PACIFIC POWER
A DIVISION OF PACIFICORP

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July 26, 2018

VIA ELECTRONIC FILING

Public Utility Commission of Oregon
201 High Street SE, Suite 100
Salem, OR 97301-3398

Attn: Filing Center

RE: UM 1910 —PacifiCorp's Opening Brief

PacifiCorp d/b/a Pacific Power encloses for filing in the above-referenced docket its Opening Brief.

If you have questions about this filing, please contact Natasha Siores, Manager, Regulatory Affairs, at (503) 813-6853.

Sincerely,

Etta Lockey
Vice President, Regulation

Enclosure

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 1910

In the Matter of PACIFICORP, d/b/a PACIFIC POWER Resource Value of Solar	PACIFICORP'S OPENING BRIEF

I. INTRODUCTION & BACKGROUND

The Public Utility Commission of Oregon (Commission) opened this and two other proceedings in Order No. 17-357 as Phase II of the Commission's investigation into the resource value of solar (RVOS). Phase I, conducted in docket UM 1716, undertook to investigate a "comprehensive study into the resource value of solar"[1] by identifying the key elements and methodologies that comprise the value of solar as a resource.[2] Phase II seeks to implement these elements using utility-specific inputs.

This investigation was prompted by the Oregon Legislature in House Bill (HB) 2893,[3] which instructed the Commission to investigate and report on—among other things—solar's value as a resource.[4] The Commission has since sought to develop "a deep understanding" of how to accurately value solar, and to ultimately arrive at "the best available estimate or approach to developing an estimate of the resource value of solar."[5] At Staff's suggestion in docket UM 1716, the Commission retained an independent consultant, Energy and Environmental Economics, Inc. (E3), who proposed a dynamic framework using

[1] Order No. 15-296 at 2.
[2] Docket No. UM 1716, Order No. 16-404 at 1 (Oct. 19, 2016).
[3] HB 2893, 77th Or. Leg., 2013 Reg. Sess.
[4] HB 2893 Sec. 4.
[5] Order No. 15-296 at 2.

11 elements to calculate each utility's RVOS.[6] After robust public comment and review of the 11 elements, and other elements proposed for consideration by stakeholders, the Commission adopted the E3 methodology, with minor modifications. The Commission directed each regulated utility to open a separate docket and apply these 11 elements using utility-specific inputs and a "generic, small-scale solar resource installed in 2017."[7]

PacifiCorp, d/b/a Pacific Power supports the RVOS model developed by E3 as a flexible, transparent means of valuing a variety of resources, including solar.[8] Given that the RVOS may be applied to any number of programs and solar technologies, the method for calculating the RVOS must be flexible and dynamic, capable of customization for specific applications, and able to incorporate the most current information for each utility.[9] The company proposes only minor adjustments to more accurately reflect the value of solar to customers, and encourages the Commission to periodically verify the accuracy of the model by comparing its outputs against other reliable information sources such as integrated resource plans (IRPs) and request for proposals (RFPs).

II. DISCUSSION

A. Application of Elements

Consistent with the directives and guidance in Order No. 17-357, PacifiCorp calculated values for each of the 11 RVOS elements. To illustrate how the RVOS would apply to a "generic" resource, PacifiCorp created a composite RVOS resource based on a simple average of expected generation profiles for fixed-tilt solar projects from three

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[6] Docket No. UM 1716, Order No. 15-296 at 1-2 (Sep. 28, 2015).
[7] Order No. 17-357 at 1.
[8] Of the 11 elements, only administration, integration, and transmission and distribution (T&D) capacity reflect assumptions specifically tied to solar resources. The RVOS model could also differentiate among various Demand Side Management alternatives in valuable new ways.
[9] PAC/100, MacNeil/4.

different parts of the company's Oregon service territory: the Willamette Valley, southern Oregon, and central Oregon.[10]

PacifiCorp used this composite resource, along with its specific system and portfolio inputs, to develop an RVOS using E3's model workbook, with only slight modifications such as using a 12-month-by-24-hour (12x24) shape for transmission losses, reporting nominal levelized results, and adding inputs for both one-time and ongoing administrative costs.[11] Table 1 shows the 25-year nominal-levelized results by RVOS element for this resource, beginning in 2018. For comparison, results are shown based on the standard avoided cost (as ordered by the Commission), based on PacifiCorp's Partial Displacement Differential Revenue Requirement (PDDRR) methodology assuming displacement of a proxy simple cycle combustion turbine, and a utility-scale alternative based on the costs of proxy tracking solar resources in PacifiCorp's 2017 IRP Update.[12]

[10] PAC/100, MacNeil/3.
[11] PAC/100, MacNeil/5.
[12] PAC/100, MacNeil/3 and PAC/300, MacNeil/2.

Table 1: RVOS
$/megawatt-hour (MWh) Nominal Levelized (2018-2042)

Element	Standard: 2015 IRP	PDDRR: 2017 IRP	Utility-scale starting 2030
Avoided energy cost	30.58	33.63	
Avoided generation capacity cost	12.20	17.96	
Avoided T&D capacity	0.08	0.08	
Avoided line losses	1.96	2.14	
Administration	(2.88)	(2.88)	
Integration	(0.82)	(0.82)	
Market price response	0.15	0.00	
Avoided hedge value	1.54	1.68	
Avoided environmental compliance	0.11	0.22	
Avoided renewable portfolio standard (RPS) compliance	0.00	0.00	
Grid services	0.00	0.00	
Total RVOS (Nov. 2017)	**42.92**	**52.00**	
Updates and adjustments	+2.97	+2.24	
Total RVOS (April 2018)	**45.89**	**54.23**	**37.71**

As explained in more detail below, PacifiCorp's results reasonably reflect the RVOS for a composite Oregon solar resource and, to the extent PacifiCorp's application differs from E3's model workbook, these modifications only enhance the model's accuracy and further the Commission's goal of accurate, detailed valuation. The PDDRR and utility-scale results provide helpful reference points based on alternative proxy resource assumptions.

1. Energy (Element 1)

The energy element establishes the marginal cost of obtaining energy that a solar resource can effectively avoid.[13] To develop the avoided energy value, the Commission directed each utility to (1) use "the same pricing source used to develop average monthly or

[13] Order No. 17-357 at 21.

annual on and off-peak standard qualifying facility (QF) energy values," (2) use a 12x24 price shape, and (3) compare the results based on a range of hydro conditions.[14]

Consistent with the Commission's direction, the energy value in PacifiCorp's RVOS model reflects the monthly market prices from the Official Forward Price Curve (OFPC) used in the company's current, approved standard avoided costs.[15] Standard QF avoided energy values during the sufficiency period are based on a weighted blend of the forward prices for the Mid-Columbia, California-Oregon Border (COB), and Palo Verde markets.[16] During the deficiency period, standard QF avoided energy values are based on the variable costs of the same combined cycle combustion turbine (CCCT) used to set avoided generation capacity values.

The company then adjusted these monthly averages based on historical Energy Imbalance Market (EIM) values to create an hourly price shape, spreading the monthly forward prices over the 24 hours in each day. The average monthly energy value still reflects the forward market price rather than EIM prices, while using the hourly EIM data to establish the 12x24 price shape, shown below. As a result, EIM data is not the "sole" shaping factor, as Staff suggests.[17]

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[14] Order No. 17-357 at 4-5.
[15] PAC/100, MacNeil/7. PacifiCorp anticipates that it will have revised standard non-renewable avoided cost prices within the next few months. This update would impact the deficiency year, fixed costs of the proxy resource, the 12x24 loss of load probability (LOLP) pattern, and OFPC assumptions. However, updates to these inputs are not expected to impact the underlying RVOS methodology, and thus can be readily incorporated once revised avoided costs have been approved.
[16] PAC/100, MacNeil/6.
[17] Staff/100, Andrus/9.

Figure 1: RVOS Hourly Market Scalars for 2019

	Hour																								
Period	LLH						HLH																LLH		Avg
Month	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	
1	1.0	0.9	0.9	0.9	1.0	1.1	1.3	1.6	1.4	1.2	1.2	1.0	0.8	0.8	0.8	0.9	1.2	1.7	1.6	1.5	1.6	1.4	1.3	1.1	1.2
2	1.0	0.9	1.0	1.0	1.0	1.3	1.4	1.8	1.5	1.2	0.9	0.8	0.7	0.8	0.6	0.7	1.0	1.8	2.1	1.6	1.5	1.4	1.3	1.0	1.2
3	0.8	0.6	0.6	0.8	0.7	1.1	1.6	2.2	1.3	0.9	0.6	0.5	0.3	0.3	0.2	0.2	0.3	1.1	1.8	2.3	2.2	1.8	1.5	1.0	1.0
4	0.7	0.5	0.3	0.3	0.4	0.7	1.0	1.4	1.1	0.8	0.5	0.4	0.4	0.4	0.4	0.5	0.4	0.6	1.0	1.6	1.9	1.3	1.4	0.8	0.8
5	0.7	0.4	0.3	0.2	0.3	0.3	0.4	0.8	0.7	0.6	0.6	0.5	0.6	0.7	0.6	0.8	0.8	0.7	0.8	0.7	1.0	1.0	1.0	0.9	0.7
6	0.7	0.5	0.4	0.3	0.2	0.2	0.1	0.3	0.5	0.4	0.7	0.7	0.8	1.0	0.9	0.9	1.0	0.9	0.9	0.9	0.8	1.1	1.4	1.3	0.7
7	0.9	0.8	0.8	0.8	0.8	0.8	0.7	0.8	0.9	0.9	0.9	0.9	1.0	1.0	1.1	1.2	1.3	1.2	1.1	1.3	1.2	1.1	1.1	1.0	1.0
8	0.9	0.8	0.8	0.8	0.8	0.9	0.8	0.9	0.9	0.9	0.9	1.0	1.0	1.2	1.3	1.4	1.6	1.6	1.8	1.6	1.4	1.3	1.1	1.0	1.1
9	0.9	0.8	0.8	0.8	0.8	0.9	0.9	1.0	0.9	0.9	0.9	0.9	0.9	1.0	1.1	1.2	1.2	1.2	1.6	1.7	1.3	1.2	1.2	1.0	1.0
10	0.9	0.9	0.9	0.8	0.9	0.9	1.0	1.1	1.2	1.3	1.3	1.2	1.1	1.0	0.9	0.8	0.9	1.1	1.5	1.5	1.2	1.0	1.3	1.0	1.1
11	0.9	0.9	0.8	0.9	0.9	1.1	1.0	1.6	1.2	1.1	1.1	1.0	0.9	0.9	1.0	1.0	1.2	1.5	1.4	1.3	1.3	1.2	1.2	1.1	1.1
12	1.0	0.9	0.9	0.9	0.9	1.1	1.3	1.7	1.4	1.3	1.2	0.9	0.8	0.8	0.9	1.0	1.4	1.7	1.7	1.5	1.4	1.4	1.4	1.1	1.2
Avg	0.9	0.8	0.7	0.7	0.7	0.9	0.9	1.3	1.1	0.9	0.9	0.8	0.8	0.8	0.8	0.9	1.0	1.3	1.4	1.4	1.4	1.3	1.3	1.0	1.0

While this hourly shape is consistent with the Commission's direction to establish 12x24 pricing, it is important to recognize that simply averaging prices across each hour (rather than weighting the average price by quantity of production) actually overstates the average energy value of solar.[18] For instance, as solar resources ramp down in the late afternoon hours, the first portion of the hour has the greatest solar output and prices are correspondingly low. As solar output falls across the hour, prices increase as supply subsides. Using a simple average for all sales during this hour means that a large amount of solar is receiving an increased price, while a small amount of solar is receiving a decreased price—resulting in overpayment in total. PacifiCorp proposes using a *weighted* average price instead that would provide a single hourly value while accounting for fluctuations in solar production across the hour.

Staff has suggested that PacifiCorp should supplement its EIM data with other short-term wholesale market transactions to improve the hourly price shape.[19] However, the vast majority of PacifiCorp's short-term wholesale transactions span large blocks of hours, which

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[18] PAC/300, MacNeil/15.
[19] Staff/100, Andrus/9.

do not provide useful hourly price information.[20] In 2017, for example, only four percent of PacifiCorp's total short-term firm purchases were hourly transactions. Nor would these limited purchases enhance the hourly price shape, as such purchases are frequently conducted under atypical conditions, such as when wind or solar output is unexpectedly low. As a result, these short-term hourly transactions are not representative of typical hourly price shapes.

Oregon Solar Energy Industries Association (OSEIA) supports PacifiCorp's use of EIM data, but did not filter out outlier data,[21] which PacifiCorp removed by capping the EIM pricing results at -$50/MWh and $200/MWh. Prices this extreme are generally the result of unexpected conditions, such as a spike in load or a drop in variable generation.[22] For instance, in June 2017, EIM prices in PacifiCorp's western balancing area for a given hour included one 15-minute interval with prices of $1,000/MWh—whereas the average price for that period was $19/MWh. By including that single high interval, the average price would jump to $27/MWh. Such spikes are more akin to random outliers than meaningful information and, because they are not characteristic of any given hour, do not improve the hourly price shape and are appropriately excluded.[23]

Consistent with the Commission's direction, PacifiCorp also prepared additional analysis reflecting the impact of various hydro conditions. Given the limited efficacy and administrative costs of hydro modeling, PacifiCorp recommends that the Commission

[20] PAC/300, MacNeil/14.
[21] OSEIA/100, Beach/5.
[22] PAC/300, MacNeil/16.
[23] PAC/300, MacNeil/16.

remove this component from the RVOS energy element. Staff now appears to agree that the burdens of discrete hydro modeling outweigh any minor benefits achieved.[24]

To calculate the impact of a range of hydro conditions, PacifiCorp also prepared two additional forward price curves based on 'wet' and 'dry' conditions. Years within seven percent of the historical average hydro generation were designated as normal; years more than seven percent *above* the historical average were designated 'wet'; and years more than seven percent *below* the historical average were designated 'dry.'[25] PacifiCorp identified 1992 and 1999 as the dry and wet years, respectively, based on the hydro generation within the Pacific Northwest as reported by the Energy Information Administration.[26] PacifiCorp then reviewed the hydro conditions since 1990 to adjust the weighting of the wet and dry price curves.[27] During the historical period, 27 percent of the years were 'wet' years, while 38 percent were 'dry' years.[28] Wet years were typically less wet than 1999, while dry years were less dry than 1992. As a result, both curves were adjusted according to the degree of difference (percent deviation) from the 1999 and 1992 values.[29] This approach allowed the company to accurately weight the normal price curves to reflect typical 'wet' and 'dry' hydro conditions.[30]

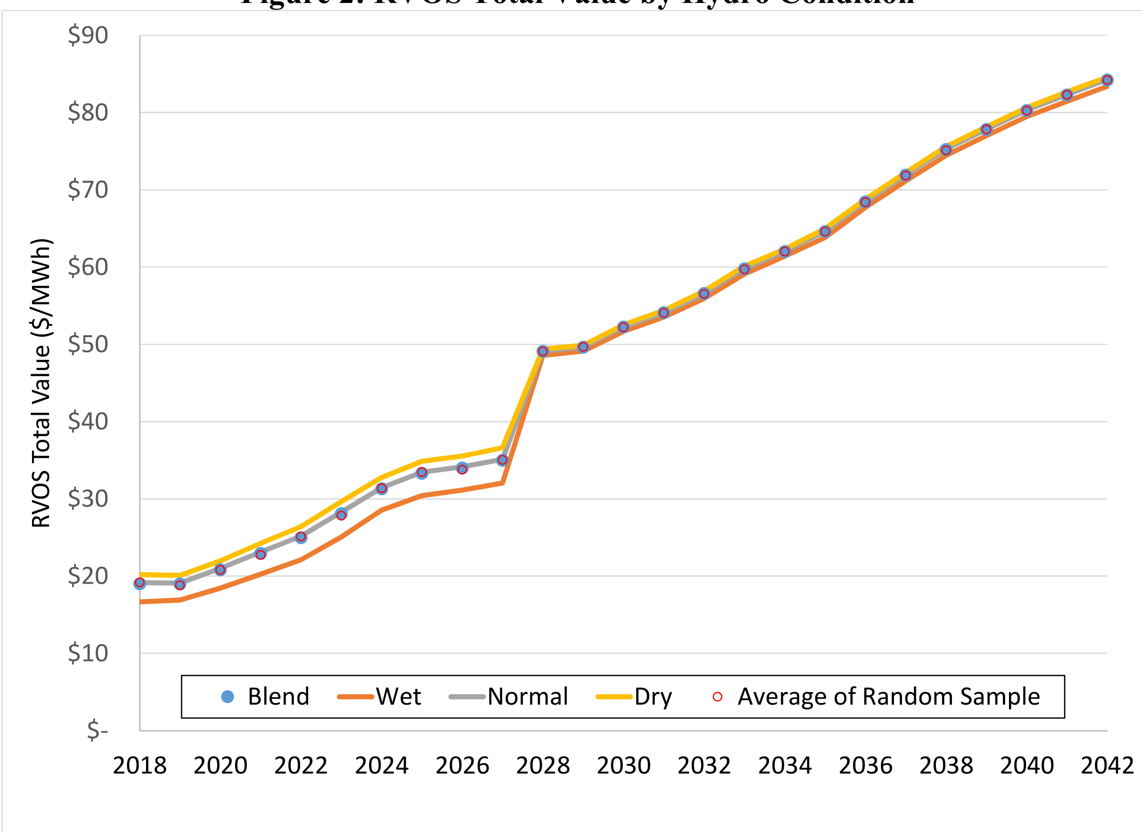
PacifiCorp's analysis demonstrated that hydro condition adjustments resulted in an average market price reduction of 0.8 percent at Mid-Columbia and 0.1 percent at COB, and an average market price increase of less than 0.1 percent at Palo Verde. There is no

[24] Pub. Util. Comm'n of Or., June 25, 2018 public meeting, Hearing Transcript at 62.
[25] PAC/100, MacNeil/8.
[26] PAC/100, MacNeil/9. Hydro generation in 1999 was 25 percent higher than the average for 1990 through 2015, while hydro generation in 1992 was 15 percent lower. PAC/100, MacNeil/9.
[27] PAC/100, MacNeil/10.
[28] PAC/100, MacNeil/10.
[29] PAC/100, MacNeil/10.
[30] PAC/100, MacNeil/10.

adjustment during the deficiency period, as avoided energy costs are not based on electricity market prices during that timeframe.[31]

At Staff's request, PacifiCorp also performed supplemental hydro analysis using a random sample of hydro years, creating a forward price curve for each year in the sample, and performing statistical analysis on the set of forward price curves.[32] The company created one hundred scenarios with random hydro conditions for each year during the 25-year RVOS study period, with the results shown in the figure below:

Figure 2: RVOS Total Value by Hydro Condition



This figure shows that, even under Staff's revised analysis, hydro conditions have a relatively small impact on RVOS energy prices. This minimal impact is because PacifiCorp's market

[31] PAC/100, MacNeil/11.
[32] PAC/300, MacNeil/18.

prices include the COB and Palo Verde markets, which are less affected by hydro conditions, and once energy prices switch to a CCCT resource in the deficiency period, any variation in energy prices reflects only minor seasonal shifts.

2. Generation Capacity (Element 2)

The capacity element seeks to measure the cost of building and maintaining the lowest net cost generation capacity resource that a solar resource might effectively avoid.[33] The Commission directed utilities to calculate a generation capacity value "in line with their current approved standard nonrenewable QF avoided cost capacity value."[34] The Commission added that it would "balance accuracy, transparency and accessibility" in reviewing alternate approaches.[35] PacifiCorp's RVOS model reflects avoided capacity costs consistent with its approved, standard avoided costs, currently based on the 2015 IRP.[36] This reflects capacity from market purchases through 2027 and capacity from a CCCT starting in 2028.[37]

Generation capacity value is also a function of a resource's capacity contribution. Because solar resources can include a range of generation profiles, a single capacity contribution value is unlikely to reasonably represent all solar resources that would be valued by the RVOS workbook.[38] PacifiCorp proposes determining the contribution value for a given solar resource based on the 12x24 LOLP results from the most recent IRP capacity contribution study, weighting the resource's capacity value based on the LOLP in each hour.

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[33] Order No. 17-357 at 21.
[34] Order No. 17-357 at 6.
[35] Order No. 17-357 at 6.
[36] Order No. 17-357 at 21.
[37] Note, while CUB initially proposed removing the sufficiency period from the RVOS calculation, CUB/100, Gehrke/5, it has since testified that its concerns have been met by the RVOS model. Pub. Util. Comm'n of Or., June 25, 2018 public meeting, Hearing Transcript at 52.
[38] PAC/100, MacNeil/20-21.

That is, a solar resource would receive a capacity contribution based on its expected output during those hours with LOLP greater than zero.[39] Under this approach, a resource delivering during all hours would have a 100 percent capacity contribution and 100 percent avoided capacity cost, as would a resource that only delivered in those hours in which LOLP was greater than zero.[40] This method effectively adjusts for the variable contribution of different types of solar as well as varying panel orientations.

In direct testimony, Staff stated that PacifiCorp's approach does not comply with the Commission's direction because it uses an hourly LOLP, rather than a fixed contribution to peak load factor.[41] However, PacifiCorp believes that this approach is both compliant and far more accurate by allowing for resource-specific contribution values and ensuring that resources are not compensated for capacity contributions that they do not provide.[42] At hearing, Staff agreed that PacifiCorp's approach is more accurate, albeit more complex.[43]

Staff and Renewable Northwest (RNW) proposed revising the RVOS resource sufficiency period to reflect the recently acknowledged 2017 IRP.[44] While the Commission has approved the company's 2017 IRP, the Commission directed utilities to "provide capacity value and timing (deficiency date) in line with their current approved standard-non-renewable QF avoided cost capacity value."[45] PacifiCorp filed updated standard QF pricing on July 20, 2018, with prices effective July 18, 2018, and July 24, 2018, for standard non-

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[39] PAC/100, MacNeil/21.
[40] PAC/100, MacNeil/21.
[41] Staff/200, Andrus/6-7.
[42] PAC/300, MacNeil/33; *see also* Order No. 17-357 at 6 ("Again, we will balance accuracy, transparency and accessibility in reviewing these alternative approaches.").
[43] Pub. Util. Comm'n of Or., June 25, 2018 public meeting, Hearing Transcript at 57.
[44] Staff/100, Andrus/20; RNW/100, O'Brien/10.
[45] Order No. 17-357 at 6.

renewable and standard renewable prices, respectively.[46] Due to the timing of this QF pricing update, PacifiCorp was not able to provide updated values as part of this proceeding. PacifiCorp intends to provide updated RVOS values incorporating the revised QF pricing along with any other modifications required following the Commission's final order in this proceeding.

OSEIA suggested including incremental capacity payments during the sufficiency period based on thermal operations and maintenance (O&M) expenses.[47] This is inappropriate, as energy value during the sufficiency period is based on market prices—for which no O&M is required—rather than PacifiCorp's marginal resource dispatch cost.[48]

OSEIA further proposes accelerating the deficiency period by four years, reasoning that utilities' large capacity resources may cause customers to pay for years of excess capacity until demand 'catches up' to the latest major addition.[49] This suggestion mistakenly assumes that large "lumpy" resources provide more capacity than PacifiCorp needs during its first year of operation. In the 2017 IRP preferred portfolio, the capacity from market transactions in 2029 is equal to the maximum available, indicating that the entire 200 megawatt (MW) resource is needed.[50] OSEIA acknowledged that market purchases may be relied on in this fashion for a number of years before a utility builds new plant, such that demand builds up over time.[51] Moreover, even if a portion of a large resource's capacity was not needed in the first year of the project's installation, that would simply imply that

[46] *In the Matter of PacifiCorp dba Pacific Power, Updates Standard Avoided Cost Purchases from Eligible Qualifying Facilities,* Docket No. UM 1729, Compliance Filing (Jul. 20, 2018). Note that the company's filing is subject to Staff review.
[47] OSEIA/100, Beach/10.
[48] PAC/300, MacNeil/26.
[49] OSEIA/100, Beach/7.
[50] PAC/300, MacNeil/27.
[51] Pub. Util. Comm'n of Or., June 25, 2018 public meeting, Hearing Transcript at 27.

customers' obligation to pay for a portion of the capacity provided by that resource could be deferred to a later date, not that customers should be obligated to pay for capacity *earlier* than the year of need as OSEIA proposes.[52]

3. T&D Capacity (Element 3)

The T&D element seeks to value the avoided or deferred costs of expanding, replacing, or upgrading T&D investments. The Commission directed utilities to develop a "system-wide average" of avoided or deferred costs attributable to incremental solar penetration, and noted that utilities "may continue to use" their Marginal Cost of Service Studies in the first version of the RVOS.[53]

PacifiCorp calculated its system-wide average T&D deferral values based on forecasted capacity additions and the costs of those projects.[54] To determine the amount of T&D capacity solar resources could avoid or defer, PacifiCorp considered whether any of the 33 transmission upgrade projects currently in the planning stages in Oregon (and with in-service dates after 2018) could be deferred by additional solar resources.[55] PacifiCorp similarly divided the capacity of distribution projects deferrable by solar by the total distribution capacity additions in Oregon, creating a system-wide average for avoidable distribution costs.[56]

OSEIA urges the Commission to use an alternative regression analysis based on system-wide load growth.[57] However, this approach fails to exclude non-deferrable T&D investments that only incidentally increase T&D capacity or do not increase T&D capacity at

[52] PAC/300, MacNeil/27.
[53] Order No. 17-357 at 9.
[54] PAC/201, Putnam/1.
[55] PAC/200, Putnam/3.
[56] PAC/400, Putnam/3.
[57] OSEIA/100, Beach 23.

all. OSEIA's value for T&D deferrals includes those investments that PacifiCorp would be obligated to pursue for reliability reasons, and that are therefore not avoidable by additional solar penetration.[58] As a result, OSEIA's approach does not comply with the Commission's direction to value only avoided or deferred costs attributable to incremental solar penetration.[59]

By comparison, PacifiCorp's analysis incorporates all anticipated and actually deferrable investments, extrapolated to provide a system-wide value. This approach very likely over-values deferrable T&D across the company's system, as it extrapolates from areas of known investment need to the utility's system generally. Relying on actual anticipated investments remains the most accurate approach to identifying T&D investments that distributed solar could defer. This avoided T&D value could continue to be improved by factoring in the remaining 258 substation transformers that do not have a capacity need, which would be projected to reduce the avoided T&D value overall.[60]

OSEIA also proposes including a 7.9 percent addition for T&D-related O&M costs, arguing that solar resources could effectively defer these costs along with avoided capacity.[61] But the vast majority of O&M and general plant costs are not avoidable, as they include basic maintenance costs, costs associated with items such as company trucks and computers, and other non-avoidable costs such as responding to downed distribution wires and performing associated repairs.[62]

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[58] PAC/400, Putnam/3.
[59] Order No. 17-357 at 9.
[60] PAC/400, Putnam/5-6.
[61] OSEIA/100, Beach/24.
[62] PAC/400, Putnam/5.

While PacifiCorp provided, per the Commission's direction, a system-wide average value for T&D deferral, the company proposes using substation-level data to better localize T&D deferral values. Additionally, once a particular T&D investment has been fully avoided, T&D deferral values should be updated such that additional solar resources do not receive credit for avoiding the same T&D investment twice.[63] Taken together, these next steps would ensure that solar is able to truly avoid T&D investments, while also ensuring that solar's value is not double-counted.

4. Line Losses (Element 4)

This element seeks to determine the value of line losses that distributed solar can avoid.[64] The Commission directed utilities to develop hourly averages of avoided marginal losses, reflecting the hours solar photovoltaic (PV) systems generate energy.[65]

PacifiCorp began by calculating avoided line losses using the company's most recent line loss study from 2009, identifying both primary and secondary seasonal values, adjusted to create a monthly and hourly price shape reflecting a typical Oregon load profile.[66] Because line loss benefits are highest when generation is offsetting local load, PacifiCorp's line loss element can be adjusted to reflect whether (1) output is fully used behind the meter, (2) exported to the secondary distribution system, (3) exported to the primary distribution system, or (4) exported to the transmission system. Resources would then receive credit for avoided line losses based on those portions of the system not tasked to carry load, and where line losses are thus avoided.[67]

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[63] PAC/200, Putnam/3.
[64] Order No. 17-357 at 22.
[65] Order No. 17-357 at 22.
[66] PAC/200, Putnam/9; *see also* PAC/400, Putnam/12.
[67] PAC/200, Putnam/10.

PacifiCorp subsequently revised its calculation to use the results from its power flow studies, which account for the marginal loss by load level.[68] This value was then fitted to a 12x24 profile for resources connected at either the primary or secondary voltage levels.[69] The results are included in Figure 3, below, showing PacifiCorp's initial calculation ("As Filed"), as well as the revised approach ("Proposed Marginal"). The company's revised approach closely aligns with the marginal losses calculated using the 2009 line loss study, and is similar to twice the resistive losses calculated from the 2009 study.[70] As described in the Regulatory Assistance Project's 2011 report,[71] cited by OSEIA,[72] both of these benchmarks confirm the accuracy of PacifiCorp's revised analysis by accounting for the increased value of avoided line losses as load increases.[73]

OSEIA argues that the Commission should instead apply a 1.5 multiplier for average line losses, to account for the fact that marginal losses are lower at low loads than the 1.5 multiplier and higher at high loads.[74] But, as demonstrated in the chart below, applying this multiplier would actually reduce the value of avoided line losses at peak load while overstating the value at lower load factors.

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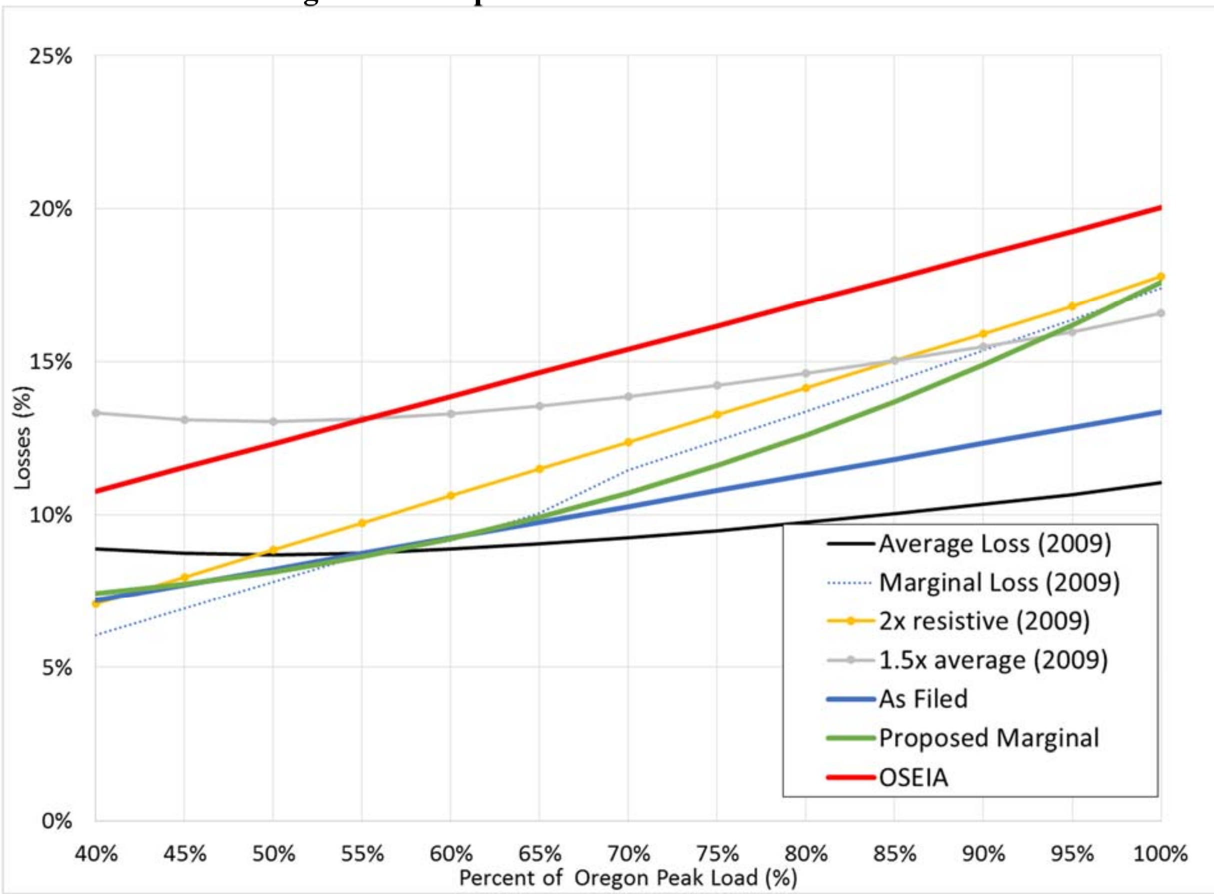
[68] PAC/400, Putnam/12.
[69] PAC/400, Putnam/12.
[70] PAC/400, Putnam/12.
[71] Regulatory Assistance Project, *Valuing the Contribution of Energy Efficiency to Avoided Marginal Line Losses and Reserve Requirements* at 5 (Aug. 2011) (RAP 2011 Report) (noting that marginal losses are roughly two times resistive losses).
[72] OSEIA/100, Beach/26.
[73] RAP 2011 Report at 4.
[74] OSEIA/100, Beach/25-26. Staff neither supported nor opposed OSEIA's approach, stating that the proposal "needs further review." Staff/300, Andrus/14.

Figure 3: Comparison of Line Loss Calculations



PacifiCorp's method reasonably recognizes the variation of line losses with respect to seasonality, time of day, and peak load, while distinguishing between resources connected at various points on PacifiCorp's system. Further granularity is not necessary at this time, as the administrative burden necessary to calculate and administer location-specific line losses would substantially outweigh the impact of any such analysis.[75]

5. Administration (Element 5)

The Commission directed utilities to propose estimates of direct, increased utility costs of administering solar PV programs, including justification for the method and value.[76] PacifiCorp arrived at likely administrative costs by calculating three basic components (1)

[75] PAC/200, Putnam/10.
[76] Order No. 17-357 at 10.

the incremental unrecovered administrative and engineering costs associated with processing customer participation requests, (2) the ongoing administration costs for customer service and billing of net metering customers that exceed those costs associated with traditional customers, and (3) the increase in distribution investments required to facilitate interconnection, to the extent these additional investments are not recovered from the interconnecting customers directly.[77] Parties have not identified any issues related to PacifiCorp's administration cost factor.[78]

6. Integration (Element 6)

The Commission directed utilities to calculate the costs of holding additional reserves in order to accommodate the fluctuations related to increased solar penetration.[79] PacifiCorp's integration costs are derived from the company's Flexible Reserve Study from the 2017 IRP, which considered the integration costs associated with various flexible resources, including solar.[80] Parties have not identified any issues related to PacifiCorp's calculation of the integration element.

7. Market Price Response (Element 7)

The market price response (MPR) element attempts to determine the change in utility costs due to the impact of solar on wholesale market prices, on the theory that increased quantities of low-cost solar resources will drive down market prices.[81] PacifiCorp's RVOS model accounts for the expected impact of RVOS resources on market prices and the changes in costs for PacifiCorp's forecasted volumes of short-term purchases and sales. Initially,

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[77] PAC/100, MacNeil/27.
[78] In response to a data request from CUB, PacifiCorp identified a correction to the administration cost value, which reduced the real-levelized cost of this component by 10 percent. *See* PAC/300, MacNeil/2. This correction has been incorporated into PacifiCorp's RVOS calculation. PAC/300, MacNeil/3.
[79] Order No. 17-357 at 22.
[80] PAC/100, MacNeil/31.
[81] Order No. 17-357 at 11.

PacifiCorp calculated the MPR outside the RVOS model,[82] but in response to Staff's concerns, market price response is now included as a separate component of PacifiCorp's RVOS calculation.[83]

PacifiCorp's calculation of MPR reflects the potential for both a positive and negative impact. During periods when PacifiCorp is a net seller in the market, the impact of solar is downward pressure on market prices that results in a cost to the company, whereas when PacifiCorp is a net purchaser, this downward pressure is a benefit to the company. As shown in Figure 4, below, PacifiCorp starts out with a long market position (net sales) and transitions to a short position (net purchases) over time. Yet the MPR value drops to zero during the deficiency period because the solar resource output is negated by the lost output of the avoided generation capacity resource.[84]

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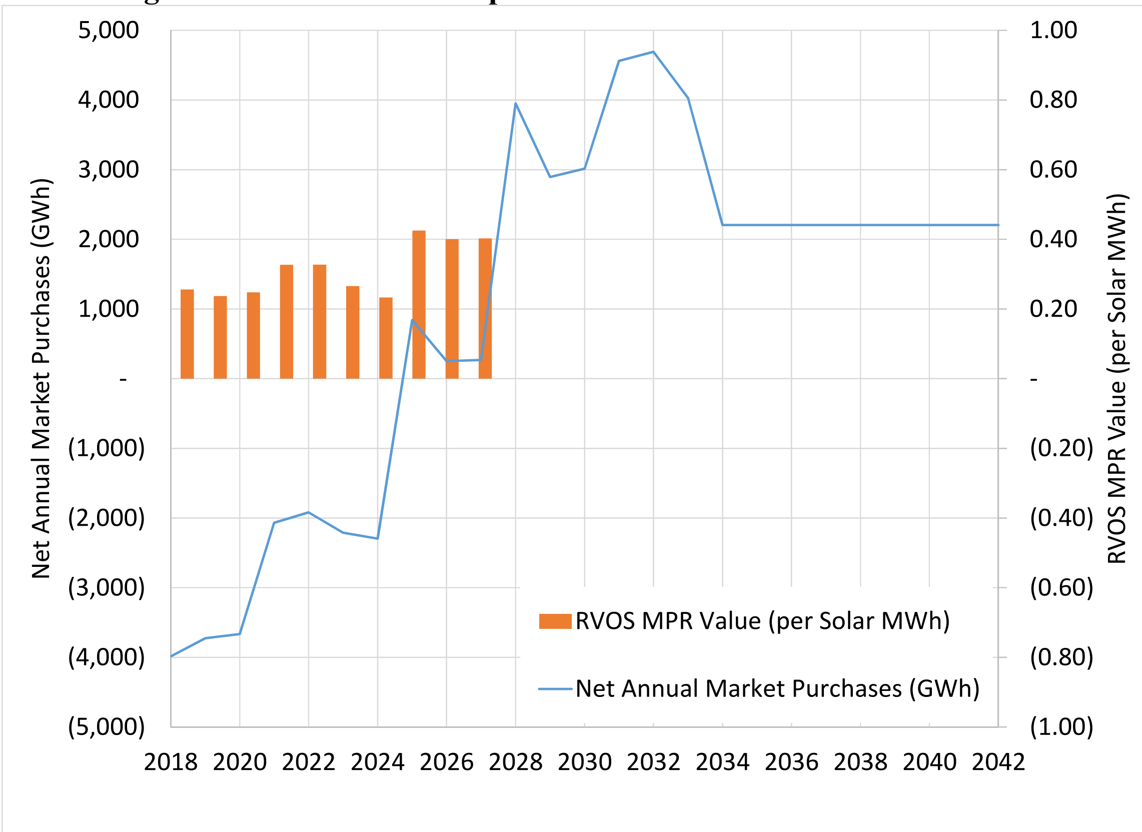
[82] PAC/300, MacNeil/20 (noting that Staff objected "to PacifiCorp's calculation of [MPR] outside the RVOS model").
[83] Staff/100, Andrus/53.
[84] PAC/300, MacNeil/22.

Figure 4: Market Price Response RVOS Value and Market Position



As a result, the MPR element has little impact on the RVOS. While OSEIA mistakenly states that PacifiCorp used a zero MPR value,[85] this is incorrect, as PacifiCorp's calculation provided a real levelized value of $0.15/MWh.[86]

A downward impact on market prices would also reduce the energy value of the RVOS, which is tied to market costs during the sufficiency period. While Staff agrees that there is some risk of "double-counting" the benefits of solar, Staff mistakenly believes that PacifiCorp assumed impacts on the MPR and energy elements would be equal and opposite, and recommends that the adjustments be calculated more precisely.[87] To the extent that

[85] OSEIA/100, Beach/29-30.
[86] PAC/300, MacNeil/21.
[87] Staff/200, Andrus/13.

increased solar penetration causes market prices to decrease, solar is avoiding lower-cost market purchases.

Staff also claims incorrectly that PacifiCorp's MPR value reflects only a single year.[88] PacifiCorp calculated a market price response for every year of the study period for each of the three major markets that comprise the avoided energy costs in standard QF rates and the RVOS model, shown in Figure 4 above.

OSEIA argues that PacifiCorp should use Portland General Electric (PGE) MPR value of 3.8 percent of avoided energy costs.[89] This is inappropriate, as the value from the MPR element is directly tied to a utility's long or short market position and the markets in which it transacts.[90] PacifiCorp's market position varies over the course of the year and across various, widely distributed markets. The values calculated for PGE do not accurately reflect this element's value to PacifiCorp.[91]

The MPR element does not improve the accuracy of avoided energy costs as it fails to account for the impacts of executed or potential PacifiCorp solar contracts or other regional solar capacity additions which would vastly outweigh the impact of the Oregon distributed solar resource additions contemplated in this proceeding.[92] As an administratively burdensome element with minimal impact on accuracy, PacifiCorp recommends removing this element from the RVOS calculation.

[88] Staff/100, Andrus/53-55.
[89] OSEIA/100, Beach/29.
[90] PAC/300, MacNeil/24.
[91] PAC/300, MacNeil/24.
[92] PAC/100, MacNeil/34 and PAC/300, MacNeil/24.

8. Hedge Value (Element 8)

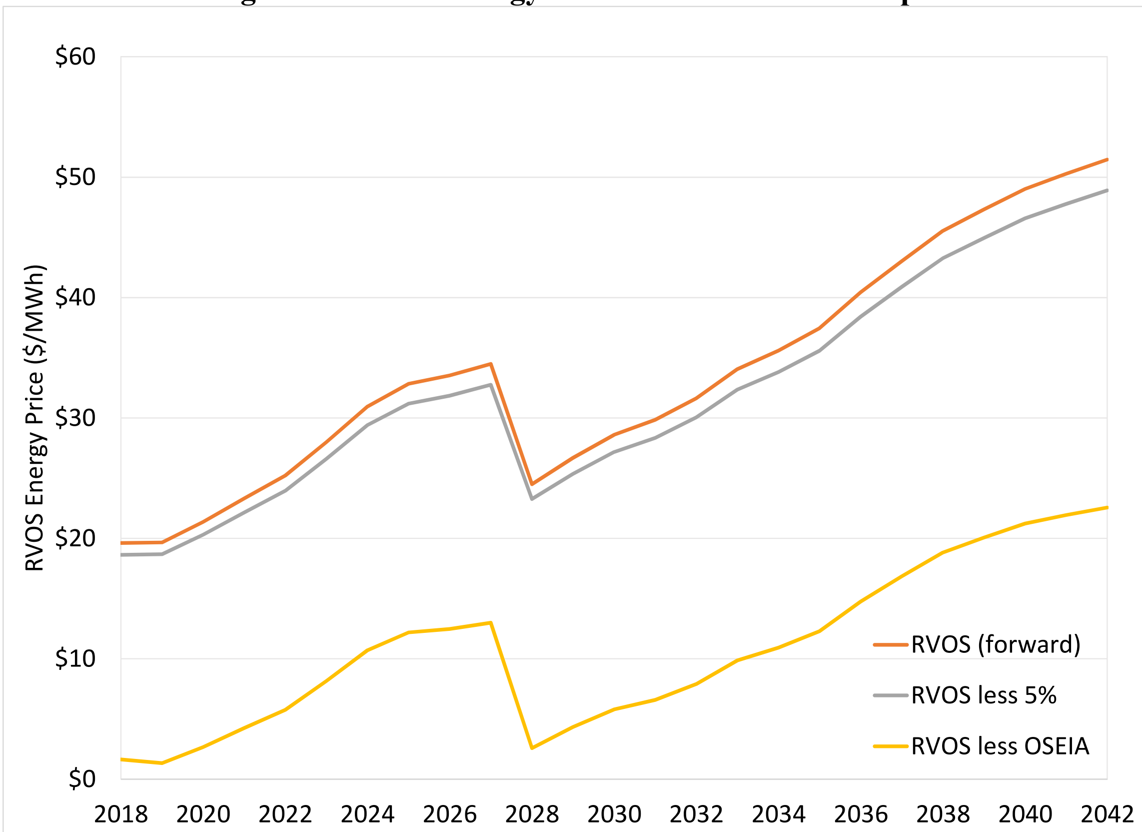
The hedge value element represents the value to the utility of avoiding the cost of hedging by providing "a more stable retail rate over time."[93] The Commission directed utilities to assign a proxy value of five percent of energy because, while the Commission was persuaded that "there is some value to this element," it also agreed with E3 that "the effort required to calculate hedge value at this time would outweigh its value."[94]

PacifiCorp used the five percent hedge value as directed by the Commission, resulting in $1.84/MWh on a 25-year nominal levelized basis.[95] However, this value results in a double-count of the hedging contribution of solar because the energy price element already reflects forward electricity market prices, which include a hedging value. Thus, the appropriate avoided hedge value in the RVOS is zero.

OSEIA urges the Commission to adopt alternative hedging values from a 2015 Maine study that massively overestimate the risk premium associated with forward prices, as shown in Figure 5, below.

[93] Order No. 17-357 at 22.
[94] Order No. 17-357 at 12.
[95] PAC/100, MacNeil/35.

Figure 5: RVOS Energy Prices: Forward Versus Spot



As this figure shows, OSEIA's approach assumes that the bulk of a forward market purchase is a risk premium, which is an enormous value for an implied risk premium.[96] Staff further notes that the study supporting OSEIA's proposal relies on "mere guesses" of long-term natural gas price forecasts; Staff continues to support the use of a five percent proxy hedge value.[97]

While the premise of a risk premium may be valid, its inclusion in the RVOS overlooks the fact that any such value is already incorporated by using forward market purchases as the basis for assessing avoided energy values.[98] As a result, PacifiCorp continues to urge the Commission to reduce this RVOS element to zero.

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[96] PAC/300, MacNeil/37.
[97] Staff/300, Andrus/18-20.
[98] PAC/300, MacNeil/38.

9. Environmental Compliance (Element 9)

The Environmental Compliance element seeks to credit solar with the costs of complying with existing and anticipated environmental standards, where those costs could be avoided by increased solar.[99] The Commission directed each utility to estimate a value for this element "based on a reduction in carbon emissions from the marginal generating unit," using "the carbon regulation assumptions from their IRP."[100] Thus, the avoided environmental compliance value reflects the price and quantity of avoided carbon dioxide (CO_2) emissions.

To calculate its avoided environmental compliance costs, PacifiCorp used the environmental compliance scenarios from its 2017 IRP, which included constraints related to the Environmental Protection Agency's Clean Power Plan (CPP).[101] In the first scenario (Mass Cap A), the proxy plant used to set standard avoided costs would not be subject to emissions limits, so there would be no avoided environmental compliance costs in the deficiency period.[102] In the second scenario (Mass Cap B), a possible fixed limit on emissions results in "shadow" prices for CO_2 around $6 per ton from 2024 through 2028. Beginning in 2029, planned coal retirements and renewable resource additions reduce emissions below the Mass Cap B threshold, dropping the shadow price to zero.[103] No environmental compliance costs apply to the sufficiency period, as market purchases have no assumed CO_2 emissions.[104] Because the deficiency period starts in 2028, while emissions would drop below the Mass Cap B threshold in 2029, compliance costs would only be

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[99] Order No. 17-357 at 23.
[100] Order No. 17-357 at 23.
[101] PAC/100, MacNeil/36.
[102] PAC/100, MacNeil/36.
[103] PAC/100, MacNeil/36.
[104] PAC/300, MacNeil/40.

incurred during 2028. This calculation resulted in an estimated avoided compliance cost of $0.11/MWh on a 25-year nominal levelized basis.[105]

PacifiCorp also developed an alternative value for avoided environmental compliance reflecting the PDDRR methodology.[106] This method differs from the standard avoided cost methodology by identifying a range of avoided resources, rather than assuming a one-to-one relationship between RVOS resource output and a single proxy resource.[107] As a result, this methodology accounts for PacifiCorp's entire portfolio of resources, and results in emissions forecasted to exceed the Mass Cab B annual limits in 2024 and 2027, resulting in avoided environmental compliance values of $2.09/MWh and $1.82/MWh, respectively, in those years.[108] On a nominal levelized basis, this PDDRR approach yields a slightly higher nominal levelized value of $0.22/MWh.[109]

Staff expressed concern that PacifiCorp estimated environmental compliance based on the CPP requirements in light of the anticipated repeal of the CPP.[110] While Staff asked the company to utilize its PDDRR approach for the environmental compliance element, it asked PacifiCorp to reassess the avoided compliance costs using CO_2 prices from a different sensitivity study in the 2017 IRP.[111] PacifiCorp has since updated its RVOS model to incorporate Staff's CO_2 pricing recommendations as possible future compliance scenarios.[112] Under the CO_2 prices proposed by Staff, environmental compliance costs would be avoided

[105] PAC/100, MacNeil/38.
[106] PAC/100, MacNeil/37.
[107] PAC/100, MacNeil/37.
[108] PAC/100, MacNeil/37.
[109] PAC/100, MacNeil/38.
[110] Staff/200, Andrus/15.
[111] Staff/200, Andrus/15.
[112] PAC/300, MacNeil/39.

beginning in 2025.[113] Staff expressed no further concerns on this element in its cross-reply testimony.[114]

PacifiCorp does not agree with Staff that the PDDRR approach should be used to assess avoided environmental compliance costs, but not avoided energy and generation capacity values.[115] The avoided environmental compliance costs associated with dispatching thermal resources under the PDDRR approach is only appropriate if energy prices also reflect the marginal cost of those resources (as compared to the higher cost of market transactions).[116] It is not reasonable to pair the higher avoided environmental costs associated with a thermal resource with the higher energy and capacity costs of market transactions, which would not entail avoided environmental compliance costs.

OSEIA proposed an alternate method for calculating avoided emissions, based on the environmental compliance costs for a natural gas fired resource with a 7,500 British thermal unit (Btu) per kilowatt-hour (kWh) heat rate.[117] It is unclear why avoided environmental compliance costs should be based on this specific gas resource, as opposed to PacifiCorp's own proxy resource, which has a heat rate of 6,530 Btu per kWh.[118] OSEIA also proposed using a uniform carbon compliance cost for all utilities, based on PGE's values.[119] Again, given the disparate portfolios and costs associated with environmental compliance among the utilities, it is not clear why a uniform value is preferable to a utility-specific calculation.

While PacifiCorp complied with the Commission's direction to develop a placeholder value of avoided environmental compliance for informational purposes, the company

[113] PAC/300, MacNeil/39.
[114] Staff/300, Andrus/16.
[115] PAC/300, MacNeil/41.
[116] PAC/300, MacNeil/41.
[117] OSEIA/100, Beach/35.
[118] PAC/300, MacNeil/41.
[119] OSEIA/100, Beach/34.

continues to believe that avoided environmental compliance costs are not a reasonable RVOS element at this time. PacifiCorp does not currently face any environmental compliance obligations that could be avoided with the addition of solar. The CPP was also repealed on October 10, 2017, and it is unclear whether the addition of solar resources in the future will avoid compliance costs to the benefit of other customers.[120]

10. RPS Compliance (Element 10)

The RPS compliance element reflects the cost to comply with Oregon's RPS, where that cost could be prevented by additional solar.[121] The Commission directed utilities to use a placeholder value of zero, with the application of this element to be considered later in Phase II.[122]

An RPS compliance value may be appropriate if a resource results in the company receiving a renewable energy credit (REC) that will be used for RPS compliance, or if a resource is used behind-the-meter to reduce a customer's load (lowering the overall RPS obligation).[123] However, PacifiCorp currently anticipates no incremental costs for RPS compliance until 2035, and the preferred portfolios in PacifiCorp's 2017 IRP and 2017 IRP Update included significant new RPS-eligible resources as part of the least-cost, least-risk portfolio without accounting for their RPS compliance benefits. As a result, the cost of RPS compliance associated with these resources is zero, or negative relative to other non-RPS eligible options. PacifiCorp's overall RPS compliance costs are thus likely to be low or negligible.

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[120] PAC/100, MacNeil/38.
[121] Order No. 17-457 at 23.
[122] Order No. 17-457 at 13-14.
[123] PAC/300, MacNeil/43 (explaining that removing one MWh of customer load would reduce the quantity of RECs necessary for RPS compliance by 0.35 MWh).

Staff recommended valuing the RPS compliance element according to the $/MWh from utilities' renewable portfolio compliance reports.[124] This approach does not consider the *incremental* cost associated with acquiring RPS resources, and further assumes that resources satisfying RPS compliance were higher cost than non-RPS qualifying resources. Where an RPS compliant resource was acquired as the least-cost, least-risk option, there is no increased cost associated with RPS compliance that solar could avoid.

Given that long-term RPS compliance remains an open issue where least-cost, least-risk resources meet utilities' RPS needs, the avoided cost compliance element should continue to be zero.

11. Grid Services (Element 11)

The Grid Services element is a placeholder that could "capture the potential incremental system benefits from solar in the future."[125] The Commission invited RNW or other parties "to make a proposal for valuing enabled smart inverters based on best practices or other utility experiences, and how the utilities could capture this value."[126] In accordance with the Commission's direction, PacifiCorp used a placeholder value of zero for the grid services element of the RVOS.

OSEIA suggested that storage combined with solar could provide a wide variety of grid services, including voltage support, regulation, and load following.[127] ODOE similarly highlighted the possible benefits of storage systems, as well as advanced technologies such as smart inverters.[128] While PacifiCorp agrees that the RVOS could effectively value solar,

[124] Staff/100, Andrus/53.
[125] Order No. 17-357 at 16.
[126] Order No. 17-357 at 16.
[127] OSEIA/100, Beach/43.
[128] ODOE/100, DelMar/4.

storage, and solar/storage combinations, any grid service benefits of storage depend on the utility's ability to dispatch the resource as needed.[129] PacifiCorp does not currently have programs and systems that would provide these elements, but recognizes that significant potential may exist.[130] PacifiCorp recommends considering all storage systems as the RVOS develops.

B. Utility-Scale Proxy

The Commissioner directed utilities to create a "utility scale proxy" to serve as a reference point only.[131] The utility-scale alternative uses the E3 workbook, replacing all elements but T&D capacity, administration, and line losses.[132] PacifiCorp calculated the utility-scale alternative using the current PDDRR methodology approved for calculating avoided cost prices for qualifying facilities in Oregon of up to 80 MW.[133] While no party objected to PacifiCorp's calculation of the utility-scale proxy, OSEIA argues that, relative to utility-scale solar resources, distributed sources should be credited with reduced land use impacts, increased customer choice, and enhanced reliability and resiliency of electric service when paired with on-site storage.[134] However, these additional benefits flow to participating customers (or potentially non-customers, in the case of land use impacts), and do not reduce utility costs or, by extension, the costs to non-participating customers. As a result, including these values would inappropriately shift costs from participating customers to non-participating customers.

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[129] PAC/300, MacNeil/45.
[130] PAC/300, MacNeil/45.
[131] Order No. 17-357 at 18.
[132] Order No. 17-357 at 18.
[133] PAC/300, MacNeil/47.
[134] OSEIA/100, Beach/40-41.

C. Updating the RVOS

To the extent energy or generation capacity inputs are tied to the standard avoided costs, PacifiCorp supports updating the RVOS calculation, whenever standard avoided cost prices are updated.[135] Frequent updates ensure that the RVOS is accurate and fair to all customers. This update schedule is consistent with the recommendations of other parties and of Staff.

In addition, PacifiCorp suggests comparing RVOS results to actual solar values from other processes, such as those in PacifiCorp's 2017 IRP Update, recent solar RFPs, and standard and non-standard avoided costs. These comparisons may help to verify the accuracy and reliability of RVOS calculations.

III. CONCLUSION

PacifiCorp understands that the Commission wishes to develop a more complete understanding of the value that additional solar penetration can provide, while ensuring that costs associated with new solar resources are not shifted to other utility customers. The E3 model, as implemented and modified above, can provide a reasonable estimate of the value of various resources, including solar. PacifiCorp appreciates the opportunity to continue working with the Commission and other parties to further refine the RVOS valuation.

[135] PAC/100, MacNeil/19.

Respectfully submitted this 26th day of July, 2018, on behalf of PacifiCorp.

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