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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 CURT VOLKMANN

ON BEHALF OF

VOTE SOLAR

March 3, 2020

Table of Contents

I. Introduction

Q. Please state your name and business address.

A. My name is Curt Volkmann. My business address is 132 Lake Vista Circle, Fontana, Wisconsin, 53125.

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 President and founder of New Energy Advisors, LLC, an independent consulting firm. I work with clients in a variety of regulatory proceedings related to distribution system planning, distributed energy resources, and grid modernization.

Q. Please summarize your education and professional experience.

A. I have a BS in Electrical Engineering from the University of Illinois with a concentration in Electrical Power Systems. I also have an MBA from the University of California at Berkeley with a concentration in Finance. I have 35 years of experience in the utilities industry, primarily in electric transmission and distribution. My work experience includes nine years at Pacific Gas & Electric in various transmission and distribution engineering roles and eighteen years at Accenture with several positions including Executive Director in the North American Utilities practice. Since 2015, I have worked independently and supported clients in distribution-related regulatory proceedings around the country. Exhibit 1-CV provides a statement of my qualifications and experience.

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

A. No. However, I have testified and commented before regulatory commissions in various distribution planning, grid modernization, and distributed energy resources proceedings in Arkansas, Arizona, California, Iowa, Illinois, Michigan, Minnesota, New York, Ohio, and Virginia. Exhibit 2-CV provides a summary of my prior testimony and contributions to comments since 2013.

II. Purpose of Testimony

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

A. I will explain the impacts that distributed customer generation ("CG") installations can have on the electric distribution system of Rocky Mountain Power ("RMP" or "Company"). Because over 99% of CG installations in RMP's Utah service territory are solar photovoltaic ("PV") systems, I focus my analysis on CG exports from solar PV.[1] Specifically, I will explain how CG exports can:

1) Defer or avoid distribution capacity costs;

[1] 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, July 1, 2019, https://pscdocs.utah.gov/electric/19docs/1903529/308974RMPCustmrOwndGeneandNetMeterReptforthePerdApril12018thrMarch3120197-1-2019.pdf.

2) Reduce line losses; and

3) Require negligible integration costs at RMP's current levels of CG penetration.

I will also provide recommendations for Vote Solar witnesses, Drs. Spencer Yang and Carolyn Berry, to incorporate these impacts into Vote Solar's proposed valuation of CG exports.

III. Summary of Recommendations

Q. Please provide a brief summary of your recommendations.

A. I recommend that valuation of CG exports:

1) Include a distribution capacity deferral component based on the distribution capacity costs and utilization weighting RMP uses for demand-side management programs in its Integrated Resources Plan ("IRP"). Vote Solar witnesses, Drs. Berry and Yang, provide details of the methodology for including these components.

2) Include the following loss expansion factors:

	Loss Expansion Factor	
Export Credit Component	Demand (MW)	Energy (MWh)
Avoided Energy		1.08621
Avoided Generation Capacity	1.09080	
Avoided Transmission Capacity	1.09080	
Avoided Distribution Capacity	1.04624	

3) Exclude any alleged RMP distribution costs for CG integration.

I also recommend that the Commission consider exploring the lessons learned and best practices from other states in implementing Integrated Distribution Planning to reduce costs and increase the reliability and sustainability of the distribution grid.

My lack of comments on any components of RMP's 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.

IV. CG Can Defer or Avoid Distribution Capacity Costs

1) Impact of CG on Peak Loads

Q. Does the output from CG reduce peak loads and the need for future distribution investments?

A. Yes. The output from CG reduces system loads and reduces the need for future distribution capacity expansion. Distribution capacity deferral benefits are greater when the solar CG output coincides with local substation or circuit peak demand.

Q. How does the output from CG reduce loads?

A. Customers install CG systems to directly serve the load of their home or business and offset the need to purchase electricity from the local utility. Any excess power not required at the customer home or business is exported and flows to serve other customers connected to the same distribution line transformer (*i.e.*, via the secondary distribution system). Occasionally, during low daytime load and high CG output conditions (*e.g.*, cool, bright sunny days), excess power may flow onto the primary system and serve additional local customer load. All output from CG systems, whether consumed by a customer's home or exported and consumed by neighboring loads, reduces the need for centralized generation and reduces the power flowing on the transmission and primary distribution system. In this analysis, I focus on the avoided distribution capacity costs associated with exported CG.

Q. What do you mean by primary and secondary distribution systems?

A. The primary distribution system includes the overhead and underground equipment between the distribution substation and pole-top and/or pad-mounted distribution line transformers, energized at primary distribution voltage levels. RMP's primary distribution voltages range from 2.2 kV to 34.5 kV, with most circuits at 12.5 kV.[2]

The secondary distribution system refers to the low-voltage (120V to 480V) overhead and/or underground equipment between pole-top and pad-mounted transformers and the customer meter. Figure 1 below illustrates the relationship between primary and secondary distribution systems.

[2] Exhibit 3-CV, Attach Vote Solar 6.3-1.xlsx, RMP's Responses to Vote Solar 6th Set Data Requests – Attach Vote Solar 6.3-1 (Aug. 23, 2019).

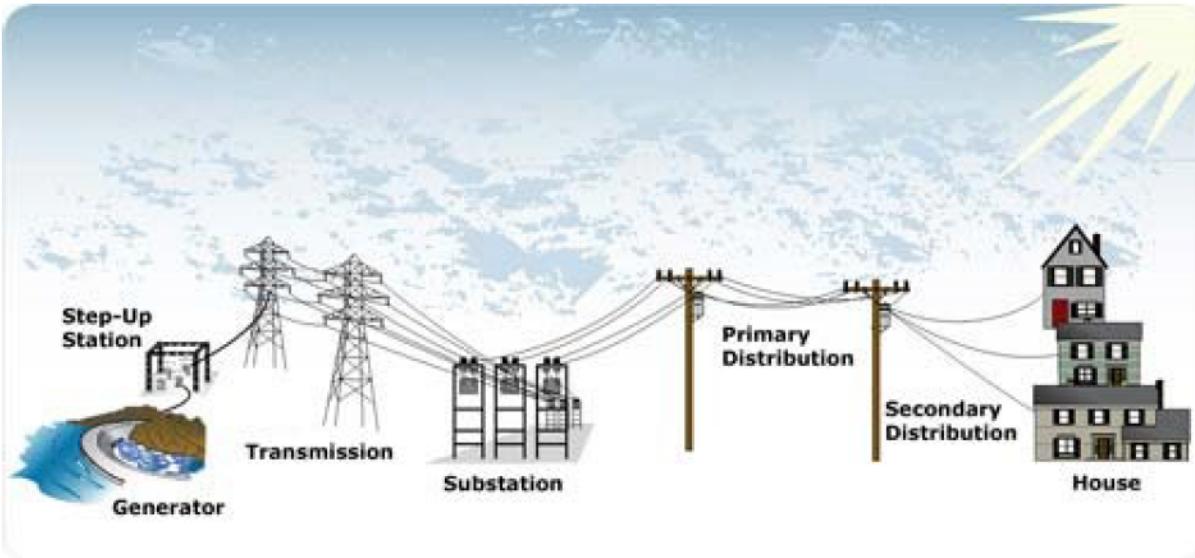

Figure 1 – Typical Conventional Electric Power System[3]

Q. Does the exported generation from CG reduce distribution peak loads?

A. Yes, in varying degrees. The output from CG's contribution to reducing distribution peak loads depends on its coincidence with the local peak when a circuit is most constrained. These local circuit peak periods are typically only a few hours every year, are not always coincident with the overall system peak, and are very dependent on the nature of the circuit load (*i.e.*, residential, commercial, or industrial). If the load is primarily commercial/industrial, the peak is typically earlier in a weekday when businesses are open and employees are at work. If the load is primarily residential, the peak is typically later in the day when customers return home and increase their electricity usage.

[3] *Transmission Line FAQ*, GATEWAY WEST Transmission Line Project, http://www.gatewaywestproject.com/faq_general_transmission.aspx (last visited Feb. 29, 2020).

Also, the timing of CG production depends on its orientation, with the peak output of south-facing panels occurring earlier in the day than for more west-facing panels. Therefore, the ability of CG exports to reduce circuit peak loads depends, among other factors, on circuit characteristics and the orientation of each CG system.

RMP was not able to provide information about the timing of its distribution peaks in response to a Vote Solar data request.[4] However, as Vote Solar witness, Dr. Yang, explains in his testimony, there is a significant and persistent overlap between RMP's system and distribution peaks, especially in summer months when CG output is the highest.[5]

Q. Does the output from CG reduce the need for distribution capital investment?

A. Yes. To the extent that CG exports coincide with local distribution loads, it can contribute to the deferral or avoidance of distribution capital investment for increased capacity.

2) <u>RMP's Approach to Quantifying Deferred Distribution Capacity Costs</u>

Q. Does RMP acknowledge the distribution capacity deferral value of customer-sited distributed energy resources?

[4] Exhibit 4-CV, *Response to Vote Solar Data Request 9.3(1)(b)*, RMP's Responses to Vote Solar 9th Set Data Requests (Feb. 6, 2020).
[5] Vote Solar, *Affirmative Testimony of Yang*.

A. Yes, the Company includes a distribution deferral value for demand-side management ("DSM"), such as energy efficiency programs, in its IRP.[6]

Q. How has RMP determined this distribution deferral value?

A. RMP has identified the cost and incremental capacity of planned distribution capacity additions in the next five years and calculates an average cost per kW. RMP converts this value to an avoided cost per kW-year based on distribution system utilization and a real levelized annual distribution carrying charge.

Q. What values has RMP calculated?

The Company identified [redacted] projects across the PacifiCorp companies adding [redacted] MW of distribution capacity at a total capital cost of [redacted] million. This is [redacted] per kW. The Company applies a utilization weighting of [redacted] for Utah and a real carrying charge of [redacted] to calculate a distribution deferral value for Utah of [redacted] per kW-year.[7] This is an updated value from the Utah distribution deferral value of $9.02 per kW-year shown in PacifiCorp's 2019 IRP.[8]

Q. Were you able to review details of the [redacted] distribution capacity projects included in these calculations?

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[6] Exhibit 5-CV, *Response to Vote Solar Data Request 6.5*, RMP's Responses to Vote Solar 6th Set Data Requests (Aug. 8, 2019).
[7] Exhibit 6-CV, Attach Vote Solar 7.2 CONF.xlsx, RMP's Responses to Vote Solar 7th Set Data Requests – Attach 7.2 (Oct. 10, 2019).
[8] *2019 Integrated Resources Plan*, PacifiCorp, Volume 1, p. 165, Table 6.8, October 18, 2019, https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificorp/energy/integrated-resource-plan/2019_IRP_Volume_I.pdf.

A. No. However, the brief descriptions of the projects and ranges of costs are consistent with capacity-related projects I have seen at other utilities. I consider it to be a representative list of PacifiCorp capacity-related distribution projects, but it may not be a comprehensive list.

Q. Is it unusual that you were unable to review details of the planned projects?

A. No it is not unusual, as distribution planning has historically been a very closed process with minimal regulator and stakeholder visibility into actual grid conditions and the rationale for planned projects. However, more and more states are taking steps to increase the transparency of distribution planning and take full advantage of customer-owned distributed energy resources to reduce costs. This is often referred to as Integrated Distribution Planning ("IDP").

Q. What do you recommend?

A. I recommend that the Commission consider exploring the lessons learned and best practices from other states in implementing IDP to reduce costs and increase the reliability and sustainability of the distribution grid.[9]

Q. Based on your experience, is the Company's calculated value of [redacted] per kW a reasonable number for the cost of distribution capacity additions?

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[9] *See, e.g.*, GridLab, *Integrated Distribution Planning – A Path Forward*, GridLab, 2018, http://gridlab.org/works/integrated-distribution-planning/; Regulatory Assistance Project, *Integrated Distribution Planning for Electric Utilities: Guidance for Public Utility Commissions*, RAP Online October 16, 2019, https://www raponline.org/knowledge-center/integrated-distribution-planning-for-electric-utilities-guidance-for-public-utility-commissions/.

A. Yes. Many utilities publish the cost per kW of historical and planned distribution capacity additions. [redacted] per kW is consistent with what I've seen with other utilities and is reasonable. Figure 2 below shows the cost per kW for distribution capacity additions from select utilities.

Company	Average $ per kW	Years	Docket No.
Con Edison	$223	2018	NY PSC 19-E-0283
New York State Electric & Gas (NYSEG)	$268	2018	NY PSC 19-E-0283
Orange & Rockland (O&R)	$291	2019-2028	NY PSC 19-E-0283
Rochester Gas & Electric (RG&E)	$310	2015-2019	NY PSC 19-E-0283
Xcel Energy - MN	$191	2017-2021	MN PUC E002/M-13-867

Figure 2 – Cost per kW for Select Utility Distribution Capacity Additions[10]

Q. Based on your experience, is it appropriate to include a utilization weighting to calculate the distribution deferral value?

A. Yes. As the Company explains,

> [The] utilization weightings represent the average loading of the distribution system in a given state, relative to the total distribution system capacity in that state. Applying the utilization weighting results in differentiation between regions with significant unused

[10] Consolidated Edison Company of New York, Inc., *The Marginal Cost of Service Study*, New York State Department of Public Service, Docket No. 16-00253, p. 22, July 30, 2018, http://documents.dps ny.gov/public/MatterManagement/CaseMaster.aspx?MatterCaseNo=16-E-0060&submit=Search; New York State Electric & Gas Corporation, *NYSEG Elec LSRV DRV MC 2018-07-30 1700*, New York State Department of Public Service, Docket No. 19-00952, June 21, 2019, http://documents.dps ny.gov/public/MatterManagement/CaseMaster.aspx?Mattercaseno=19-E-0283 (tab 'LSRV + DRV', average of cells J16:Z16); Orange and Rockland Utilities, Inc., *Workpapers for O&R 2019 MCOS*, New York State Department of Public Service, Docket No. 19-00952, June 21, 2019, http://documents.dps ny.gov/public/MatterManagement/CaseMaster.aspx?Mattercaseno=19-E-0283 (tab 'P_NetCost', average of cells F11:O60); NERA Economic Consulting, *Rochester Gas & Electric Corporation Marginal Cost of Electric Delivery Service*, p. 14, Oct. 23, 2015, http://documents.dps ny.gov/public/MatterManagement/CaseMaster.aspx?Mattercaseno=19-E-0283; Xcel Energy, *VOS Calculation, Community Solar Garden Program, Attachment P*, Minnesota Public Utilities Commission, Docket No. E002/M-13-867, p. 5, Aug. 30, 2019, https://www.edockets.state mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId={9016E46C-0000-C810-8D1C-569FF0B43870}&documentTitle=20198-155601-01.

> distribution capacity, which would not incur costs for additional distribution capacity until significant load growth occurs, and regions with little unused distribution capacity, which would require additional distribution capacity after a small amount of additional growth … [T]he idea is that for a state with a 60 percent utilization factor, approximately six out of 10 locations would have a distribution capacity need while four out of ten locations would not. If the transmission and distribution (T&D) capacity credit is to be applied to all locations in the state, and not targeted to locations with a near-term need, the effective benefits are expected to only be 60 percent of the cost of distribution upgrades, since not all locations would have incurred distribution upgrade costs in the first place.[11]

This is a reasonable approach to account for the impacts of DSM programs and a reasonable approach to account for the impact of CG in deferring distribution capacity projects across RMP's system.

Q. Is it reasonable to adopt RMP's capacity costs and utilization weighting to determine the distribution capacity deferral value for CG exports?

A. Yes. I previously explained how CG exports contribute to distribution peak load reduction in varying degrees, much like energy efficiency programs and other DSM measures contribute to peak load reduction in varying degrees. I have reviewed RMP's list of distribution projects and utilization weightings and find the assumptions to be reasonable to adopt for valuing CG exports.

Q. What do you recommend?

A. I recommend that the valuation of CG exports include a distribution deferral component based on a distribution capacity cost of [redacted] per kW and a utilization

[11] Exhibit 7-CV, *Response to Vote Solar Data Request 7.2(4)*, RMP's Responses to Vote Solar 7th Set Data Requests (Oct. 10, 2019).

weighting of [redacted] Vote Solar witnesses, Drs. Berry and Yang, provide details of the methodology for including these components in the valuation of CG exports.[12]

V. CG's Impact on System Losses

1) <u>Categories of System Losses</u>

Q. What are system losses?

A. Losses are the difference between the total energy inputs to a power delivery system and the total energy delivered to and paid for by customers. They consist of non-technical losses and technical losses. Typically, between five to ten percent of the total kWh requirements of an electric utility is lost or unaccounted for in the delivery of power to customers.[13]

Q. What are non-technical losses?

A. Non-technical losses are related to energy theft, metering, non-payment by customers, and accounting errors. Non-technical losses are generally very small and can be extremely difficult and subjective to quantify.[14]

Q. What are technical losses?

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[12] *See* Vote Solar, *Affirmative Testimony of Carolyn Berry*; Yang.

[13] Exhibit 8-CV, PacifiCorp Utah 2009 Analysis of System Losses_November 2011.pdf, p. 6, RMP's Responses to Vote Solar 6th Set Data Requests – Attach 6.8 (Aug. 16, 2019).

[14] *Id.* at 7.

A. Technical losses are a natural occurrence of power delivery systems and consist mainly of power dissipation in system components. Technical losses consist of no-load and load losses.

Q. What are no-load losses?

A. No-load losses represent energy required by a power system to energize various components regardless of their loading levels. The major portion of no-load losses consists of core or magnetizing energy related to transformers installed throughout the power system.[15]

Q. What are load losses?

A. Load losses are caused by the electrical resistance of a power system and are proportional to the square of the current. As system load or current increases, system components lose more energy in the form of heat, and load losses increase exponentially. Load losses are therefore greatest during peak loading periods.

2) <u>Losses on RMP's System</u>

Q. How has RMP quantified losses on its system?

A. RMP conducted its most recent system line loss study in 2011 based on 2009 data. The study quantified loss expansion factors for each segment of RMP's T&D system as shown in Figure 3 below. The loss expansion factors include both load and no-load losses.

[15] *Id.*

	Demand (MW)		Energy (MWh)	
Segment	Factor	Cumulative	Factor	Cumulative
1) Transmission System	1.04259	1.04259	1.04527	1.04527
2) Distribution Substation	1.00602	1.04887	1.00665	1.05222
3) Primary Line	1.02375	1.07377	1.01342	1.06635
4) Line Transformer	1.01586	1.09080	1.01863	1.08621
5) Secondary	1.00246	1.09348	1.00141	1.08774
6) Service Drop	1.00694	1.10106	1.00504	1.09322

Figure 3 – Loss Expansion Factors by RMP T&D System Segment[16]

Q. Please explain the loss expansion factors.

A. The loss expansion factors provide estimates of the demand (peak) and energy (average) system losses associated with the transmission and delivery of power to each voltage level over a designated period of time.[17]

Q. What can you conclude from RMP's loss analysis and the loss expansion factors shown in Figure 3?

A. Cumulative technical losses on RMP's system for energy delivered through the transmission system to the customer meter are 10.106% of demand and 9.322% of energy. Losses on the transmission system are 4.259% of demand and 4.527% of energy. Losses on the primary distribution system (including the distribution substation, primary line, and line transformer) are 4.624% of demand[18] and 3.917%

[16] *Id.* at Appendix B, Exhibit 9.
[17] *Id.* at 9.
[18] From Figure 3, the cumulative demand loss expansion factor at line transformers (1.09080) / the demand loss expansion factor of the transmission system (1.04259) = the demand loss expansion factor of the primary distribution system (1.04624).

of energy.[19] Cumulative losses from the transmission system through the primary distribution system are 9.080% of demand and 8.621% of energy.

3) <u>Reduced Losses and the Valuation of CG Exports</u>

Q. Please explain how CG exports reduce losses.

A. I previously explained how any excess power not required at a CG customer's home or business typically serves other customers connected to the same distribution line transformer (*i.e.*, via the secondary distribution system). These CG system exports reduce the need for centralized generation capacity and reduce the energy flowing on the transmission and primary distribution system, thus reducing losses.

Q. What are the appropriate loss expansion factors for reduced or avoided energy and generation capacity?

A. Because CG exports typically utilize the secondary and service segments of the distribution system, it is appropriate to consider the avoided cumulative losses from the transmission system through the primary distribution system up to and including line transformers. As shown in Figure 3, *supra* at line 224, these loss expansion factors are 1.09080 for demand and 1.08621 for energy.

Q. Are there other ways that CG exports impact losses?

[19] From Figure 3, the cumulative energy loss expansion factor at line transformers (1.08621) / the energy loss expansion factor of the transmission system (1.04527) = the energy loss expansion factor of the primary distribution system (1.03917).

A. Yes. I previously explained how CG exports contribute to the deferral or avoidance of distribution capacity additions. Dr. Yang will explain how CG exports can additionally contribute to the deferral of transmission capacity additions. Avoided distribution capacity additions avoid primary distribution system losses, with a loss expansion factor of 1.04624.[20] Avoided transmission capacity additions result in avoided transmission and primary distribution system losses, with a loss expansion factor of 1.09080.[21]

Q. Please summarize your recommendations for the valuation of CG exports with regard to avoided losses.

A. I recommend that the valuation of CG exports include the following loss expansion factors:

	Loss Expansion Factor	
Export Credit Component	Demand (MW)	Energy (MWh)
Avoided Energy		1.08621
Avoided Generation Capacity	1.09080	
Avoided Transmission Capacity	1.09080	
Avoided Distribution Capacity	1.04624	

Figure 4 – Loss Expansion Factors for the Valuation of CG Exports

4) <u>CG is Reducing Line Losses on RMP's System</u>

Q. What impact have the exports of RMP's customers with distributed generation had on reducing line losses?

[20] *See supra,* fn. 18.
[21] *See supra* at line 224.

A. RMP's customers with distributed generation exported 231,629 MWh of electricity in 2019.[22] I previously explained how CG exports typically serve the load of neighboring customers connected to the same distribution line transformer. This therefore means that 231,629 MWh of electricity did not flow through RMP's transmission, distribution substation, primary line, and line transformer segments. Applying the cumulative energy loss expansion factor at the line transformer of 1.08621 from Figure 3 results in 19,969 MWh of avoided technical losses from the CG exports in 2019.[23]

VI. RMP is not Incurring Significant CG Integration Costs

Q. Did you conduct a review of RMP's CG integration costs?

A. Yes. Vote Solar requested that I analyze if it may be appropriate to include an integration cost component in the valuation of CG exports.

Q. What information did you review in this analysis?

A. I reviewed the penetration level of CG in RMP's territory as well as information provided by RMP regarding distribution system investment in Docket Nos. 13-035-184 and 14-035-114.

Q. What is the penetration of CG in RMP's Utah service territory?

[22] Vote Solar, *Affirmative Testimony of Lee*, Exhibit 1-AJL, sum of values in column E.
[23] 231,629 x (1.08621 – 1) = 19,969

A. In 2019, the 314 MW_{DC} of CG capacity in RMP's Utah service territory produced 405,890 MWh.[24] With 2019 sales in Utah of 23,708,729 MWh,[25] this represents a CG penetration of 1.7% in RMP's Utah service territory.

Q. In your experience, are significant integration costs incurred at a CG penetration of 1.7%?

A. No. In my experience, typical distribution systems are very capable of accommodating CG penetrations at much higher levels than 1.7% before requiring significant investment.

Q. Has RMP claimed the need to invest in its distribution system due to CG?

A. Yes. In Docket No. 14-035-114, which led to this proceeding, RMP witness, Douglas L. Marx, claimed that "increasing levels of rooftop solar can actually force the Company to increase the local distribution system including distribution transformers, secondary cables, and service conductors to handle the excess generation."[26]

Q. Is this a credible claim?

[24] Lee, Exhibit 1-AJL, sum of values in column D.
[25] *2019 Integrated Resources Plan*, PacifiCorp, Volume II – Appendices A-L, Table A.12, p. 17, October 18, 2019, https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificorp/energy/integrated-resource-plan/2019_IRP_Volume_II_Appendices_A-L.pdf.
[26] Rocky Mountain Power, *Direct Testimony of Douglas L. Marx* ("Marx Testimony"), Docket No. 14-035-114, lines 57–60, Nov. 9, 2016, https://pscdocs.utah.gov/electric/14docs/14035114/290114DirTestMarx11-9-2016.pdf.

A. No. In response to Vote Solar discovery requesting details on these alleged costs to "increase the local distribution system," RMP provided the values in Figure 5 below.[27]

2015	2016	2017	2018	2019
$ 49,698	$ 375,991	$ 484,254	$ 724,116	$ 439,586

Figure 5 – RMP Gross Costs for CG Integration

In response to a follow-up discovery request, RMP acknowledged that these are "gross" costs and do not reflect offsetting customer contributions in aid of construction ("CIAC"). Additionally, RMP's follow-up response included the double counting of $244,026 in 2018 for a "Cust Generation Load Study."[28] Excluding CIAC, correcting for the double counting error, and excluding the costs of the load study, I show actual CG integration costs incurred by RMP in Figure 6 below.

	2015	2016	2017	2018	2019
Gross integration Costs	$ 49,698	$ 375,991	$ 484,254	$ 480,090	$ 439,586
CIAC	$ (70,332)	$ (312,301)	$ (448,326)	$ (185,974)	$ (382,725)
Cust Generation Load Study				$ (244,026)	$ (73,114)
Actual Integration Costs	$ (20,635)	$ 63,690	$ 35,928	$ 50,091	$ (16,253)

Figure 6 – RMP Actual Costs for CG Integration

Q. Has RMP further explained what is included in these integration costs?

[27] Exhibit 9-CV, *Responses to Vote Solar Data Request 6.8(3)*, RMP's Responses to Vote Solar 6th Set Data Requests (Aug. 16, 2019); Exhibit 10-CV, *Responses to Vote Solar Data Request 6.21(2)*, RMP's Responses to Vote Solar 6th Set Data Requests (Aug. 26, 2019) (referring to RMP Response to Vote Solar Data Request 6.8 subpart (3)).

[28] Exhibit 11-CV, Attach Vote Solar 7.3.xlsx, RMP's Responses to Vote Solar 7th Set Data Requests - Attach 7.3 (Oct. 10, 2019).

A. No. The spreadsheet provided by RMP with the alleged integration costs has mostly abbreviated and cryptic descriptions of the line items, such as "ACC" and "'/ R/R XFRMR." It is not possible to fully understand what is included in these costs without additional information.[29]

Q. Would these costs have a material impact on the CG export valuation if included?

A. No. I previously explained, *supra* at lines 287–88, that RMP's CG customers produced 405,890 MWh in 2019.[30] Assuming worst-case integration costs of $64,000 per year from Figure 6 translates to 0.016 cents per kWh. This is negligible.

Q. What do you recommend?

A. Even if RMP is able to demonstrate that its actual integration costs in Figure 6 are legitimate, the impact on CG valuation is negligible. The valuation of CG exports should exclude any integration costs claimed by RMP.

Q. What other claims has RMP made about the need for distribution system investment?

A. RMP witness, Mr. Marx, has also claimed: "If customers . . . (become) net zero-electric energy customers, the Company will need to increase the size of the local

[29] *Id.*
[30] Lee, Exhibit 1-AJL, sum of values in column D.

distribution system to handle the reverse energy flow delivered to the grid by the customers."[31]

Q. Is this a credible claim?

A. No. In response to a Vote Solar discovery request seeking evidence to support this statement, RMP directed us to a 2017 NEM Distribution Line Loss Study.[32] The study shows an increase in the average peak loading from [redacted] kW per customer of imports in the [redacted] scenario to [redacted] kW per customer of peak exports in the [redacted] scenario, a worst-case increase o[redacted] kW.[33]

As points of reference, a typical hair dryer on high heat will use around 1.5 kW.[34] A customer plugging in an electric vehicle ("EV") to a standard 120 V household outlet increases demand by 1.4 kW when charging. Adding a Level 2 (240 V) EV charger increases household demand by 6.2-7.6 kW when charging.[35]

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[31] *Marx Testimony*, lines 60–63.

[32] Exhibit 12-CV, NEM Distribution Line Loss Study BNG11 FINAL CONF.pdf, RMP's Responses to Vote Solar 6th Set Data Requests – Attach 6.21-1 CONF (Aug. 23, 2019). [redacted]

[33] Exhibit 13-CV, Attachment Vote Solar 7.4.pdf, RMP's Responses to Vote Solar 7th Set Data Requests – Attach 7.4 (Oct. 10, 2019) (Providing corrected table for p. 10, Table 5 of Exhibit 12-CV). Base Case Scenario: [redacted] kW / [redacted] customers = [redacted] kW per customer. Net Zero Scenario [redacted] kW / [redacted] customers = [redacted] kW per customer.

[34] *Electricity usage of a Hair Dryer*, Energy Use Calculator, http://energyusecalculator.com/electricity_hairdryer.htm.

[35] Doyle, Kevin, *Level Up Your EV Charging Knowledge*, Chargepoint, lhttps://www.chargepoint.com/blog/level-your-ev-charging-knowledge/.

RMP's distribution system is sufficiently sized and more than capable of handling CG exports, EV charging, and other increases in power flow.[36]

Q. Has RMP made changes to its design and construction standards following the NEM Distribution Line Loss Study?

A. No. In response to a Vote Solar data request, RMP acknowledges that it has taken no action to revise its design and construction standards in response to the results of the NEM Distribution Line Loss Study.[37]

Q. Has RMP made other claims of increased distribution system costs due to CG?

A. Yes. RMP Witness, Mr. Marx, also cited, as an example of increased distribution system costs, RMP's sister company, Pacific Power, having to replace distribution transformers to accommodate CG customers due to the absence of a primary neutral connection.[38]

[36] According to RMP's response to Vote Solar Data Request 7.4(10), the Company allows a maximum loading of 150 amps (17 kW at 120 V, 34 kW at 240 V assuming a 0.95 power factor) for its standard service cable. According to RMP's response to Vote Solar 7.4(8), the Company allows a maximum loading of 316 amps (36 kW at 120 V, 72 kW at 240 V assuming a 0.95 power factor) for its standard secondary cable. Exhibit 7-CV, *Response to Vote Solar Data Request 7.4(10) & 7.4(8),* RMP's Responses to Vote Solar 7th Set Data Requests (Oct. 10, 2019).
[37] *Id. RMP Response to Vote Solar Data Request 7.4(12)*.
[38] Rocky Mountain Power, *Rebuttal Testimony of Douglas L. Marx*, Docket No. 13-035-184, lines 134–38, June 26, 2014.

Q. Is this a credible and compelling example?

A. No. When pressed through discovery, RMP acknowledges this happened only once for Pacific Power.[39] RMP further acknowledges it has never experienced a similar incident.[40]

Q. What do you conclude?

A. I conclude that there is no evidence that RMP is incurring significant distribution costs to accommodate or integrate CG. The valuation of CG exports should exclude any integration costs claimed by RMP.

VII. Summary of Recommendations

Q. Please provide a summary of your recommendations.

A. I recommend that the valuation of CG exports:

1) Include a distribution deferral component based on a distribution capacity cost of [redacted] per kW and a utilization weighting of [redacted]%. Vote Solar witnesses, Drs. Berry and Yang, provide details of the methodology for including these components.

2) Include the following loss expansion factors:

[39] Exhibit 14-CV, *Response to Vote Solar Data Request 6.24(11),* RMP's Responses to Vote Solar 6th Set Data Requests (Aug. 23, 2019).
[40] *Id. Response to Vote Solar Data Request 6.24(14).*

Export Credit Component	Loss Expansion Factor Demand (MW)	 Energy (MWh)
Avoided Energy		1.08621
Avoided Generation Capacity	1.09080	
Avoided Transmission Capacity	1.09080	
Avoided Distribution Capacity	1.04624	

3) Exclude any alleged RMP distribution costs for CG integration.

I also recommend that the Commission consider exploring the lessons learned and best practices from other states in implementing Integrated Distribution Planning to reduce costs and increase the reliability and sustainability of the distribution grid.

Q. Does this conclude your testimony?

A. Yes.

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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