP values as weights, applied to the solar generation, to calculate the capacity value.[28]

Q. Is PacifiCorp's IRP method reasonable for adoption in this case?

A. No. The method used in the PacifiCorp IRP suffers from two related deficiencies: (1) it is based upon a method that has been shown to be less accurate than other simplified approximations to ELCC and (2) it is based solely on hourly LOLP values from two half-years that are unlikely to represent periods of long-term risk, which is what LOLP methods are intended to do.

[28] *See supra* n.12 at 397-405. Although wind and solar energy differ in some of their qualities, they both have variable and uncertain output, therefore it is reasonable to apply the results of the 1997 study to solar.

Q. Please describe how the PacifiCorp method compares to other approximation methods.

A. The method used by PacifiCorp has not been sufficiently analyzed, nor has it been validated as an accurate way to estimate ELCC. Interestingly, PacifiCorp's analysis refers to a paper that I co-authored in 1997. In the 1997 paper, my co-author and I compared 3 simplified ELCC approximation methods to the rigorous ELCC calculation itself: (1) top load hours; (2) LOLP indicators; and (3) LOLP-weighted (the same method as used by PacifiCorp). Figure 9 is reproduced from that paper. [29] The three methods were compared to a full ELCC calculation for wind energy in two ways.[30] The *first* was a simple counting metric: how many years, out of the 13 years studied did each method out-perform the other methods in replicating ELCC? This comparison is shown in the red bars in Figure 8. A higher score indicates better performance. The *second* comparison was based on the root mean square error ("RMSE") statistic,[31] which was calculated for the 13-year period. This comparison is shown in the green bars in Figure 8. For RMSE, a higher score is associated with poorer performance.

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[29] Michael Milligan and Brian Parsons, *A Comparison and Case Study of Capacity Credit Algorithms for Intermittent Generators*, https://www nrel.gov/docs/legosti/fy97/22591.pdf.
[30] *Id*.
[31] RMSE is a common metric that is used to calculate statistical errors. The calculation involves calculating the sum of the squares of the errors, and then taking the mean value of that sum.

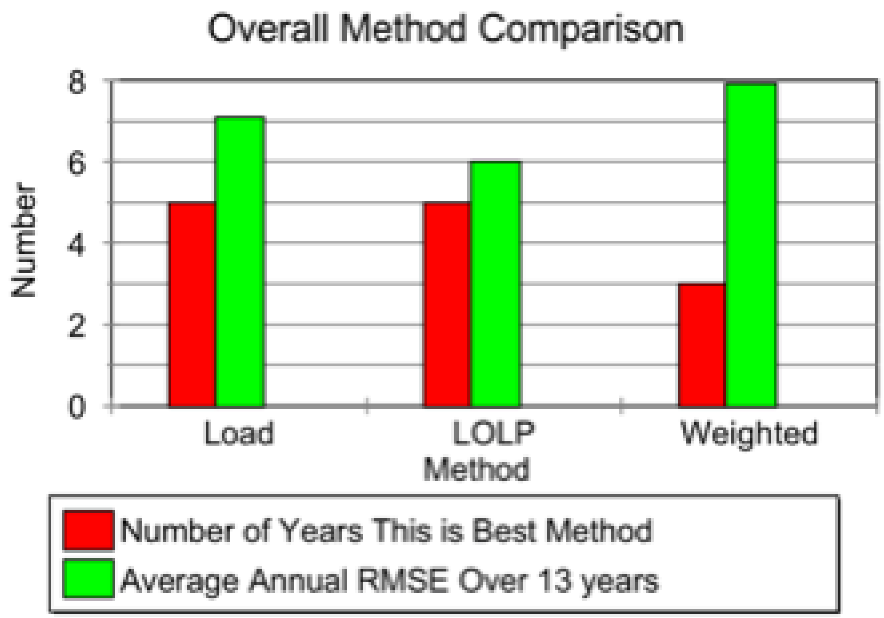

Figure 9. Comparison of capacity value methods, Milligan and Parsons, 1997

The "weighted" method that PacifiCorp used to evaluate the capacity contribution of renewables is shown to be the worst-performing metric among the ones studied in my 1997 paper. It outperformed the other methods in only 3 of the 13 years studied, and it had the highest RMSE of all the methods.

Q. What additional elements should be considered in the selection of a method to approximate ELCC?

A. There are other considerations beyond the accuracy of a method to match ELCC in a long-term planning study related to data availability. Because both demand and solar generation are clearly influenced by the weather, a single year of data will not represent the long-term performance of the resource. As described by NERC,[32] multiple years of

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[32] North American Electric Reliability Corporation, *Methods to Model and Calculate Capacity Contributions of Variable Generation for Resource Adequacy Planning*, Mar. 2011,

demand and renewables data should be used to ascertain the long-term level of resource adequacy that wind and solar energy can provide. Section 2.3 of the NERC report focuses on inter-annual variability and shows how the capacity value is sensitive to annual variations.

With 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. Generally, utilities are well aware of periods of time when there are risks of insufficient resources, and methods such as the "Load" method in my 1997 paper are the preferred approach for capturing long-term capacity value when data is limited, as it is in this case. It is extremely unlikely that RMP's hourly LOLP results will ever be replicated in a different year. In the absence of multiple years of renewable data, a more robust estimate of capacity value is necessary for long-term planning documents, such as an IRP.

Q. Do you recommend that RMP's IRP method be used in the determination of the resource capacity value associated with CG in this case?

A. No. I don't recommend the RMP method for any long-term planning use because of the concerns described above: (1) it has not been carefully and successfully compared to ELCC and long-term capacity value and (2) there are better methods.

Q. What method do you recommend be adopted for determination of the resource capacity value?

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https://www.nerc.com/comm/PC/Integration%20of%20Variable%20Generation%20Task%20Force%20IVGT/Sub%20Teams/Probabilistic%20Techniques/IVGTF1-2.pdf.

A. Ideally, a full ELCC analysis would be conducted, taking into account multiple years of time-coincident demand, because solar, wind, and hydro data are each driven by weather, which rarely if ever repeats itself. I discussed this issue in a recent presentation[33] and it is discussed in the NERC document.[34] Because PacifiCorp's data does not allow for the ideal calculation, the next-best approach must be adopted.

I recommend that resource capacity value be developed based on the "Load" method from my 1997 paper.[35] This method is often called the "capacity factor" method and is similar to a method utilized for many years by the PJM Regional Transmission Organization.[36] The capacity factor method utilizes a range of hours based upon the annual peak demand to determine the performance of algorithms that use the top 1%, 2%, through to the top 30% of load hours. In my judgment, based upon decades of researching and publishing on the subject, a capacity factor method that examines 10% of the top load hours will provide an adequate approximation of ELCC. In situations where multiple years of demand and production data are not available, such as this, the capacity factor method will provide a more robust analysis for resource capacity value than PacifiCorp's LOLP-based method.

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[33] Michael Milligan, *Building the Power Grid of the Future: Resource Adequacy Issues*, Presentation to Minnesota Clean Energy Advocates, Oct. 25, 2019, http://www.milligangridsolutions.com/MCEA%20Symposium%202019.pdf.

[34] 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.

[35] Michael Milligan and Brian Parsons*, A Comparison and Case Study of Capacity Credit Algorithms for Intermittent Generators,* National Renewable Energy Laboratory, Mar. 1997, https://www.nrel.gov/docs/legosti/fy97/22591.pdf.

[36] M. Milligan and K. Porter, *Determining the Capacity Value of Wind: An Updated Survey of Methods and Implementation*, National Renewable Energy Laboratory, p. 12–14, June 2008, https://www.nrel.gov/docs/fy08osti/43433.pdf.

Q. Can you elaborate why PacifiCorp's LOLP-based method is less robust?

A. LOLP-based methods are dependent upon finding periods of relatively high risk. The focus is the risk of having insufficient generation. Over a multiple-year period, weather can vary substantially. Because weather is an important driver for demand patterns along with renewable energy generation patterns, a period of LOLP risk in one year does not necessarily translate to LOLP risk at the same time(s) in another year. Therefore, employing a precise set of equations to a specific year of data may not capture the long-term risk patterns. The risk of LOLP has generally been shown to occur during high-demand periods, although other factors can contribute, such as maintenance schedules and off-system imports and exports.[37]

To illustrate, I used a 10-year subset of the load data provided by RMP in discovery[38] to show periods of potential LOLP risk throughout the 10-year period starting with 2021. I then calculated the MW demand of the top 10% of load-hours, or 876 hours of the year. I tabulated the periods of time that demand is in the top 10% of load hours. This captures potential time periods during which RMP could potentially be at LOLP risk. A graphical depiction of the monthly results appears in Figure 10.

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[37] 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.

[38] Exhibit 3-MM, 20190916 data disks/Confidential Attachments 6.10-1/Data Disk 2/Data Disk 2_CONF/Assumptions + Inputs/ Load,CONF/Base Loads (Net of PG).csv, RMP's Responses to Vote Solar 6th Set Data Requests – Attach 6.10-1 (Aug. 26, 2019).

[redacted]

Figure 10. Periods of high-demand that could put system at LOLP risk

As shown in the figure, periods of high demand occur primarily during the peak months of July and August, but lesser peak periods can also occur in May, June, and September. PacifiCorp relied on a single-year assessment of LOLP, but as demonstrated in Figure 10, LOLP-risk periods can vary year-to-year. When inter-annual variations are considered more fully, the periods of LOLP risk will change from year to year.[39] Therefore, PacifiCorp's method utilizing a precise calculation, but based upon limited data, is likely to miss periods of LOLP risk in a long-term planning study.

Q. What method do you recommend be adopted for determination of the resource capacity value?

A. For my assessment of the capacity value of solar for RMP, I used the capacity factor method including the top 10% of load hours as an input. I then used the solar energy production in those hours to calculate the capacity factor—the ratio of the mean to

[39] Other analyses have found a much larger impact when multiple years of actual data are considered. Consider this quote: "Analysis that was undertaken for the California Energy Commission found that during an unusually late, hot summer period when many units were taken out of service for scheduled maintenance, the hourly LOLP in late September was nearly as high as during the peak summer period. Situations like this can result in a lack of recognition of the exposure of the power supply to potentially high levels of risk…." *Supra* n.36 at 8–9.

the maximum. This method is preferred in instances, such as this, where data is limited and has been shown to reliably approximate ELCC.[40]

Using this method, I found the capacity value of CG exports averages 29.51% of the rated installed capacity. This was calculated for each of the years 2021-2030, and varied slightly from year to year, from 28.53% to 30.39%. For 2038-2040, when demand data was unavailable, I used the average of 2021-2037, which is 29.51% of rated capacity.

B. COST OF CAPACITY

Q. What is the cost of capacity in the context of avoided generation costs?

A. The cost of capacity is typically evaluated based upon the cost of a peaking resource, which could be a combustion turbine, aeroderivative generator, or reciprocating engines. Regardless of the specific technology used, the capacity resource selection attempts to isolate the contribution of capacity from the contribution of energy or other ancillary services. Peaking plants typically have a low cost in terms of \$/kW, but often have high energy costs. Due to these characteristics, peaking plants are commonly used in the power system industry as proxy resources in the evaluation of capacity.

Q. What information did you review to determine the appropriate cost of capacity to employ in your analysis?

A. I consulted the 2019 IRP, Table 6.1, which showed costs of options for RMP's preferred portfolio of resources.[41] Because my method calls for a capacity resource, I

[40] Michael Milligan and Brian Parsons, *A Comparison and Case Study of Capacity Credit Algorithms for Intermittent Generators,* National Renewable Energy Laboratory, Mar. 1997, https://www.nrel.gov/docs/legosti/fy97/22591.pdf.

selected a low-cost capacity resource based on its combined base capital cost and fixed O&M cost.

Q. Which resource do you recommend be considered in the analysis of avoided generation capacity costs of CG?

A. I selected the CCCT Dry "J/HA.01", DF, 2x1, ISO resource because it is a low-cost capacity resource, consistent with a least-cost planning process and consistent with the objective of calculating an avoided capacity cost for CG. The net capacity of this resource is listed at 126 MW, with base capital cost of $316/kW, fixed O&M of $4.05/kW-yr, with a 40-year design life.

C. CALCULATION OF AVOIDED GENERATION CAPACITY COST

Q. How did you calculate the avoided generation capacity cost associated with CG exports in RMP's Utah service territory?

A. I employed several assumptions to derive a levelized c/kWh rate for avoided generation capacity costs associated with CG exports based on the above-described findings for resource capacity value and generation capacity cost. To conduct the calculation, I adopted a 9.39% carrying charge to convert the capital cost to an annual $/kW-year.[42] I applied my findings that solar exports have an average 29.51% resource capacity value to the resulting annualized costs to derive the avoidable capacity value. In order to incorporate the effect of avoided line losses, I adopted a line loss factor of

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[41] *Supra* n.12 at Table 6.1.

[42] I selected the 9.39% carrying charge based on PacifiCorp's 20-year Generation Annual Economic Carrying Charge from a 2018 Marginal Cost Study filed in California. PacifiCorp, *Exhibit Accompanying Direct Testimony of Robert M. Meredith Marginal Cost of Service Study*, Public Utilities Commission of the State of California, Docket No. 18-04-, p. 42, Apr. 2018.

1.09080 as recommended by Mr. Volkmann. Finally, I adopted PacifiCorp's inflation rate of 2.28% and discount rate of 6.92% and find that the levelized value of the CG solar is $16.00/MWh of the solar resource, or 1.60 cents/kWh.

VI. AVOIDED CARBON EMISSIONS

Q. How does CG allow the utility to avoid carbon emissions?

A. Because solar energy has a marginal cost of $0/MWh, it is always preferred in the dispatch stack, as discussed previously in this testimony in Section IV. The process of determining the dispatch stack—the combination of resources' deployed capacity to meet demand—is a complex economic optimization that chooses the resource mix based upon a least-cost dispatch, subject to a variety of physical and reliability constraints. Because the marginal cost of solar is lower than any thermal resource, it will always be fully deployed unless some constraint on the power system requires an uneconomic dispatch, which raises operational costs of the power system. Distributed solar is not subject to the usual economic dispatch performed by power system operators, but it has the same impact on the dispatch stack. For every MW of solar power at a given time, one less MW of thermal generation is needed, and therefore less fuel burn is required to meet demand; thereby, reducing emissions. The specific emission reduction is a complex calculation, and the level of emission reduction per MWh of solar generation can vary based upon system conditions.

Q. What source of information did you use to evaluate the avoided carbon emissions associated with CG exports in RMP's Utah service territory?

A. To evaluate the avoided carbon emissions associated with CG exports, I developed a blended emissions rate based on actual emissions data from the U.S. Environmental Protection Agency ("EPA") and the U.S. Energy Information Administration.[43] This data includes the annual energy generation from each thermal power plant in PACE, measured both in electrical energy (kWh) and fuel (BTU – British Thermal Units, a measure of the energy content in fuels). The data set also contains emission information for several pollutants, including carbon dioxide (CO_2). Data on power plant emissions is specific to each power plant, and I utilized data from 2017 and 2018 to construct average emission rates for RMP.[44] Before calculating the emissions associated with RMP, I pro-rated RMP's ownership rate for all jointly-owned plants so that my calculations would apply only to RMP. Because the 2019 IRP contains many coal plant retirements, this average emission rate will change as plants retire and can either result in the increase or the decrease of average emissions per unit of energy, depending on the relationship of the retired plants' emission rates compared to the average. To account for this, I relied upon the Preferred Portfolio P-45CNW as described in the 2019 IRP.[45] Each year in which there was a thermal plant retirement (or multiple retirements), I recalculated the emissions rate accordingly.

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[43] *Power Plant Data Highlights*, U.S. Environmental Protection Agency, https://www.epa.gov/airmarkets/power-plant-data-highlights; *2017 National Emissions Inventory (NEI Data)*, U.S. Environmental Protection Agency (Feb. 2020), https://www.epa.gov/air-emissions-inventories/2017-national-emissions-inventory-nei-data.

[44] Emissions and production data from Naughton were not used because it appeared incorrect or incomplete in the EPA/EIA data.

[45] *Supra* n.12 at 279.

This analysis takes into account that CG exports will displace thermal generation and incorporates coal retirements based on expectations set forth in the IRP. The only cases in which CG exports would replace another renewable is if the system is not planned for flexibility. Renewable curtailment generally occurs because thermal units are not flexible enough to respond to changing net demand. PacifiCorp has demonstrated a keen interest, backed by significant analysis, to ensure their system will have the needed flexibility.[46]

Q. How did you calculate avoided carbon emissions reductions?

A. Using the average carbon emission rate for each year, I calculated carbon emission reductions based the CG export profile provided by Dr. Lee in Exhibit 1-AJL. Because of losses, one MWh of energy that is generated on the distribution system requires more than one MWh of energy generated at a central power plant, I utilized the same energy loss factor of 8.86% to calculate avoided carbon as used to calculate the avoided energy in my earlier testimony based on the recommendation of Mr. Volkmann. The annual results for the CG-related reductions in CO_2, are shown in Figure 11 where one can discern a downward trend in the annual emissions reduction, caused by the relatively early retirements of high-emission units. This causes the remaining operating thermal fleet to have lower emissions than before, reducing the emission benefits from solar energy.

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[46] For example, Appendix F of the 2019 IRP is a study of flexibility. *See supra* n.12 at 77.

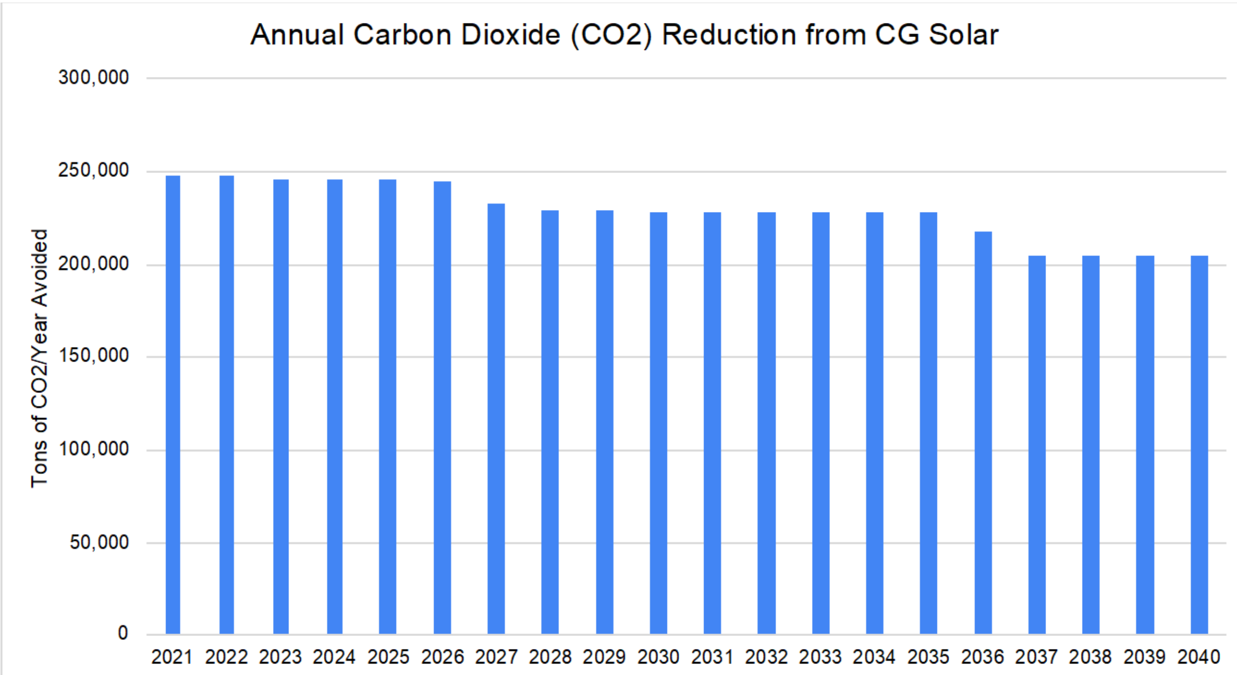


Figure 11. Emission reductions

Q. How was this information used in Vote Solar's Value of CG analysis?

A. I provided Dr. Berry with data on the annual carbon emissions avoided by CG over the study period 2021-2040. It is my understanding that Dr. Berry has used this information to derive values associated with avoided carbon emissions.

VII. SUMMARY OF RECOMMENDATIONS

Q. Please summarize your recommendations.

A. Based upon my findings, I recommend that the following levelized avoided costs be adopted in this proceeding:

1. An avoided energy value of 3.65 c/kWh;

2. An avoided line loss value of 0.31 c/kWh;

3. An avoided generation capacity value of 1.60 c/kWh; and

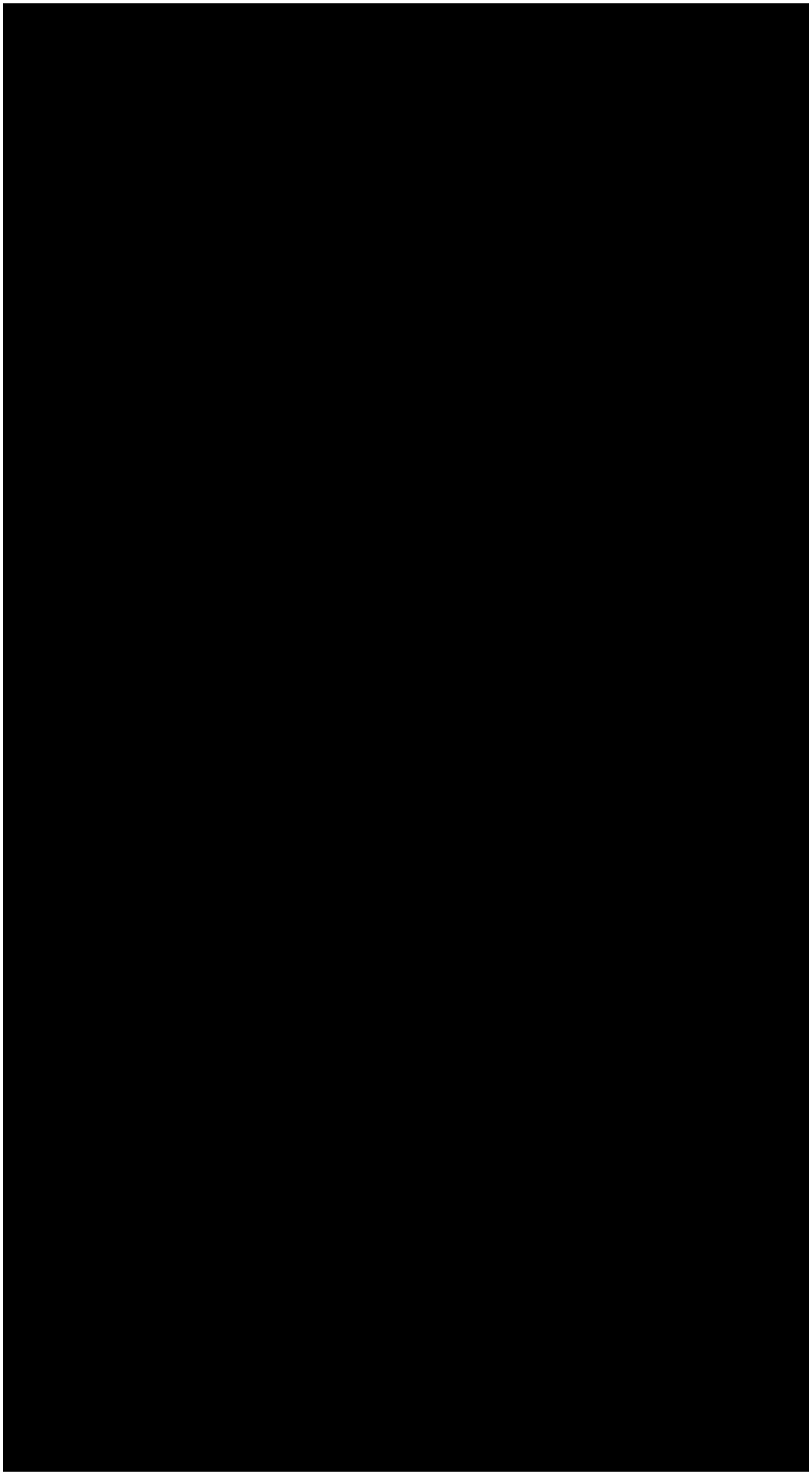
4. Avoided carbon emissions based on my annual projections that average to 229,097 tons/year.

Q. Does this conclude your testimony?

A. Yes.

VIII. APPENDICES

Appendices to follow on next page.



Appendix Fig. 1. Comparison of 12x24 price blocks

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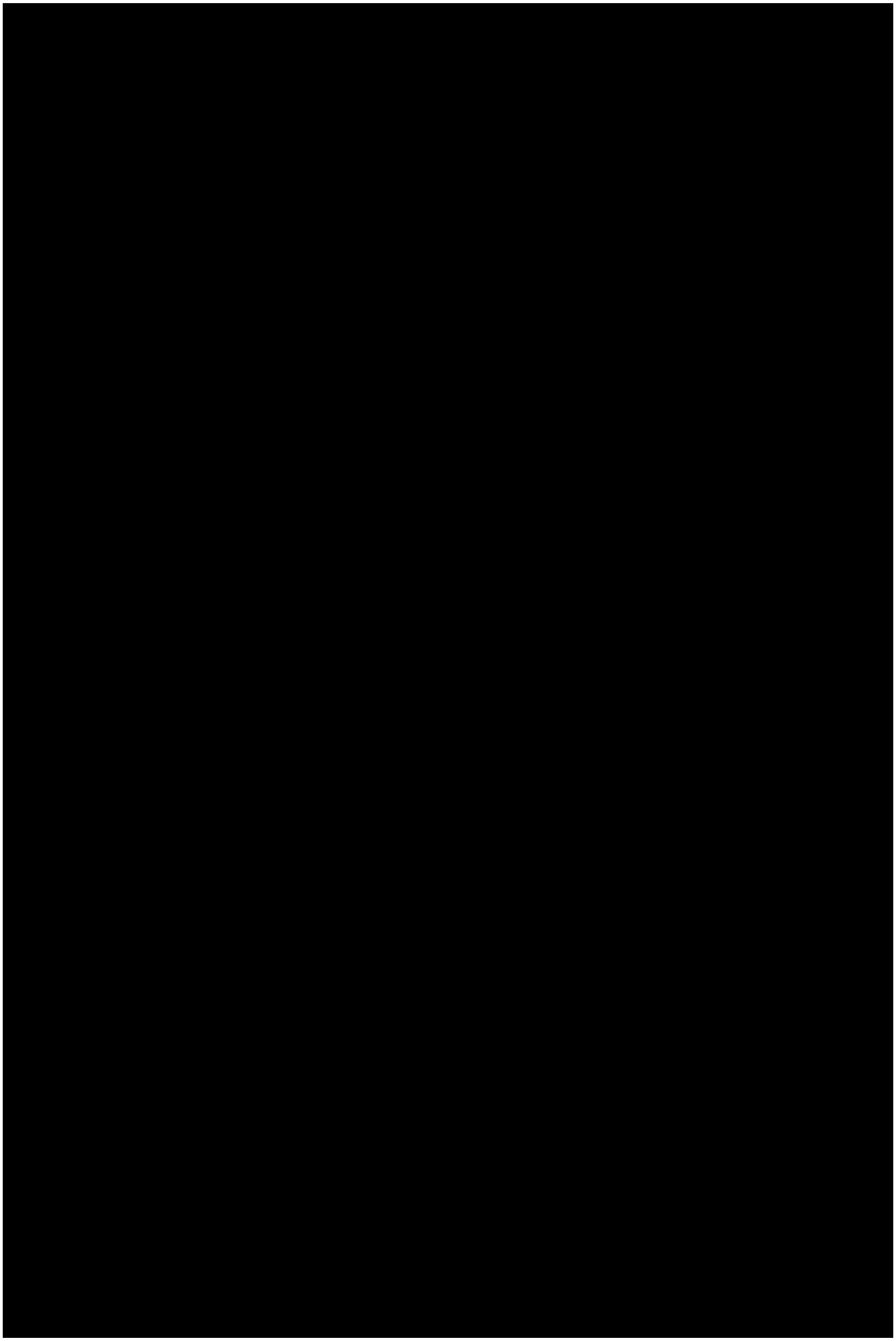

Appendix Fig. 3. 12x24 Value of Solar Energy and Average 3-hub Prices

CERTIFICATE OF SERVICE

I hereby certify that on this 3rd day of March, 2020 a true and correct copy of the foregoing was served by email upon the following:

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