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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**

REVISED AFFIRMATIVE TESTIMONY OF SPENCER S. YANG, PH.D.

ON BEHALF OF

VOTE SOLAR

May 8, 2020

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I. INTRODUCTION

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

A. My name is Spencer S. Yang. I am a Principal with Bates White, LLC. My business address is 2001 K Street NW, North Building, Suite 500, Washington, DC 20006.

Q. Please summarize your educational and professional background.

A. I received a Ph.D. in high energy physics from Columbia University in 1996. From 1996 to 2003, I was employed by the California Institute of Technology as a postdoctoral scholar, senior postdoctoral scholar, and then staff scientist in nuclear and high energy physics, and was a visiting scholar at Stanford University. Since 2003, I have served as a Principal with Bates White, LLC. During this time period, I have performed engineering, transmission, reliability, interconnection, renewable energy, value of solar, qualified facility ("QF"), Public Utility Regulatory Policies Act ("PURPA"), power purchase agreement, power flow, production cost, and market power analyses, and I have submitted expert testimony before the Federal Energy Regulatory Commission ("FERC") and in state regulatory proceedings in Maryland, Oregon, Texas, and Virginia in connection with, *inter alia*, the Exelon–Constellation merger, solar QF interconnection, Houston Import Project, and certificates of public convenience and necessity to construct a 500-kV transmission line; and civil courts in Mississippi and Texas. My curriculum vitae is attached as Exhibit 1-SSY.

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

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

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to provide input for valuing Customer Generation ("CG") exports in Rocky Mountain Power's ("RMP" or the "Company") service territory. [1] Specifically, my testimony is focused on quantifying avoided transmission and distribution ("T&D") capacity costs. In the instant case, RMP assigns zero values for avoided T&D and most of the value categories. My lack of comments on each of RMP's zero value components or the remainder of its affirmative testimony 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 in this proceeding.

[1] My analysis is based on Distributed Generation ("DG") solar. DG solar is comprised of small-scale photovoltaic facilities installed behind-the-meter, typically at residential rooftop or commercial sites. Behind-the-meter refers to a generating facility installed on the customer's side of the retail meter (i.e., "behind" the utility's billing meter) that serve all or part of the customer's retail load with generated energy. I understand that this proceeding concerns the determination of a just and reasonable export compensation for electricity generated by CG that includes technologies other than DG solar such as fuel cell. As of March 31, 2019, over 99% of CG (in kW) under Rate Schedule Nos. 135 and 136 is made up of DG solar. *See* Rocky Mountain Power. *Rocky Mountain Power's Customer Owned Generation and Net Metering Report and Attachment A for the Period April 1, 2018 through March 31, 2019*, Docket No: 19-035-29, Attachment A-Revised 2018 Customer Generation Report, August 15, 2019 https://psc.utah.gov/2019/07/01/docket-no-19-035-29/. The *de minimis* amount of non-DG solar technologies included in the CG class does not change my overall findings based on DG solar. I use CG and DG solar interchangeably in my testimony, unless otherwise specified.

Q. Please briefly describe how the balance of your testimony is organized.

A. In Section II, I provide a summary of my conclusions. In Section III, I describe the appropriate methodologies and calculations of avoided transmission capacity costs (Section III.A), avoided distribution capacity costs (Section III.B), and T&D losses avoided by CG exports (Section III.C). In section IV, I summarize the results of my avoided T&D capacity and loss benefits attributable to CG exports. Finally, in Section V, I provide a summary of my conclusions and recommendations.

II. SUMMARY OF CONCLUSIONS

Q. What are your principal conclusions?

A. I conclude that the value of avoided T&D capacity costs due to CG exports in RMP's service area is at least 2.02 cents/kWh, as shown in Table 1 below. These values are expressed in 2021 dollars and are based on the "levelized"[2] avoided costs of T&D capacity attributable to CG exports for the study period 2021–2040.

Table 1: Value of Avoided T&D Capacity Costs (2021 cents/kWh)[3]

Value Category	Value in 2021 cents/kWh
Avoided T Value	1.34
Avoided D Value	0.52
Avoided T&D Value	1.86

Q. How can CG exports avoid T&D capacity costs?

A. Utilities plan their T&D systems to reliably meet the current and future growth of peak demands. The CG consumed on site reduces loads on the utility T&D system, thus avoiding the need for load-related T&D investments. The remaining CG production exported to the grid (about 58% of the total CG production)[4] is likely to be consumed by the CG customer's neighbors, thus reducing loads on the upstream portions of the distribution system and the

[2] A standard practice of "levelization" concerns a way to reduce the annual stream of numbers over multi-year periods to a *single number*. Levelization generally employs discounting for the time value using a discount factor, which provides greater weight to values during the early years of a given time period and less weight to values at the tail end. *See* Section III.B below for more details on the levelization process.
[3] The new export compensation determined as a result of this proceeding is going into effect in 2021.
[4] Vote Solar, *Revised Affirmative Testimony of Albert J. Lee*, *Ph.D.*, Exhibit 1-AJL-REVISED.

higher voltage transmission system. In addition, CG exports can also defer or eliminate the need for new T&D capacity investments by reducing T&D losses.

Q. What are T&D losses?

A. All electricity generated from a source (point of generation) must be delivered through the transmission system and then distributed to a sink (point of consumption) through the distribution system, as illustrated in Figure 1 below.[5] T&D losses refer to the reduction in electricity occurring between the points of generation and consumption. The U.S. Energy Information Administration estimates that, on average, about 5% of the electricity that is transmitted and distributed annually in the United States is lost in the T&D system.[6] To the extent that an hourly profile of CG exports is more highly correlated with the on-peak hours, the avoided marginal loss rate due to CG exports can be much higher than the average loss rate. This is because increases in time-varying resistive losses are proportional to the square of the current.[7] Since marginal losses increase with square of the current (load), marginal losses are considerably higher during peak load periods than off-peak times.[8]

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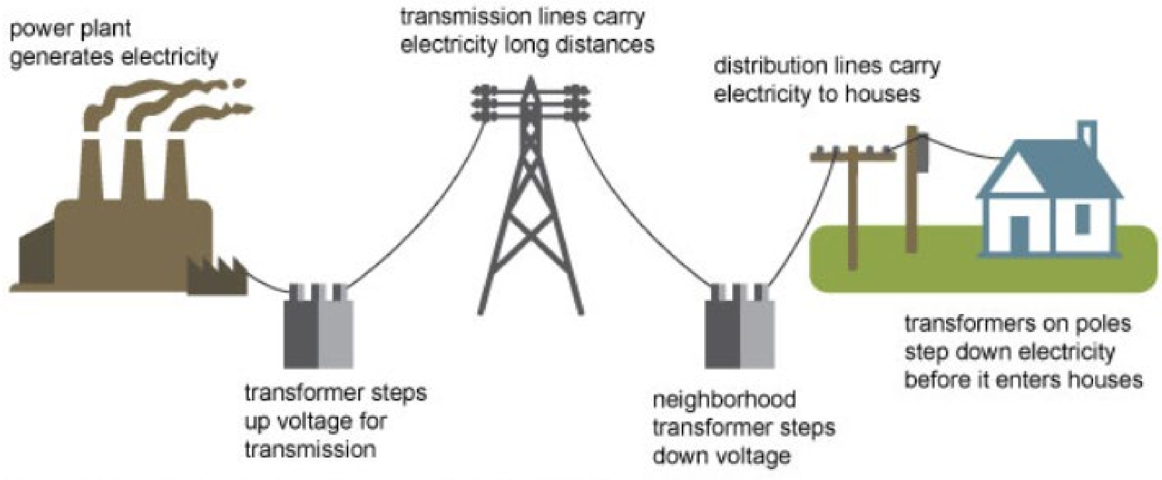
[5] The transmission system is a network of interconnected high-voltage lines designed to transmit large amount of electricity while minimizing losses. The distribution system is a mesh of lower-voltage lines that are connected via substation to the high-voltage transmission system to distribute electricity to the points of consumption, such as homes, offices, stores, and factories. The U.S. interstate highway system is analogous to the transmission system, whereas local roads and streets are analogous to the electric distribution system.

[6] *Frequently Asked Questions "How much electricity is lost in electricity transmission and distribution in the United States?,"* U.S. Energy Information Administration, https://www.eia.gov/tools/faqs/faq.php?id=105&t=3. Note that EIA's 5% value is the average of annual T&D losses in 2014 through 2018.

[7] According to Ohm's law, voltage = current x resistance. Since power = current x voltage, applying Ohm's law on voltage yields power = current^2 x resistance.

[8] In highly simplified terms, marginal losses associated with a small change in peak load, which are proportional to square of the current or load, are twice the corresponding average loss rates. In reality, utility's marginal losses are less than twice the average losses due to the existence of other losses (*e.g.*, no load losses) that do not vary with square of the current.

Figure 1: Electricity Generation, Transmission, and Distribution System[9]



Source: U.S. Energy Information Administration.

Q. How does reduction in T&D losses avoid the need for new T&D capacity investments?

A. Power systems are planned and operated to meet the total system load, which includes losses in the T&D systems. When RMP delivers power to its customers, some of the energy is lost in transmission and distribution facilities (*e.g.*, lines, substations and transformers). Since CG is typically placed close to the load and the CG's output is consumed either onsite or by CG customer's neighbors, it can avoid losses in the T&D system, thus enhancing its value. Such avoided losses also have a "multiplier effect," since they further reduce the required amount of T&D capacity needed to enable a given amount of energy consumption by a customer. For example, RMP would need to prepare for about 111 MW of T&D capacity to meet 100 MW of demand, if RMP's system loss is about 10% (i.e., 111 MW x (1-10%) = 100 MW).

[9] *Electricity Explained How Electricity is Delivered to Consumers*, U.S. Energy Information Administration, https://www.eia.gov/energyexplained/electricity/delivery-to-consumers.php.

III. CALCULATIONS OF AVOIDED T&D CAPACITY COSTS

Q. Please provide an overview of this section.

A. In this section, I describe how I calculated the avoided T&D capacity costs that CG exports can avoid. For the avoided transmission capacity valuation (section III.A), I used PacifiCorp's (RMP's parent company) current FERC-approved firm transmission rate of $32.74/kW-year as a reasonable proxy for avoidable transmission costs.[10] For the avoided distribution capacity valuation (section III.B), I used PacifiCorp's marginal distribution capacity cost of [redacted]/kW and a utilization weighting of [redacted]%, as recommended by Mr. Volkmann.[11] I then adopted Dr. Milligan's effective capacity value of about 28% to determine the ability of CG exports in reducing the peak loads on the T&D systems.[12] In section III.C, I calculated the value of T&D losses avoided by CG exports using Mr. Volkmann's RMP-specific marginal loss expansion factors of about 1.091 and 1.046 for avoided transmission and distribution, respectively.[13]

Q. Please describe the T&D capacity benefits of CG exports in RMP's service territory.

A. The T&D capacity benefits of CG exports in RMP's service territory represent the avoided or delayed costs of maintaining and upgrading infrastructure related to the transmission and distribution of electricity across the grid. Namely, CG exports can help RMP defer or avoid additional investment in T&D assets by reducing peak demand and system losses.

[10] *PacifiCorp Transmission and Ancillary Services Rates*, PacifiCorp OASIS Tariff/Company Information, Rate Table, Schedules 7 and NITS, http://www.oasis.oati.com/woa/docs/PPW/PPWdocs/Rate_Table_20190601.pdf (Rates as of June 1 ,2019).
[11] Vote Solar, *Revised Affirmative Testimony of Curt Volkmann,* lines 127–32.
[12] Vote Solar, *Revised Affirmative Testimony of Michael Milligan*, lines 528–31.
[13] Vote Solar, *Revised Affirmative Testimony of Curt Volkmann*, line 51.

Q. What inputs are used to calculate avoided T&D capacity costs?

A. To determine deferred or avoided T&D investment, two key inputs are needed: (i) the effective capacity associated with CG exports and (ii) RMP's T&D capacity costs. Effective CG capacity is the actual fraction of exported CG capacity that could reliably offset RMP's T&D capacity and is a reasonable measure to use when determining avoided T&D capacity costs related to CG for purposes of informing an export credit rate. Avoided T&D capacity costs are the product of the effective CG capacity times RMP's T&D capacity costs.

Q. What is the effective CG capacity?

A. Effective CG capacity refers to the capacity contribution that CG exports makes to reducing the peak loads on the transmission and distribution system that drives the utilities to incur T&D capacity costs. For example, if the effective CG capacity is 30%, one kW of CG exports can avoid 0.3 kW of the utility's T&D capacity investments. This represents the "capacity value" of the CG exports.[14]

Q. What information did you use to determine the effective CG capacity?

A. Dr. Michael Milligan estimated the annual effective capacity associated with CG exports on a system-wide basis—*i.e.*, based on the likelihood of coincidence between CG exports and system peak load. Since hourly occurrences of system peaks generally coincide with T&D peaks (as explained below) and CG avoids T&D capacity costs by reducing T&D peak loads,

[14] A measure of the capacity value (normally provided on a dollar per kW basis) is the amount of energy that can be reliably delivered to the system at the time of peak demand. This is different from energy value (typically provided on a dollar per kWh basis), which is measured by the amount of total energy delivered over the course of a year irrespective of coincidence with peak demand. Capacity value is needed for determining the avoided capacity costs, whereas energy value is needed for determining the avoided energy costs.

it is reasonable to assume that CG makes the same contribution to avoiding T&D capacity that it does to avoiding generation capacity. As a result, in determining the avoided T&D capacity, I adopted Dr. Milligan's estimate of the annual effective CG capacity of approximately 28% for each year of the 2021–2040 time period.[15]

Q. Can you explain how system peaks generally coincide with T&D peaks?

A. Yes. With respect to hourly coincidence between the system and transmission peaks, Table 2 below shows PacifiCorp's system peak and transmission peak hours during the 2004–2018 time period. In nine of fifteen years (highlighted), PacifiCorp's system reached peaks at the same dates and hours as the corresponding transmission peaks. With respect to hourly coincidence between the system and distribution peaks, Figure 2 below shows RMP's system coincident peaks and distribution coincident peaks over the last five filed cost of service studies. This figure demonstrates significant and persistent overlap between RMP's system and distribution peaks over time, especially for summer months, when the CG export amount is at the zenith. I conclude that it is reasonable to assume that CG exports make the same contribution to avoiding T&D capacity that they do to avoiding generation capacity.

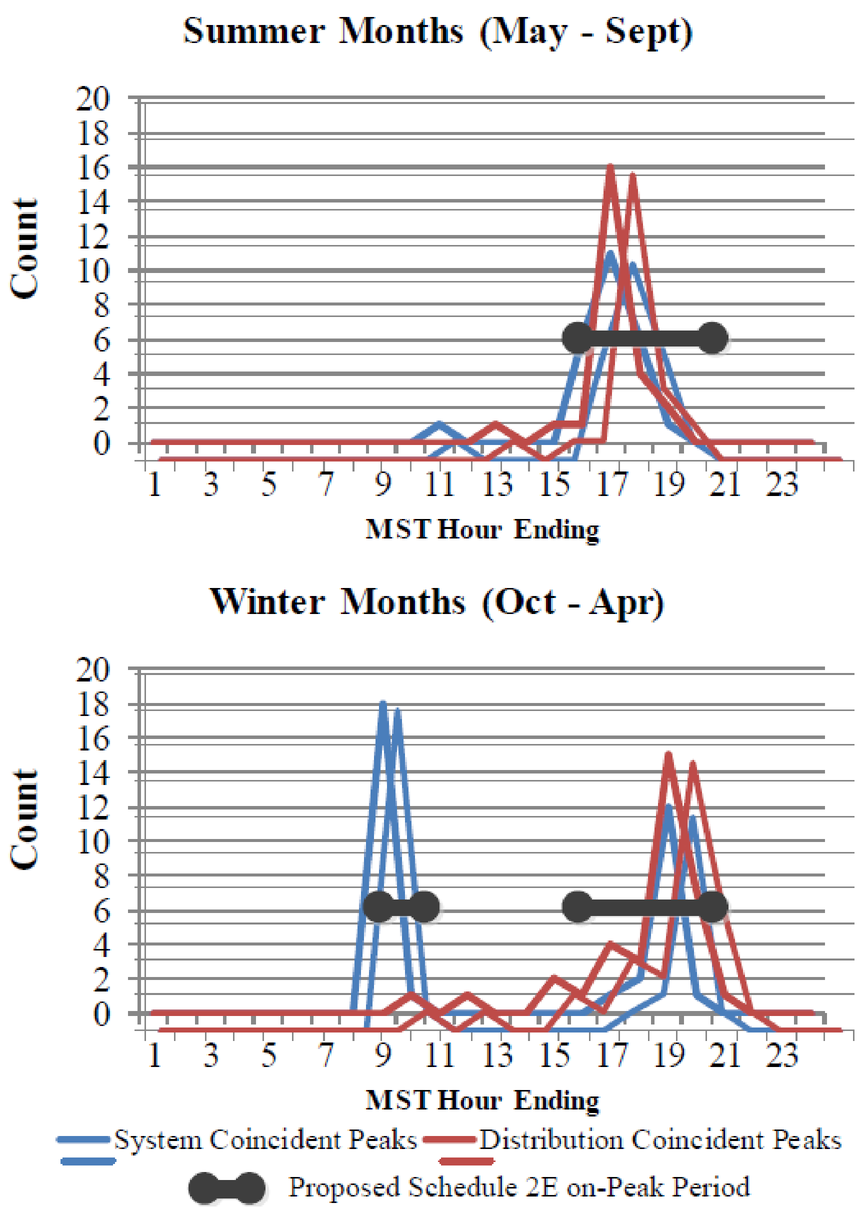
[15] Vote Solar, *Revised Affirmative Testimony of Michael Milligan*, lines 528–31.

Table 2: PacifiCorp's Annual System and Transmission Peak Hours (2004–2018)[16]

Year	System Peak Date	System Peak Hour	Transmission Peak Date	Transmission Peak Hour
2018	7/16/2018	1700	7/16/2018	1700
2017	8/1/2017	1700	8/1/2017	1700
2016	7/28/2016	1700	7/28/2016	1700
2015	6/30/2015	1700	7/29/2015	1600
2014	7/14/2014	1600	7/14/2014	1600
2013	7/1/2013	1600	7/1/2013	1600
2012	7/12/2012	1500	7/12/2012	1500
2011	8/23/2011	1700	7/23/2011	1700
2010	8/16/2010	1600	8/17/2010	1600
2009	7/27/2009	1700	7/27/2009	1700
2008	7/9/2008	1700	6/9/2008	1700
2007	7/10/2007	1700	7/10/2007	1700
2006	7/24/2006	1500	7/21/2006	1700
2005	7/20/2005	1700	7/20/2005	1700
2004	7/14/2004	1600	6/14/2004	1600

[16] *PacifiCorp's annual FERC Form 1 data*, Federal Energy Regulatory Commission, p. 400, https://www.ferc.gov/docs-filing/forms/form-1/data.asp (last accessed March 2, 2020).

Figure 2: Hourly Occurrence of Peaks from Last Five Filed Cost of Service Studies (Docket No. 11-035-200, Docket No. 13-035-184, 2013 Annual, 2014 Annual, 2015 Annual)[17]



[17] Rocky Mountain Power, *Direct Testimony of Robert M. Meredith*, Docket No. 16-035-36, Ex. 3-Timing Peaks, Jan. 31, 2017, https://pscdocs.utah.gov/electric/16docs/1603536/291437ExMeredithTestRMP(RMM-3)TimPeaks1-31-2017.pdf.

Q. What methods are typically used for calculating avoided T&D capacity costs?

A. There are many methods to calculate avoided T&D capacity costs.[18] These include:

- System Planning Approach: This method uses the utility's forecasted load and projected T&D additions with and without incremental blocks of peak load reducing instruments like CG. According to the U.S. Environmental Protection Agency, this is the most appropriate approach for estimating avoided T&D costs.[19] But this approach is also the most time consuming to conduct, and it requires in-depth information of the utility's transmission and distribution systems and a sophisticated modeling software to perform.
- Marginal Cost Approach: This method uses a utility's marginal cost study data to develop estimates of avoided T&D costs. California's investor-owned utilities like Southern California Edison, San Diego Gas, and Electric and Pacific Gas and Electric, as well as Oregon's Portland General Electric, use their marginal cost studies to estimate their marginal distribution capacity costs that can be avoided by demand reducing instruments like CG solar.[20] NV Energy used the marginal cost study associated with the utility's 2010 rate case to determine its avoided T&D costs.[21]

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[18] *See* The Mendota Group, LLC, *Benchmarking Transmission and Distribution Costs Avoided by Energy Efficiency Investments,* Public Service Company of Colorado, Oct. 23, 2014, https://mendotagroup.com/wp-content/uploads/2018/01/PSCo-Benchmarking-Avoided-TD-Costs.pdf.

[19] *Assessing the Multiple Benefits of Clean Energy, A Resource for States,* U.S. Environmental Protection Agency, 76, Sept. 2011, https://archive.epa.gov/epa/sites/production/files/2015-08/documents/epa_assessing_benefits.pdf.

[20] Portland General Electric Company, *Portland General Electric Resource Value of Solar Filing,* Public Utility Commission of Oregon, Docket No. UM 1912, PGE/400 Murtaugh, p. 7, Dec. 4, 2017, https://edocs.puc.state.or.us/efdocs/HAA/haa163313.pdf.

[21] Sierra Pacific Power Company d/b/a NV Energy, Nevada Power Company d/b/a NV Energy, *Application of Sierra Pacific Power Company d/b/a NV Energy Seeking Acceptance of its Triennial Integrated Resource Plan covering the period 2014-2033 and Approval of its Energy Supply Plan for the period 2014-2016, Volume 6 of 16 Demand Side Plan,* Public Utilities Commission of Nevada, Docket No. 13-07005, p. 49, July 1, 2013, http://pucweb1.state.nv.us/PDF/AxImages/DOCKETS_2010_THRU_PRESENT/2013-7/27851.pdf.

- Deferrable Project Approach: Some utilities use a variant of the System Planning Approach by identifying known capacity additions to the T&D system and estimating the deferrable value of those investments. For example, PacifiCorp calculates avoided T&D costs for the Demand Side Management ("DSM") program by selecting the T&D projects that would have the potential to be deferred through the DSM program for the subsequent five years, dividing the total project costs by the total increased capacity in kW and then annualizing this number by multiplying applicable carrying charges and utilization factors to obtain $/kW-year T&D deferral value.[22] PacifiCorp also used this approach in Oregon's Resource Value of Solar study, which resulted in a transmission deferral value of $5.94/kW-year and a distribution deferral value of $13.44/kW-year.[23]

- FERC Form 1 Approach: Absent system planning information or a marginal cost study, one can use publicly available data on actual T&D system investments to calculate an average avoided T&D cost—*e.g.*, using the utility's FERC Form 1 data on actual cost of transmission and distribution plant and peak system capability to calculate the $/kW-year T&D capacity costs. For example, MidAmerican used publicly available FERC Form 1 data to estimate the average avoided cost per kW associated with load reductions.[24]

[22] Exhibit 2-SSY, Attach Vote Solar 7.2 CONF.xlsx, RMP's Responses to Vote Solar 7th Set Data Requests – Attach 7.2 (Oct. 10, 2019).
[23] PacifiCorp, *PacifiCorp's Resource Value of Solar Filing,* Public Utility Commission of Oregon, Docket No. UM 1910, PAC/200 Putnam, p. 2, Nov. 30, 2017, https://edocs.puc.state.or.us/efdocs/HTB/um1910htb145759.pdf.
[24] MidAmerican Energy Company, *Direct Testimony of Jennifer L. Long*, Iowa Utilities Board, Docket No. EEP-2012-0002, p. 3–4, Feb. 1, 2013, https://efs.iowa.gov/cs/idcplg?IdcService=GET_FILE&dDocName=140323&allowInterrupt=1&noSaveAs=1&RevisionSelectionMethod=LatestReleased.

- Current Tariff Approach: This method uses a utility's firm transmission rate as a proxy for avoided transmission costs. The basic logic behind this approach is that reduced peak loads on the transmission system would make incremental firm transmission capacity available for sale to other transmission customers. In Maine's value of solar study, Clean Power Research used historical transmission tariffs as a proxy for the cost of future transmission that is avoidable or deferrable through the use of distributed generation.[25] In Oregon's value of solar study, Portland General Electric used Bonneville Power Administration's firm transmission rate of $21.52 per kW-year for avoided transmission.[26]

Q. What approach did you use to calculate the avoided T&D costs?

A. I used the Current Tariff Approach for avoided transmission and PacifiCorp's Deferrable Project Approach for avoided distribution, for reasons I explain more fully below in Section III.A and Section III.B, respectively.

[25] Clean Power Research, Sustainable Energy Advantage, LLC, and Pace Law School Energy and Climate Center, *Maine Distributed Solar Valuation Study*, Maine Public Utilities Commission, p. 32–33, Apr. 14, 2015, https://www.maine.gov/mpuc/electricity/elect_generation/documents/MainePUCVOS-FullRevisedReport_4_15_15.pdf.
[26] Portland General Electric Company, *Portland General Electric Resource Value of Solar Filing,* Public Utility Commission of Oregon, Docket No. UM 1912, PGE/400 Murtaugh, p. 7, Dec. 4, 2017 https://edocs.puc.state.or.us/efdocs/HAA/haa163313.pdf.

A. CALCULATIONS OF AVOIDED TRANSMISSION CAPACITY COSTS

Q. What are avoided transmission capacity costs?

A. Avoided transmission capacity costs represent the costs that utilities and ratepayers can save from avoided or postponed transmission infrastructure upgrades. CG exports in RMP's service territory are consumed by customers on the distribution system, reducing present and future electricity transmission needs. CG exports relieve RMP's requirement to supply power at a particular location using its transmission network and therefore effectively reduce transmission congestion/constraints, transmission losses, and the need for additional transmission capacity.

Q. What approach did you take to determine a value for avoided transmission capacity costs?

A. I adopted the Current Tariff Approach for this testimony. Specifically, I used PacifiCorp's current FERC-approved firm transmission rate of about $32.74/kW-year[27] as a reasonable proxy for RMP's avoided transmission capacity costs.

Q. Why is the Current Tariff Approach a reasonable proxy for avoided transmission costs in this case?

A. PacifiCorp's transmission network is centrally designed to reliably transport power from its portfolio of generation resources (inclusive of market purchases) to various load centers, such

[27] *PacifiCorp Transmission and Ancillary Services Rates*, PacifiCorp OASIS Tariff/Company Information, Rate Table, Schedules 7 and NITS, http://www.oasis.oati.com/woa/docs/PPW/PPWdocs/Rate_Table_20190601.pdf (Rates as of June 1, 2019).

as RMP's retail customers in Utah. Since 2011, PacifiCorp has calculated this firm transmission rate annually using its FERC Form 1 actual costs and projected transmission additions. According to PacifiCorp, this formula rate provides the *"best mechanism"* to estimate a rate that reflects an *"accurate representation of the Company's transmission costs."* [28] Thus, I conclude this rate represents a reasonable proxy for RMP's avoided transmission costs to the extent that CG reduces peak loads on the transmission network, making additional firm transmission capacity available to serve other transmission customers.

Q. Did you attempt to calculate avoided transmission costs based on any of the other methods identified?

A. Yes. I attempted to calculate avoided transmission costs based on PacifiCorp's Deferrable Project Approach, which is the method I employed for avoided distribution costs, as described in further detail below. However, in my review of the transmission projects identified by PacifiCorp for deferral, I found significant omissions. For example, PacifiCorp failed to include Gateway West, South, and Central projects as deferrable projects, contrary to the Commission's conclusions that such projects were deferrable. [29] I also considered other methods and adopted the Current Tariff Approach because this method for estimating avoided transmission costs was transparent, easily reproducible, and PacifiCorp attested that its current

[28] PacifiCorp, *Testimony of Kenneth T. Houston on behalf of PacifiCorp*, FERC Docket No. ER11-3643, p. 9, lines 5-10, May 24, 2011, http://www.oasis.oati.com/woa/docs/PPW/PPWdocs/20110526_FERCRC_AttachD_Houston.pdf (emphasis added).

[29] Public Service Commission of Utah, *Updates and Revisions to Avoided Cost Pricing Methodologies for QF Resources,* Docket No. 17-035-37, p. 18–19, Jan. 23, 2018, https://pscdocs.utah.gov/electric/17docs/17035T07/29931117035T07and1703537o1-23-2018.pdf.

tariff (that I used as a proxy for RMP's avoided transmission costs) reflects an accurate representation of its average transmission costs.

Q. How did PacifiCorp's average firm transmission rate change over time?

A. As shown in Figure 3 below, PacifiCorp's FERC-approved firm transmission rate went up steadily over time, from $24.30/kW-year in 2010 to $32.74/kW-year in 2019.[30] This steady increase was primarily driven by PacifiCorp's substantial investment in transmission facilities. Figure 4 below shows PacifiCorp's cumulative investment in transmission.[31] Specifically, PacifiCorp has increased its investment in the net transmission plant from approximately $4.3 billion in 2010 to $6.4 billion in 2018. This represents over $2 billion, or a 46% increase in PacifiCorp's transmission investment in nine years. This average firm transmission rate is expected to rise further after PacifiCorp is able to include major transmission projects like the "deferrable" Gateway South project into the rate base.[32] CG exports can avoid and defer PacifiCorp's need for "load-related" transmission investments[33]

[30] PacifiCorp's FERC transmission formula annual update filings (2011–2019), projected annual firm point-to-point and network integration transmission service billing rate. *See OATT Pricing*, PacifiCorp OASIS Tariff/Company Information, http://www.oatioasis.com/ppw/index.html (Current Rates–Rate Table, Schedules 7 and NITS–and Historical Rates–"PacifiCorp_Historical_Transmission_Rates.xlsx, Sch_7_8_NITS" tab). *See* Workpapers 1-SSY, Figure 3 Tab for more details.

[31] *See* PacifiCorp's annual FERC Form 1 Filings (2010–2018), page 207, line 58, https://www.ferc.gov/docs-filing/forms/form-1/data.asp. The FERC Form 1 data, annually submitted by major utilities, provides comprehensive financial and operating data of the utility for the previous year. Major is defined as having (i) 1 million Megawatt hours or more; (ii) 100 megawatt hours of annual sales for resale; (iii) 500 megawatt hours of annual power exchange delivered; or (iv) 500 megawatt hours of annual wheeling for others (deliveries plus losses). *See FERC Form 1 - Electric Utility Annual Report Data (Current and Historical)*, Federal Energy Regulatory Commission, https://www.ferc.gov/docs-filing/forms/form-1/data.asp (last updated July 9, 2019).

[32] In its January 2018 Order, the Commission concluded that the megaprojects like Gateway South are also deferrable by a QF. *See* Public Service Commission of Utah, *Updates and Revisions to Avoided Cost Pricing Methodologies for QF Resources*, Docket No. 17-035-37, p. 18–19, Jan. 23, 2018, https://pscdocs.utah.gov/electric/17docs/17035T07/29931117035T07and1703537o1-23-2018.pdf. Like QFs, CG exports reduce PacifiCorp's peak load and thus can similarly defer or avoid PacifiCorp's applicable transmission investments.

[33] Note that FERC Form 1 data report aggregate annual transmission investments and do not separately track load-

in proportion to the likelihood that CG exports will occur at times of peak demand on the transmission system (as I explain below).

related transmission investments. CG exports do not defer or avoid transmission investments that are not load-related, such as investments needed for replacing old transmission infrastructure.

Figure 3: PacifiCorp's FERC-Approved Annual Firm Transmission Rate

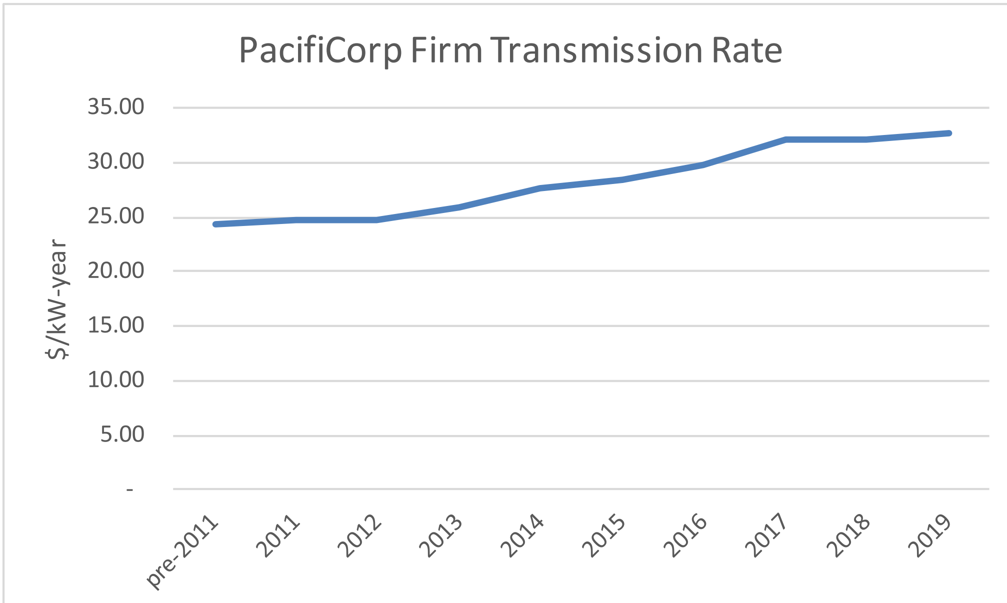
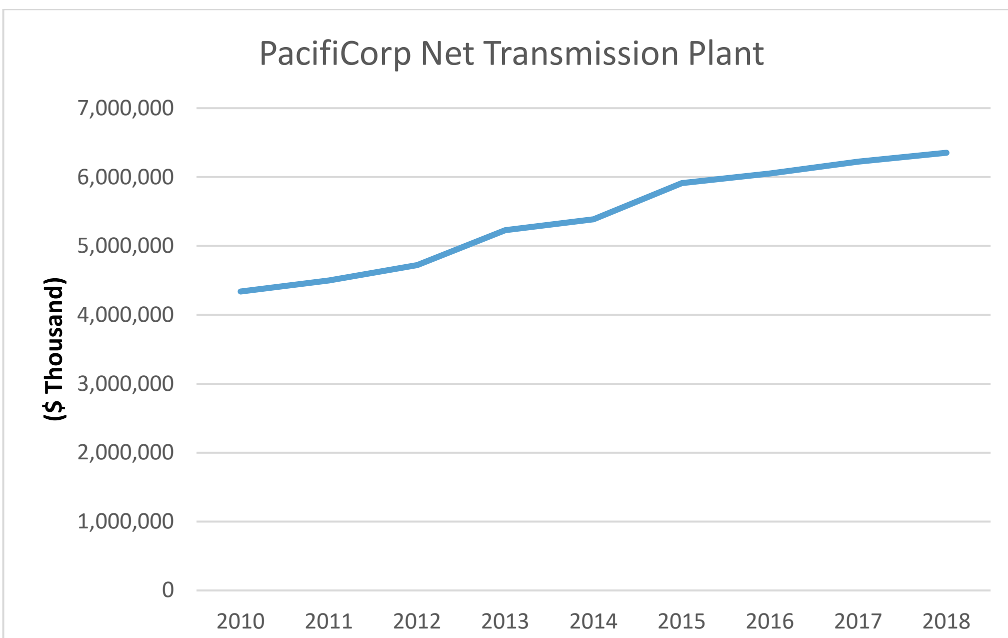


Figure 4: PacifiCorp's Cumulative Investment in Net Transmission Plant



Q. PacifiCorp's firm transmission rate includes costs not related to CG exports. Did you assume that all transmission costs are avoidable?

A. No. I did not assume that all transmission costs included in the firm transmission rate are avoidable. Rather, I reasoned that CG exports reduce peak loads and reduced peak loads on the transmission system would make incremental firm transmission capacity available for sale to other transmission customers. In fact, PacifiCorp does not have to actually post incremental additional capacity for sale to other transmission customers to monetize benefits from reduced peak loads. Rather, the benefits accrue automatically because CG exports help PacifiCorp to reduce current peak load and future load growth, thus avoiding and deferring the need for load-related T&D investments. Moreover, PacifiCorp asserted that this formula rate provides the *"best mechanism"* to estimate a rate that reflects an *"accurate representation of the Company's transmission costs."*[34] Thus, this rate can be used as a reasonable proxy to measure RMP's avoided transmission costs. This approach is not new. Other states like Oregon and Maine used a firm transmission rate as a reasonable proxy in valuing the avoided transmission capacity benefits attributable to DG solar (as I explain above). Finally, it is important to note that I only allocated a fraction of transmission costs that PacifiCorp would otherwise have to incur but for CG exports. Stated differently, my calculation of the avoided transmission costs is the product of the CG export's capacity contribution factor times PacifiCorp's current firm transmission rate. And the capacity contribution factor only considers the ability of CG

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[34] PacifiCorp, *Testimony of Kenneth T. Houston on behalf of PacifiCorp*, FERC Docket No. ER11-3643, p. 9, lines 5-10, May 24, 2011, http://www.oasis.oati.com/woa/docs/PPW/PPWdocs/20110526_FERCRC_AttachD_Houston.pdf (emphasis added).

exports to reduce the peak loads that drive marginal transmission investments; thus it discounts transmission capacity costs to the proportion that could be reasonably offset by CG exports.

Q. What were your next steps in calculating avoided transmission capacity costs?

A. Next, I calculated the annual avoided transmission rate attributable to CG exports by multiplying (i) PacifiCorp's current firm transmission rate of $32.74/kW-year [35] and (ii) effective CG export capacity of about 28% calculated by Vote Solar's witness, Dr. Milligan.[36] I then calculated the annual nominal avoided transmission costs using the RMP-specific annual amount of the CG exports (about 896 kWh/kWac) based on the study of another Vote Solar witness, Dr. Albert Lee.[37]

Q. How did you calculate a final levelized avoided transmission capacity value, and what was your estimated amount?

A. A standard practice of "levelization" concerns a way to reduce the annual stream of numbers over multi-year periods to a single number. Levelization generally employs discounting for the time value using a discount factor, which provides greater weight to values during the early years of a given time period and less weight to values at the tail end. In an electricity sector, a Levelized Cost of Energy ("LCOE") measures the average total cost of a generation technology per unit of total electricity generated—*i.e.*, lifetime costs (in dollars) divided by

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[35] $35.71/kW-year inclusive of line losses.

[36] Vote Solar, *Revised Affirmative Testimony of Michael Milligan*, lines 528–31.

[37] Lee, Exhibit 1-AJL-REVISED. Note Exhibit 1-AJL-REVISED reports capacity in kWdc term. I divide the kWdc by 1.2 to obtain kWac value. The 1.2 DC/AC conversion factor can be found at *PVWatts Calculator*, https://pvwatts.nrel.gov/pvwatts.php.

total energy production (in kWh)—by calculating net present value of annual costs and corresponding productions over an assumed lifetime (in $/kWh).[38] To determine a final levelized avoided transmission capacity value, I calculated net present value of the annual avoided transmission capacity costs over the 20-year time period using a discount rate of 6.92% (based on the PacifiCorp's 2019 IRP study).[39] This analysis produces a levelized annual avoided transmission cost of 1.23 cents/kWh in 2021 dollars (or 1.34 cents/kWh inclusive of line losses. I explain T&D losses below in Section III.C).

[38] Thus, LCOE allows a standard comparison of different technologies (e.g., wind, solar, natural gas) of unequal life spans, costs, sizes and productions. *See Levelized Cost of Energy (LCOE),* Corporate Finance Institute, https://corporatefinanceinstitute.com/resources/knowledge/finance/levelized-cost-of-energy-lcoe.

[39] *2019 Integrated Resources Plan*, PacifiCorp, Volume 1, p. 179, Oct. 18, 2019, https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificorp/energy/integrated-resource-plan/2019_IRP_Volume_I.pdf.

B. CALCULATIONS OF AVOIDED DISTRIBUTION CAPACITY COSTS

Q. What is avoided distribution capacity investment?

A. Avoided distribution capacity investment represents the costs that utilities and ratepayers can save from postponed distribution infrastructure upgrades. CG exports, at the current adoption level, reduce the need for RMP distribution investments by providing power locally, reducing the required power flow through the distribution grid.

Q. What information did you use to determine planned distribution investments?

A. Vote Solar witness, Mr. Volkmann, identified and reviewed the reasonableness of RMP's reported deferrable distribution investments. These investments included [redacted] planned capacity additions from 2019 to 2024 totaling [redacted] million.[40] Mr. Volkmann opined that this amount was reasonable for use in the distribution deferral value calculation.[41] On a per unit basis, this amount translated to about $[redacted] per kW for new distribution investments. RMP applied a Utah-specific "utilization weighting" of approximately [redacted]% to determine a Utah-specific distribution deferral value. Based on his experience, Mr. Volkmann also opined that it was appropriate to apply a utilization factor to account for the impact of CG in deferring distribution capacity projects across the RMP system.[42] Applying the Utah-specific utilization factor reduced the value of $[redacted] per kW for new distribution investments to $[redacted] per kW in deferrable investments.

[40] This amount included pre-2019 investment of about [redacted] million or about [redacted]% of the total planned investment amount.
[41] Vote Solar, *Revised Affirmative Testimony of Curt Volkmann,* lines 188–91.
[42] *Id*.

Q. How did RMP annualize the amount of new capital investments on a $/kW-year basis?

A. RMP applied an economic carrying charge factor of [redacted]% for Utah to annualize the amount of new capital investments on a $/kW-year basis. It is a standard practice in the utility ratemaking process to apply a fixed carrying charge factor to convert the marginal investment in a new plant to annual costs.[43] Applying RMP's carrying charge factor of [redacted]% to the Utah-specific marginal distribution investments of about $[redacted] per kW resulted in the annualized distribution deferral value of $[redacted] per kW-year.[44] RMP used this amount to calculate a distribution deferral value credit for DSM customers.[45]

Q. Did you find all of RMP's assumptions reasonable?

A. No. RMP's carrying charge factor assumption of [redacted]% was lower than the typical carrying charge factor assumption of about 10%.[46] In fact, RMP's carrying charge factor assumption was also lower than the amount PacifiCorp used in other proceedings. For example, in its 2018 marginal cost of service filing before the California Public Utilities Commission,

[43] In the utility ratemaking process, "carrying charges" refers to the revenue needed to support an investment, which includes return on debt and equity, income and property tax, book depreciation, and insurance. A carrying charge factor refers to the amount of revenue per dollar of investment that must be collected from ratepayers to recoup the carrying charges on that investment.
[44] Exhibit 2-SSY, Attach Vote Solar 7.2 CONF.xlsx, RMP's Responses to Vote Solar 7th Set Data Requests – Attach 7.2 (Oct. 10, 2019).
[45] Exhibit 3-SSY, *Response to Vote Solar Data Request 7.6*, RMP's Responses to Vote Solar 7th Set Data Requests (Oct. 10, 2019).
[46] *See, e.g.,* Jim Lazar and Xavier Baldwin, *Valuing the Contribution of Energy Efficiency to Avoided Marginal Line Losses and Reserve Requirements,* Regulatory Assistance Project, p. 6, Aug. 2011, https://www.raponline.org/wp-content/uploads/2016/05/rap-lazar-eeandlinelosses-2011-08-17.pdf ("The capital cost of augmenting transmission capacity is typically estimated at $200 to $1,000 per kilowatt and the cost of augmenting distribution capacity ranges between $100 and $500 per kilowatt. *Annualized values (the average rate of return multiplied by the investment over the life of the investment) are about 10% of these figures,* or $20 to $100 per kilowatt-year for transmission and $10 to $50 per kilowatt-year for distribution. There are also marginal operations and maintenance costs for transmission and distribution capacity, but these are modest in comparison to the capital costs") (emphasis added)).

PacifiCorp used 10.79% as the distribution carrying charge factor.[47] For the purposes of this testimony, I adopted this annual distribution carrying charge rate of 10.79% to develop the annual costs for additional distribution capacity. Using the new carrying charge rate, I obtained annual distribution costs of $13.24 per kW-year.

Q. What were your next steps in calculating avoided distribution capacity costs?

A. As with transmission, I calculated the annual avoided distribution rate attributable to CG exports by multiplying my annual distribution costs of $13.24/kW-year[48] and the effective CG export capacity of about 28% calculated by Vote Solar witness, Dr. Milligan. I then calculated the annual nominal avoided distribution costs using the RMP-specific annual amount of the CG exports (about 896 kWh/kWac) based on the study of another Vote Solar witness, Dr. Lee.

Q. How did you calculate a final levelized avoided distribution value, and what was your estimated value?

A. As with transmission, I calculated net present value of the annual avoided distribution capacity costs over the 20-year time period using a discount rate of 6.92% (based on PacifiCorp's 2019 IRP study.) This analysis produced a levelized annual avoided distribution cost of 0.50

[47] PacifiCorp, *Direct Testimony of Robert M. Meredith,* California Public Utilities Commission, Application No. 18-04-002, Exhibit PAC/1202, p. 52, Apr. 12, 2018, https://www.pacificpower.net/content/dam/pcorp/documents/en/pacificpower/rates-regulation/california/filings/docket_a_18_04_002/4-12-18_application/14_Exhibit_PAC_1202_REDACTED.pdf. Although some tables containing confidential data were redacted, all of the summary tables described in Mr. Meredith's testimony were included in the public version of his exhibit. I used this public version of his exhibit to obtain the PacifiCorp's carrying charge rates assumptions. Note that the 10.79% factor included administration & general ("A&G") expense loading factor of 0.71%. Inclusion of this A&G loader is reasonable because this loader is designed to account for overhead expenses that increase with investment.

[48] $13.86/kW-year inclusive of line losses.

cents/kWh in 2021 dollars (or 0.52 cents/kWh inclusive of line losses as I explain below in section III.C).

C. CALCULATION OF AVOIDED T&D LOSSES

Q. How did you calculate a value for avoided T&D losses?

A. I also included a value for avoided T&D line losses attributable to CG exports in my avoided T&D benefits. As I explain above, the proportion of CG's output that is exported to the grid is likely to be consumed by CG customer's neighbors, thus eliminating losses on the upstream portions of the distribution system and the entirety of the higher voltage transmission system. Vote Solar witness, Mr. Volkmann, has calculated both transmission and distribution line loss factors for CG exports. To include a value of avoided T&D losses, I applied the 9.1% combined transmission and distribution system line loss factor to avoided costs for transmission capacity and 4.6% distribution line loss factor to avoided costs for distribution capacity.

Q. What were the results of your avoided T&D losses calculation?

A. I found that the value of avoided line losses attributable to CG exports resulted in 0.11 cents/kWh and 0.02 cents/kWh in 2021 dollars for transmission and distribution, respectively. I included these benefits when reporting my avoided T&D capacity values.

IV. RESULTS OF AVOIDED T&D CAPACITY COSTS

Q. Please summarize your results.

A. Table 3 below summarizes my results. I conclude that the value of avoided T&D capacity costs due to CG exports is at least 1.86 cents/kWh.

Table 3: Value of Avoided T&D Capacity Costs (2021 cents/kWh)

Value Category	Value in 2021 cents/kWh
Avoided T Value	1.34
Avoided D Value	0.52
Avoided T&D Value	1.86

V. CONCLUSION

Q. Please summarize your conclusions.

A. Based on my analysis and evidence reviewed, I conclude that the value of avoided T&D capacity costs due to CG exports in RMP's service area is at least 1.86 cents/kWh.

Q. Does this conclude your revised testimony?

A. Yes.

CERTIFICATE OF SERVICE

I hereby certify that on this 8th day of May, 2020 a true and correct copy of the foregoing was served by email upon the following:

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