PACIFIC POWER
A DIVISION OF PACIFICORP

825 NE Multnomah, Suite 2000
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November 30, 2017

VIA ELECTRONIC FILING AND HUDDLE

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

Attn: Filing Center

Re: UM 1910 – PacifiCorp's Resource Value of Solar Filing

In compliance with Public Utility Commission of Oregon Order No. 17-357, PacifiCorp d/b/a Pacific Power hereby submits its Resource Value of Solar filing, supported by the direct testimony of PacifiCorp witnesses Daniel J. MacNeil and Kevin C. Putnam.

Electronic workpapers will be posted to Huddle. Confidential material in support of this filing is provided under Order No. 17-483.

PacifiCorp respectfully requests that all communications related to this filing be addressed to:

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Additionally, PacifiCorp requests that all data requests regarding this matter be addressed to:

By e-mail (preferred):	datarequest@pacificorp.com
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Please direct informal correspondence and questions regarding this filing to Natasha Siores, Manager, Regulatory Affairs, at (503) 813-6583.

Sincerely,

Etta Lockey
Vice President, Regulation

Enclosures

CERTIFICATE OF SERVICE

I certify that I served a true and correct copy of PacifiCorp's Direct Testimony in docket UM 1910 on the parties listed below via electronic mail in compliance with OAR 860-001-0180.

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Dated November 30, 2017.

Jennifer Angell
Jennifer Angell
Supervisor, Regulatory Operations

Docket No. UM 1910
Exhibit PAC/100
Witness: Daniel J MacNeil

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Direct Testimony of Daniel J. MacNeil

November 2017

DIRECT TESTIMONY OF DANIEL J. MACNEIL
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Q. Please state your name, business address, and present position with PacifiCorp d/b/a Pacific Power.

A. My name is Daniel J. MacNeil. My business address is 825 NE Multnomah Street, Suite 600, Portland, Oregon 97232. My title is Resource and Commercial Strategy Adviser.

QUALIFICATIONS

Q. Briefly describe your education and professional experience.

A. I received a Master of Arts degree in International Science and Technology Policy from George Washington University and a Bachelor of Science degree in Materials Science and Engineering from Johns Hopkins University. Before joining PacifiCorp, I completed internships with the U.S. Department of Energy's Office of Policy and International Affairs and the World Resources Institute's Green Power Market Development Group. I have been employed by PacifiCorp since 2008, first as a member of the Net Power Costs group, then as manager of that group from June 2015 until September 2016. In my current role, I provide analytical expertise on a broad range of topics related to PacifiCorp's resource portfolio and obligations.

PURPOSE AND SUMMARY OF TESTIMONY

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

A. My testimony explains the inputs in the resource value of solar (RVOS) methodology as directed by the Public Utility Commission of Oregon (Commission) in Order No. 17-357. Specifically, I address the following elements:

1. Avoided energy cost;
2. Avoided generation capacity cost;

3. Avoided Transmission and Distribution Capacity;
4. Avoided Line Losses;
5. Administration;
6. Integration;
7. Market Price Response;
8. Avoided hedge value;
9. Avoided environmental compliance;
10. Avoided renewable portfolio standard (RPS) compliance; and
11. Grid Services.

In addition, I respond to the discussion regarding the levelization period and utility-scale alternative issues raised in Order No. 17-357.

Q. Please identify the other PacifiCorp witnesses providing testimony in this proceeding.

A. PacifiCorp witness Mr. Kevin C. Putnam provides testimony addressing the avoided line loss and transmission and distribution deferral elements of the RVOS methodology. My testimony explains how these elements are incorporated in the RVOS workbook.

Q. Please provide a summary of your testimony.

A. I explain the calculation of each RVOS element, describing how PacifiCorp complied with the directives and guidance in Order No. 17-357, and I also provide additional discussion on the derivation of these elements. Overall, PacifiCorp guided its approach for the RVOS calculation by adhering to underlying principles of accuracy, transparency, flexibility and continuous improvement. To demonstrate the application of the RVOS calculation, PacifiCorp created an indicative RVOS resource based on a simple average of expected generation profiles for fixed-tilt solar resources at three locations in its Oregon service territory: the Willamette Valley; Southern Oregon; and Central Oregon.

Table 1 shows 25-year nominal-levelized results by RVOS element starting in 2018 for this indicative resource. For comparison, results are shown based on the standard avoided costs, as ordered by the Commission, as well as based on PacifiCorp's Partial Displacement Differential Revenue Requirement (PDDRR) methodology, which the company proposes as a more up-to-date and accurate forecast of the value of solar.

Table 1: Resource Value of Solar
$/megawatt-hour (MWh) Nominal Levelized (2018-2042)

Element	**Standard: 2015 IRP**	**PDDRR: 2017 IRP**
Avoided energy cost	36.69	33.63
Avoided generation capacity cost	12.20	17.96
Avoided transmission and distribution capacity	0.08	0.08
Avoided line losses	2.34	2.14
Administration	(2.88)	(2.88)
Integration	(0.82)	(0.82)
Market price response	0.15	0.00
Avoided hedge value	1.84	1.68
Avoided environmental compliance	0.11	0.22
Avoided RPS compliance	0.00	0.00
Grid services	0.00	0.00
Total Resource Value of Solar	**49.72**	**52.00**

OVERVIEW

Q. Why is completing the calculation for RVOS critical at this time?

A. It is important that the Commission continues to thoroughly review and analyze how to properly apply the valuation method for distributed solar generation as we move into this docket where the RVOS methodology is being implemented to produce utility-specific values. While my testimony represents the initial filing in this proceeding, it is based on the culmination of several years of effort by the Commission, Staff, and stakeholders to determine the elements that should feed into the calculation of the RVOS. Although important decisions have already been made by the Commission regarding the definition and inclusion of specific elements, PacifiCorp expects continued refinements will be made throughout this proceeding and future proceedings.

Q. What is your understanding of the intended use of the RVOS at this time?

A. The RVOS methodology should be a flexible tool capable of customization for specific applications and incorporating currently available information for each utility. The Commission recognized the need for flexibility and evolution of the RVOS calculation, noting that while "the first version of RVOS is meant to be generally applicable to a solar system installed by a retail, mass market customer today" the Commission has "not prejudged any applications."[1] PacifiCorp also understands that the RVOS will likely inform valuation of community solar projects,[2] among other potential applications, and the company will actively engage in future

[1] *In the Matter of Public Utility Commission of Oregon Investigation to Determine the Resource Value of Solar*, Docket No. UM 1716, Order No. 17-357 (Order No. 17-357) at 16 (Sep. 15, 2017).
[2] Order No. 17-357 at 17.

workshops to address this question. The uncertainty regarding the future application of the RVOS, combined with the need for the RVOS to remain as accurate as possible over time, further underscores the importance of continuing to refine this calculation as the Commission clarifies future uses.

Q. The Commission has not yet determined how often the RVOS should be updated, but noted that it "will decide later, based on application, whether RVOS should be updated annually or every two years."[3] What is PacifiCorp's position on this issue?

A. To create the most accurate RVOS that is fair to all customers, the utility-specific RVOS calculation and inputs should be updated as often as necessary to reflect current market conditions and distribution system characteristics. Frequent updates will minimize the potential time where distributed solar is improperly valued due to outdated RVOS calculations. Ensuring an accurate and up-to-date calculation is particularly important if PacifiCorp will be entering into long-term contracts or commitments based on these prices.

Q. Please summarize the components of the RVOS model workbook.

A. PacifiCorp started with the RVOS model workbook prepared by E3, populated inputs specific to its system and portfolio, and modified the inputs and calculations where necessary, for instance to account for inputs with more granularity. PacifiCorp has included its RVOS model workbook in supporting workpapers accompanying this filing. The first tab of the RVOS model spreadsheet also now includes a brief description of the inputs related to each of the RVOS elements and identifies the

[3] Order No. 17-357 at 17.

specific location within the workbook where the input is entered. The RVOS model workbook contains links to additional supporting workpapers that have also been provided with this filing.

AVOIDED ENERGY

Q. Please describe how PacifiCorp complied with the Commission's direction regarding the calculation of avoided energy costs.

A. The Commission provided three directives related to avoided energy costs that I address in my testimony. First, PacifiCorp used "the same pricing source used to develop average monthly or annual on and off-peak standard qualifying facility (QF) energy values."[4] Second, the avoided energy costs reflect a distribution of potential hydro conditions—below I explain the analysis used to represent the resulting average price.[5] Third, PacifiCorp applied a 12-month-by-24-hour (12x24) price shape—below I provide a detailed explanation as to how those blocks were created.[6]

Q. Do any other RVOS elements directly impact avoided energy costs?

A. Yes. The avoided hedge value and market price response elements both directly impact the avoided energy costs, which I will address later in my testimony.

Standard Qualifying Facility Avoided Energy Costs

Q. What are PacifiCorp's current standard non-renewable avoided energy costs?

A. During the sufficiency period, PacifiCorp's current standard non-renewable avoided energy costs are based on a blend of the forward prices for the Mid-Columbia, California-Oregon Border (COB), and Palo Verde markets. The ratio of the blended

[4] *See* Order No. 17-357 at 4.
[5] Order No. 17-357 at 5.
[6] Order No. 17-357 at 4.

prices varies by month and by on-peak hours and off-peak hours based on the relative weighting of the incremental transactions by market in a PacifiCorp Generation and Regulation Initiative Decision Tools (GRID) study that result from adding a new zero-cost resource in Oregon.

During the deficiency period, PacifiCorp's current standard non-renewable avoided energy costs are based on the variable costs of the same combined cycle combustion turbine (CCCT) used to set avoided generation capacity values. The variable fuel costs for this proxy resource are based on forward natural gas prices. PacifiCorp's currently approved standard non-renewable QF avoided cost became effective on June 1, 2017 (June 2017 standard avoided cost). The June 2017 standard avoided costs reflect PacifiCorp's March 2017 official forward price curve (OFPC), blending ratios prepared in April 2017 and the heat rate of the proxy CCCT from the 2015 Integrated Resource Plan (IRP).

Q. How does PacifiCorp propose to incorporate the standard non-renewable avoided energy costs in the RVOS calculation?

A. Consistent with the Commission's direction, the RVOS calculation is based on the same pricing source used to develop the average monthly or annual on- and off-peak standard energy values. For PacifiCorp, this is the average avoided energy values for each month underlying the June 2017 standard avoided costs.

Q. Are there any upcoming changes to standard non-renewable QF avoided costs?

A. Yes. An update to standard non-renewable avoided costs is required within 30 days of acknowledgment of the 2017 IRP, which is expected to occur in the next few months. This update would impact the deficiency year, fixed costs of the proxy

CCCT, 12x24 Loss of Load Probability (LOLP) pattern, and OFPC assumptions. However, updates to these discrete inputs are straightforward and not expected to require changes to the underlying RVOS methodology. PacifiCorp expects that it will update the inputs in the RVOS workbook to reflect standard avoided costs based on the 2017 IRP during the pendency of the RVOS proceeding.

Hydro Conditions

Q. The Commission asked utilities to explain and provide "statistical analysis demonstrating how their energy values are scaled to represent the average price under a range of hydro conditions."[7] Please summarize PacifiCorp's approach.

A. To comply with the Commission's direction to represent a range of hydro conditions, PacifiCorp started with its most recent OFPC, and then prepared two additional forward price curves based on "wet" and "dry" (i.e., "favorable" and "unfavorable," respectively) hydro conditions. Years that had hydro generation within seven percent of the historical average were designated as normal. The average hydro generation during normal historical years was also very close to the historical average. Years with hydro generation more than seven percent above the historical average were designated as wet, while those with hydro generation more than seven percent below the historical average were designated as dry. The proposed market prices for use in the RVOS are a blend of the wet, dry, and normal price forecasts, with weightings for each condition based on the distribution of historical hydro conditions, which I will explain.

[7] Order No. 17-357 at 5.

Q. Please explain the proposed hydro condition methodology.

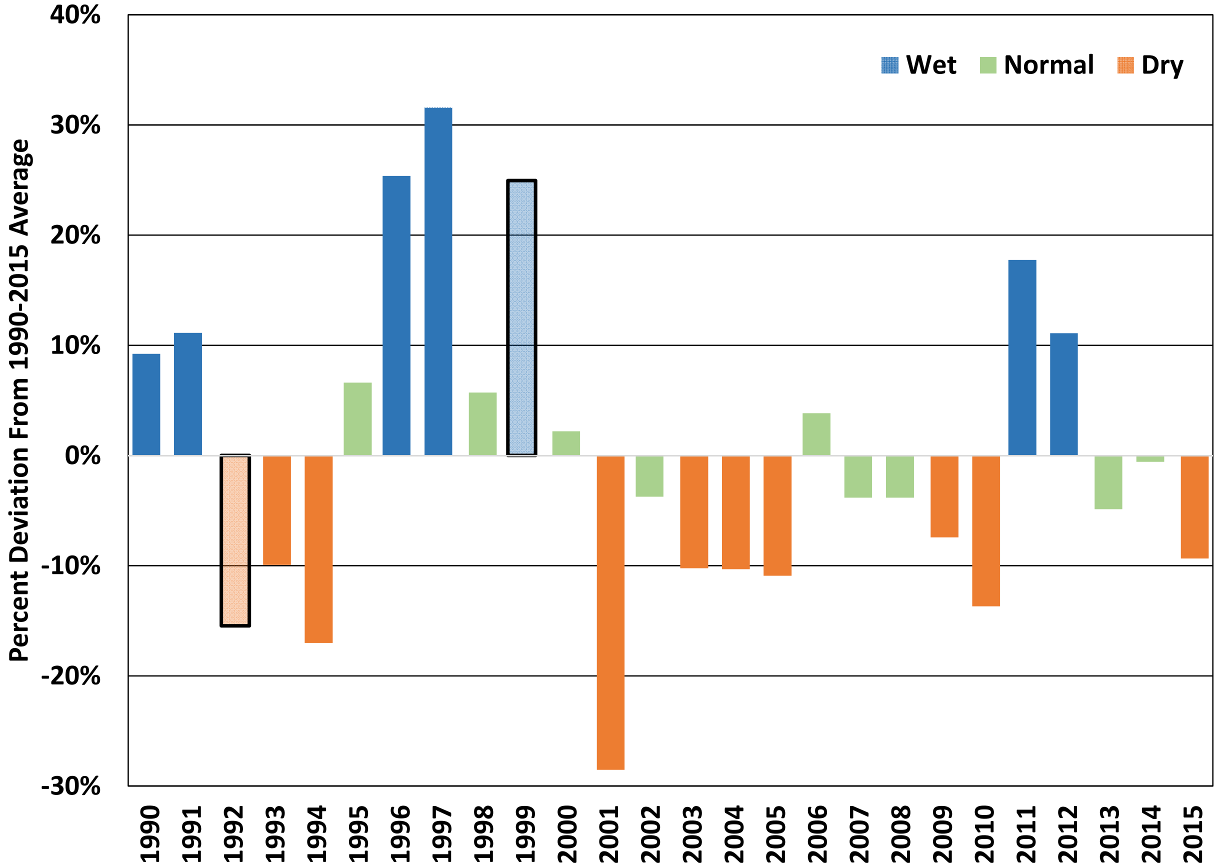
A. Sufficiency period avoided energy values are based on electricity market prices in PacifiCorp's most recent quarterly OFPC at the time an avoided cost update filing is prepared. For the first 72 months, PacifiCorp's OFPC reflects its trader's view of the forward market verified against third-party sources for a given quote date. This market view transitions to a modeled forecast of forward prices based on market fundamentals (i.e., projected regional fuel costs, projected regional loads, projected regional resources, projected regional hydro generation, etc.). Months 73-84 are a blend of the trader's view and the market fundamental view developed using the Aurora model. Beyond 84 months, PacifiCorp's OFPC is entirely based on a market fundamentals analysis using the Aurora model. Aurora studies used to develop the OFPC use median hydro conditions, and include results during the first 84 months, even though those results are overridden by the market view.

To calculate the impact of a range of hydro conditions, PacifiCorp prepared two additional forward price curves using hydro generation inputs consistent with wet and dry hydro conditions, rather than normal hydro conditions. 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 and as shown in Figure 1. Hydro generation in 1999 was 25 percent higher than the average for 1990 through 2015, while hydro generation in 1992 was 15 percent lower. The change in prices in the wet and dry hydro studies relative to the Aurora results under normal hydro conditions was calculated for each market, by month, and on- and off-peak period. The average hydro generation during wet years in the historical period was 19 percent more than the historical average, somewhat less than the 25 percent deviation in the 1999 wet price curve. While 27 percent of the historical period was designated as wet years, they are less wet than 1999, so the weighting of the wet price curve based on 1999 is reduced proportionately. Similarly, the average hydro generation during dry years in the historical period was 13 percent less than the historical average, which is slightly less extreme than the 15 percent deviation represented in the 1992 dry price curve. While 38 percent of the historical period was designated as dry years, they are less dry than 1992, so the weighting of the dry price curve based on 1992 is reduced proportionately. The weighting of the normal price curve is adjusted to offset the changes in the weighting of the wet and dry price curves.

After accounting for the range of wet, normal, and dry conditions over all years between 1990 and 2015, the market prices based on wet conditions represented by 1999 were given a 20 percent weighting[8] and the market prices based on dry conditions represented by 1992 were given a 33 percent weighting,[9] with market prices based on normal conditions representing the remaining 47 percent.

[8] (Wet Hydro Year Count / Total Year Count) * (Average Wet Hydro Percent Deviation / 1999 Hydro Percent Deviation) = (7 / 26) * (19% / 25%) = 27% * 75% = 20%
[9] (Dry Hydro Year Count / Total Year Count) * (Average Dry Hydro Percent Deviation / 1992 Hydro Percent Deviation) = (10 / 26) * (-13% / -15%) = 38% * 86% = 33%

Figure 1: Pacific Northwest Hydro Conditions, 1999-2015



Q. What is the result of PacifiCorp's hydro condition adjustment?

A. From 2018 through 2027, the hydro condition adjustment results 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 adjustment during the deficiency period, as avoided energy costs are not based on electricity prices during that timeframe. After accounting for the blending ratios used in standard rates, the impact on avoided energy costs is a reduction of less than one percent.

Q. How do you propose updating the hydro condition adjustment going forward?

A. Because of the minimal impacts from these adjustments, PacifiCorp proposes to update the hydro condition calculation no more than once per year. Interim updates to other RVOS components, including the OFPC, would continue to incorporate the results of the existing hydro condition calculation. The core results of the hydro condition calculation are the wet, dry, and normal weightings from the historical period, and the wet and dry market price adjustments. Because the weightings are based on more than 20 calendar years of data, the addition of one or two years of historical data is unlikely to have a meaningful impact. Similarly, while market prices may change as a result of gas prices or other conditions, the percentage change under expected wet and dry conditions is unlikely to be significantly different absent dramatic changes in expected loads and resources.

Hourly Price Shape

Q. Please provide a detailed explanation of the 12x24 price shape proposed by PacifiCorp.

A. The RVOS model uses an annual average energy price with an 8760 or 12x24 energy price shape. The price shaping can be considered in two stages. In the first stage, the annual price is shaped to monthly values. Since PacifiCorp's standard avoided costs are calculated using its OFPC, which has monthly detail, the annual price is simply the aggregate of monthly values. As a result, monthly shapes are readily available.

In the second stage, monthly prices are shaped to hourly values. PacifiCorp's OFPC includes on- and off-peak granularity, but does not include hourly granularity. Distinguishing between on- and off-peak hours is not necessary because solar generation is not correlated with weekdays, weekends, and holidays, so the on- and off-peak values are combined to a single monthly average price. To create an hourly shape, PacifiCorp proposes using the results of Energy Imbalance Market (EIM) operations. Specifically, PacifiCorp proposes using 15-minute EIM market prices for the most recent 12 month period, in this instance, the 12 months ending September 2017.

Under this approach, hourly shaping would be based on EIM load aggregation point (LAP) prices, with Mid-Columbia hourly shaping based on the PacifiCorp west (PACW) LAP, Palo Verde hourly shaping based on the PacifiCorp east (PACE) LAP, and COB hourly shaping based on the Malin LAP. The market price shape is a "scalar" based on the average market prices in a month during a given hour, relative to the average market price in that month during all hours. For instance, if the average market price during hour-ending 10 in May is $18/MWh, and the average market price during all hours in May is $20/MWh, then the scalar for hour-ending 10 in May would be 90 percent.[10] Before the monthly shape from the OFPC is incorporated, the average of the 24 hourly scalars for a given month is always 100 percent. Similarly, when the monthly and hourly shapes are combined, the hourly market price shapes average to one over the course of each year.

Q. Why is the use of EIM data to produce hourly price shapes reasonable?

A. As noted above, PacifiCorp's OFPC only contains monthly on- and off-peak granularity, and not hourly granularity. During the first 72 months, the OFPC reflects its trader's view of the forward market for monthly products, and cannot be decomposed into hourly values. While the Aurora model results reflect a fundamental market view, PacifiCorp has never configured the model to report hourly

[10] $18/MWh / $20/MWh equals 90 percent.

results and it is not clear whether doing so would provide reasonable results. PacifiCorp's current hourly price shaping is based on historical hourly transactions, as reported to Powerdex. Due to the proprietary limitations on PacifiCorp's subscription to information regarding hourly market prices, PacifiCorp instead proposes to use publicly available information to promote transparency for the Commission, Staff, and parties in the RVOS calculation. Because the hourly price shape is applied to PacifiCorp's monthly OFPC values, the effect of any systematic market price spread between sub-hourly EIM prices and hourly prices available in bilateral markets would be limited.

Q. Why is the use of data from the most recent 12 months reasonable?

A. PacifiCorp selected the most recent year of actual results because it more accurately reflects expected future conditions than data from earlier periods and is the minimum timeframe necessary to identify specific conditions for each month of the year. Both PacifiCorp and the western interconnect as a whole have experienced a significant increase in the number of solar resources, including additional solar resources in the last 12 months, and this trend is expected to continue over the next several years.[11] This trend of increased solar resources has a meaningful impact on market price shapes, an impact that is acknowledged by the Commission's inclusion of market price response element in the RVOS methodology. Because of the diurnal nature of solar, its impact on the market is different from other variables that impact market prices, such as load, hydro conditions, or natural gas prices. For those other variables, the use of a longer historical period to better account for deviations from

[11] U.S. Energy Information Administration. Annual Energy Outlook 2017. Tables 58.19-58.22. Available online at: https://www.eia.gov/outlooks/aeo/tables_ref.php.

normal conditions would be appropriate. These variables are unlikely to significantly impact the results of the proposed EIM hourly price shaping since it is only used to set prices within one month relative to one another, and the intra-month relationships being measured from the EIM data are likely to be less affected by high load or high hydro conditions. Furthermore, it is unlikely that the impact from these variables in the last 12 months would outweigh the impact of changes in the quantity of solar resources over a longer historical period.

Q. Are there any additional considerations in the calculations of hourly scalars using EIM prices?

A. Yes. EIM prices can vary widely, and the price shape for an hour and month can be skewed by the presence of a few very high or very low prices. PacifiCorp proposes that the EIM prices used to calculate the hourly scalars be capped to limit the impact of potentially more extreme results.

Current EIM regulations restrict settlement prices to energy values between +$1,000/MWh and -$150/MWh, with these values typically occurring only when the calculated EIM dispatch solution is infeasible, such as when all other resource options in the model have been deployed. A single hour with prices approaching either of these values will have an appreciable impact on the monthly average for that hour since there are only about 30 days in a month. These prices are generally a result of unexpected conditions, which may include significant deviations from forecasted load, wind, or solar. Such deviations are largely random, so the presence of extreme values is generally a chance occurrence, rather than a characteristic of a given hour. PacifiCorp is therefore proposing that the EIM prices used to calculate the 12x24 scalars be capped at +$200/MWh and -$50/MWh. This balances the evidence that extreme events did occur in particular hours, with the likelihood that such events could occur in any hour.

Q. What are the hourly market price shapes using EIM results?

A. The hourly market scalars based on EIM results for PacifiCorp's PACW balancing authority area (BAA) are shown in Figure 2. In each month, hours with the highest scalars reflect the highest market prices and are shown in red, while hours with the lowest scalars reflect the lowest market prices and are shown in green. As previously indicated, comparable scalars are also calculated for PacifiCorp's PACE BAA and for the California Independent System Operator at Malin. These values are applied to a monthly price, so the scalars for each month average to one.

Figure 2: PACW Hourly Market Scalars by Month

Period	Hour																								
	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	0.8	0.7	0.7	0.8	0.8	0.8	0.9	1.4	1.1	1.1	1.3	1.0	0.8	0.7	0.7	0.8	0.9	1.3	1.2	1.2	1.6	1.2	1.2	0.9	1.0
2	0.9	0.8	0.8	0.8	0.9	1.0	1.1	1.5	1.3	1.1	0.9	0.8	0.8	0.7	0.6	0.6	0.8	1.4	1.9	1.3	1.2	1.1	1.1	0.8	1.0
3	0.8	0.5	0.6	0.7	0.6	0.9	1.3	2.2	1.4	1.0	0.8	0.6	0.4	0.5	0.2	0.3	0.3	1.0	1.8	2.0	2.1	1.8	1.5	0.9	1.0
4	0.8	0.6	0.3	0.4	0.4	0.8	1.1	2.0	1.6	1.3	0.7	0.6	0.4	0.7	0.5	0.7	0.5	0.8	1.2	1.8	2.3	1.8	1.8	1.0	1.0
5	0.7	0.6	0.5	0.4	0.5	0.7	0.8	1.2	1.1	1.0	1.0	0.8	0.9	1.0	1.0	1.3	1.3	1.2	1.2	1.2	1.5	1.6	1.5	1.0	1.0
6	1.0	0.7	0.5	0.3	0.5	0.7	0.4	0.9	1.0	0.8	1.0	1.0	1.1	1.5	1.2	1.3	1.4	1.3	1.3	1.2	1.2	1.4	1.4	1.1	1.0
7	0.9	0.8	0.8	0.8	0.8	0.8	0.7	0.8	0.9	0.9	1.0	1.0	1.0	1.1	1.1	1.2	1.3	1.2	1.1	1.3	1.2	1.1	1.1	1.0	1.0
8	0.8	0.7	0.7	0.7	0.7	0.8	0.7	0.8	0.8	0.8	0.8	0.9	0.9	1.0	1.2	1.3	1.5	1.4	1.6	1.5	1.3	1.2	1.0	0.9	1.0
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	1.1	1.1	1.2	1.5	1.6	1.2	1.1	1.1	0.9	1.0
10	0.9	0.9	0.8	0.8	0.8	0.9	0.9	1.1	1.1	1.3	1.3	1.2	1.1	0.9	0.8	0.7	0.8	0.9	1.4	1.4	1.1	1.0	1.2	0.9	1.0
11	0.9	0.8	0.7	0.8	0.8	0.8	0.8	1.4	1.2	1.1	1.0	1.0	0.9	0.8	1.0	0.9	1.0	1.3	1.2	1.2	1.2	1.0	1.2	1.0	1.0
12	0.8	0.7	0.7	0.8	0.7	0.8	0.9	1.2	1.2	1.2	1.3	0.9	0.8	0.8	0.8	0.8	1.1	1.3	1.4	1.1	1.1	1.1	1.5	0.9	1.0
Avg	0.9	0.7	0.7	0.7	0.7	0.8	0.9	1.3	1.1	1.0	1.0	0.9	0.8	0.9	0.8	0.9	1.0	1.2	1.4	1.4	1.4	1.3	1.3	1.0	1.0

Q. What is the final result of PacifiCorp's proposed hourly market price shaping methodology?

A. The EIM hourly scalars based on PACW, PACE, and Malin are combined using the market blending ratios applicable to standard avoided costs and the result is multiplied by the applicable monthly scalars from PacifiCorp's OFPC to produce distinct market price scalars for each year. These values are applied to an annual price, so the scalars for each year average to one. The resulting hourly market scalars for 2019 are shown in Figure 3.

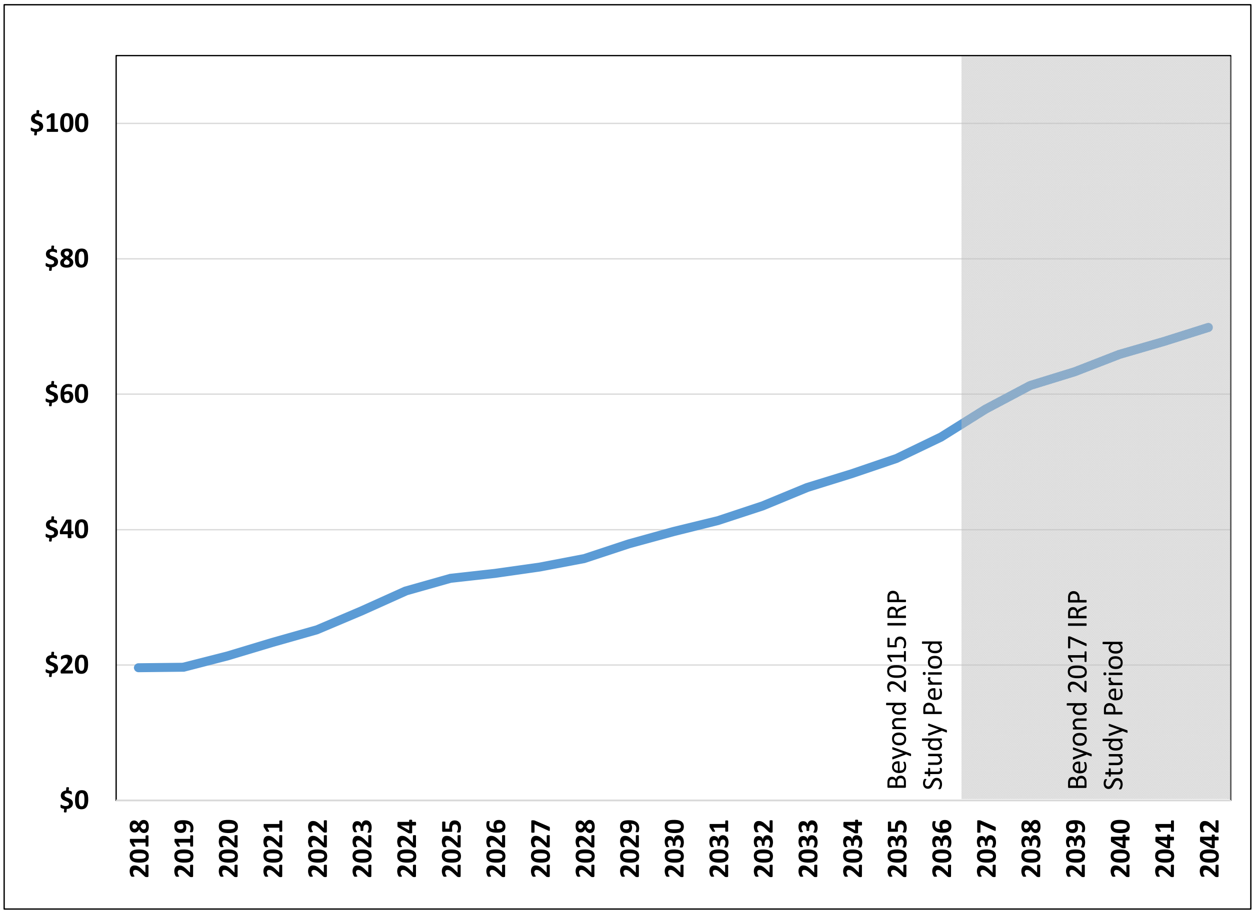
Figure 3: RVOS Hourly Market Scalars for 2019

Period	Hour: 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

Q. What are the avoided energy costs applicable to the indicative RVOS resource?

A. Figure 4 below shows the average annual avoided energy costs for the indicative RVOS resource. This reflects the combination of the annual energy cost and the hourly price shapes consistent with the indicative resource's generation profile. Years that extend beyond the study period considered in the company's IRP analysis are shown for reference.

Figure 4: RVOS Avoided Energy Cost for the Indicative Fixed Solar Resource



AVOIDED COST UPDATES

Q. The Commission acknowledges concerns about tying RVOS energy values to litigated QF avoided cost filings, but notes that it is too early to decide whether QF avoided costs and RVOS should be "synched" with their updates.[12] What is PacifiCorp's position on this issue?

A. Accuracy is an important element of both the RVOS and QF avoided cost calculations. Failing to incorporate updated information in a timely manner would reduce the accuracy of the results and could result in inaccurate pricing with

[12] Order No. 17-357 at 4.

significant long-term impacts to customers. While there is an administrative burden in updating and approving the RVOS calculation, this must be weighed against the potentially long-term nature of contracts that may be entered into using the RVOS calculation, which would have the potential to harm customers. PacifiCorp appreciates the rigor employed by the Commission in Phase I; this foundational work should expedite the process for RVOS updates.

PacifiCorp expects that the Commission and Staff will strive for continuous improvement and accuracy in the RVOS calculation, but also expects that incorporating discrete updates to the completed calculation should be a straightforward process. Examples of straightforward updates include incorporating a readily verifiable updated forward price curve, which only impacts avoided energy values, and should not require revisiting other elements. With that in mind, to the extent energy or generation capacity inputs are tied to the standard QF avoided costs, I recommend that the RVOS calculation be updated whenever standard QF avoided costs are updated.

AVOIDED GENERATION CAPACITY

Q. Please explain how PacifiCorp addressed this element.

A. The Commission directed utilities to "determine the capacity value consistent with the Commission's standard non-renewable QF avoided cost guidelines."[13] Consistent with the Commission's directive for utilities to "provide capacity value and timing (deficiency date) in line with their current approved standard non-renewable QF avoided cost capacity value,"[14] PacifiCorp included its standard non-renewable QF

[13] Order No. 17-357 at 21.
[14] Order No. 17-357 at 6.

avoided cost capacity value.

PacifiCorp's current avoided capacity costs are based on the fixed cost of a CCCT from the 2015 IRP, beginning at $149/kilowatt (kW)-year starting in 2028, and increasing at inflation thereafter. The capacity value and deficiency date in the June 2017 standard avoided costs were approved following acknowledgment of the 2015 IRP. In accordance with Order No. 14-058, the capacity value of a standard QF resource is calculated by multiplying the annual fixed costs of the proxy CCCT by the capacity contribution of the QF resource from the acknowledged IRP.[15]

Q. How is the capacity contribution of solar resources calculated in the IRP?

A. PacifiCorp's IRP includes technology- and location-specific capacity contribution values for solar resources. In the 2015 IRP, the capacity contribution for west-side fixed tilt solar resources was 32.2 percent of nameplate capacity, based on a capacity factor approximation method and using a representative utility-scale solar profile for Lakeview County, Oregon.[16] Under the method used in the 2015 IRP, a resource's capacity contribution is based on its expected capacity factor with a weighting based on the LOLP for each hour. As a result, resources in different locations or with different panel orientations will have a different capacity contribution.

Q. How do you propose accounting for capacity contribution in the RVOS workbook?

A. Because the solar resources to be assessed using the RVOS workbook are likely to

[15] *See In the Matter of Public Utility Commission of Oregon Investigation Into Qualifying Facility Contracting and Pricing*, Docket No. UM 1610, Order No. 14-058 (Feb. 24, 2014).
[16] 2015 Integrated Resource Plan. Volume II. Appendix N: Wind and Solar Capacity Contribution Study. http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2015IRP/PacifiCorp_2015IRP-Vol2-Appendices.pdf.

include a range of generation profiles, a single capacity contribution value is unlikely to be a reasonable representation for all solar resources. Instead, capacity contribution value for a proposed resource or set of resources can be determined based on the 12x24 LOLP results from the IRP capacity contribution study. Specifically, the capacity value of a proposed resource would be weighted based on the LOLP in each hour. Under this approach, a resource delivering in 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. A solar resource would receive a capacity contribution based on its expected output during those hours with LOLP greater than zero.

Q. What are the avoided generation capacity costs for the indicative RVOS resource?

A. The generation profile of the indicative RVOS resource discussed previously has an effective capacity contribution of 26.1 percent, which equates to a capacity payment of $23/MWh starting in 2028, or a 25-year levelized value of $12/MWh.

Resource-Balance Year

Q. The Commission directed utilities to "remove incremental distributed solar PV from the load forecast in the initial filing."[17] Specifically, the Commission directed utilities to use the "last acknowledged IRP resource-balance year, and then remove new incremental expected distributed solar PV from that forecast, and then if applicable, provide an adjusted deficiency date."[18] Please describe the company's approach.

A. PacifiCorp's most recently acknowledged IRP is the 2015 IRP; therefore, consistent with the Commission's direction, PacifiCorp started with the 2028 resource-balance year from the 2015 IRP, and then removed the new incremental expected distributed solar photovoltaic (PV) from the forecast. The incremental Oregon distributed generation delivered during the time of the system peak in the 2015 IRP load forecast is equivalent to approximately 13 megawatt (MW) of nameplate solar resource, with a capacity contribution of approximately four MW. In addition to a thermal resource, the 2015 IRP preferred portfolio calls for over 400 MW more front-office transactions (FOTs) in 2028 than 2027, so the remaining FOTs available in 2027 are well in excess of the incremental four MW of capacity contribution from Oregon distributed generation. As a result, distributed generation would not be sufficient to change the deficiency date established in the 2015 IRP.

AVOIDED TRANSMISSION AND DISTRIBUTION CAPACITY

Q. How is avoided transmission capacity incorporated in the RVOS calculation?

A. PacifiCorp witness Mr. Putnam provides testimony addressing the transmission

[17] Order No. 17-357 at 8.
[18] *Id*.

deferral element of the RVOS methodology, identifying a value of $5.94/kW-year for deferred transmission capacity upgrades. As discussed by Mr. Putnam, based on solar generation profiles and reliability concerns, solar resources are assumed not to be capable of deferring transmission capacity upgrades.

Q. How is avoided distribution capacity incorporated in the RVOS calculation?

A. Mr. Putnam provides testimony addressing the distribution deferral elements of the RVOS methodology, identifying a value of $13.44/kW-year for deferred distribution capacity upgrades in Oregon. The amount of distribution capacity assumed to be deferred is based on the year and amount of distribution upgrade capacity needs in Oregon for which solar is a viable alternative, the hours with the highest distribution system loading for the viable projects, and the capacity factor of the proposed solar resource in those hours. As noted by Mr. Putnam, solar was a viable alternative for three MW out of 50 MW of expected upgrades in Oregon, yielding a six percent distribution deferral factor – i.e. on average, six percent of solar resource additions are expected to be in locations with distribution deferral needs. For the one location where solar was a viable alternative, the highest loading was projected to occur in hour 17 in July and August. The indicative RVOS resource has a capacity factor of approximately 17 percent in those hours. After including a 10 percent margin to account for solar uncertainty and the 2023 distribution deficiency year, the system average distribution deferral is approximately one percent of solar nameplate capacity, or 0.1 MW of distribution deferral for every 10 MW of solar resource additions.

Q. What are the results of the transmission and distribution deferral elements in the RVOS calculation?

A. Using assumptions applicable to PacifiCorp's Oregon service territory as a whole, transmission and distribution deferral associated with the indicative RVOS resource results in a nominal levelized benefit of $0.08/MWh. However, if the indicative solar resource was located solely in the area where solar was a viable distribution upgrade alternative, the value would increase to $2.28/MWh, with 10 MW of solar nameplate deferring 1.5 MW of distribution upgrade capacity. The value for peak-oriented or west-facing solar resources would be even higher, as these resources would have more output during peak distribution loading and lower overall capacity factors.

Q. What do you recommend for the transmission and distribution deferral elements in the RVOS calculation?

A. Wherever possible, costs and benefits should be aligned. Including incremental benefits for all RVOS resources will understate the value in areas with transmission and distribution needs, potentially resulting in inadequate investment that is insufficient to eliminate the upgrades in question. Likewise, the value in areas without transmission and distribution needs will be overstated, and could potentially lead to additional costs for upgrades necessary to increase export capability. Similarly, even in areas with transmission and distribution needs, those needs are finite, and cost savings will diminish or be eliminated once resource additions reach a certain point. Accurately accounting for the location- and capacity-specific specific benefits of proposed resources in the RVOS calculation will best ensure that customer indifference is maintained.

AVOIDED LINE LOSSES

Q. How are avoided line losses incorporated in the RVOS calculation?

A. PacifiCorp witness Mr. Putnam's testimony provides additional details on the avoided line loss element of the RVOS methodology. PacifiCorp has identified avoided line losses specific to the following interconnection levels consistent with the losses included in Oregon retail rates. The average energy losses included in Oregon retail rates are as follows:

- Transmission: 4.53 percent
- Primary: 6.90 percent
- Secondary: 10.01 percent

Mr. Putnam describes how PacifiCorp calculated marginal line losses for interconnections at the primary and secondary levels as a function of Oregon load. The relationship between load and losses was used with a typical Oregon load shape to develop a 12x24 profile of marginal losses for both primary and secondary interconnections. The effective loss rate for a given RVOS resource is thus dependent on its generation profile. In addition, resources connected to an area that experiences surplus generation conditions would receive prorated avoided line losses limited to those periods when the area is not exporting generation.

Q. Do avoided lines losses impact other RVOS elements?

A. Yes. Avoided line losses represent resources that no longer need to be deployed, as a result, the avoided generation capacity and avoided transmission and distribution capacity elements include additional value associated with avoided line losses. The reported avoided line loss value in the RVOS calculation reflects avoided energy costs only. The effect of losses on the avoided generation capacity and transmission and distribution deferral elements is included in those elements and not broken out.

Q. How are avoided line losses incorporated in the RVOS calculation of avoided generation capacity and avoided energy?

A. The marginal hourly loss rates for the project-specific interconnection level are used to "gross-up" the expected generation output from the metered level to the system generation input level (i.e., including the losses that PacifiCorp incurs in serving customer load). After this gross-up accounting for avoided line losses, the RVOS resource's effective output is higher—and this higher output is used to determine the avoided generation capacity value. Since the avoided energy value is reported without losses, the energy value for the incremental output associated with losses is reported in the value for the avoided line losses element.

Q. How are avoided line losses incorporated in the RVOS calculation of avoided transmission and distribution capacity?

A. While avoided generation capacity includes all avoided lines losses, avoided transmission and distribution capacity only includes downstream losses. Avoided transmission capacity values are grossed up only for primary and secondary losses, but not for transmission losses. Similarly, avoided distribution capacity is only grossed up for secondary losses.

Q. What are the results for the avoided line loss element in the RVOS calculation?

A. When the indicative RVOS resource is assumed to offset behind-the-meter load connected at the secondary distribution level, it has an average avoided line loss rate of 10.06 percent and incremental generation capacity deferral of 10.10 percent.

When offsetting behind-the-meter load connected to the primary distribution level, or when exporting at the secondary distribution level, it has an average avoided line loss rate of 6.96 percent and incremental generation capacity deferral of 6.99 percent. When offsetting behind-the-meter load connected to the transmission system, or when exporting at the primary distribution level, it has an avoided line loss rate of 4.53 percent for both energy and generation capacity.

ADMINISTRATION

Q. Please describe the Commission's direction regarding administration costs.

A. The Commission asked utilities to propose an estimate of "direct, increased utility costs of administering solar PV programs" and provide a justification for the method and value.[19] The Commission removed "interconnection" from this element and explained that this "element is only intended to capture costs that are both incremental to what the utility incurs for any other customer account and incremental to any portion of the cost paid by the interconnecting solar generator."[20]

Q. **Please list the different elements of administration costs included in the RVOS.**

A. PacifiCorp has included three elements in the computation of administrative costs for inclusion in RVOS: (1) the incremental unrecovered administrative and engineering costs associated with processing customer requests to participate as an RVOS resource; (2) the ongoing administration costs for customer service and billing of net metering customers that exceed the costs to provide those services to traditional customers; and (3) incremental distribution investments required to facilitate the interconnection of distributed generation but are unrecovered from the

[19] Order No. 17-357 at 10.
[20] Order No. 17-357 at 10.

interconnecting customer. Without knowing the exact applications of the RVOS, it is difficult to say with certainty that these are the only administrative costs that could be incurred.

Q. Please explain how the unrecovered administration and engineering costs are calculated.

A. PacifiCorp employed a similar methodology for administration costs as that used for its net metering program in Utah. PacifiCorp dedicates a department to the administration of the customer generation resources it oversees and implements across the six states that it serves, which includes handling and processing interconnection applications. For this calculation, the overall expense of this department for 2016 was multiplied by the proportion of total capacity installed in 2016 in the Oregon net metering program. This amount was then reduced by the application fees received by certain net metering participants. This amount was then divided by the total interconnected capacity, which results in a one-time cost of $7.95 per installed kW. This and the other administrative costs below refer to delivered alternating current (AC) capacity, with direct current installation capacity converted to AC using a ratio of 0.85.

In addition to the administrative costs from the dedicated customer generation department, PacifiCorp has estimated costs from the billing and customer service departments related to initial setup and interconnection of customers who choose to participate in the net metering program. This captures the costs of net metering specific customer calls, the processing of meter exchanges and transitioning customers to modified net metering billing. Similar to the customer generation department specific costs, the total costs from 2016 were divided by the total interconnected capacity to establish a cost of $1.48 per installed kW.

PacifiCorp has also calculated the engineering review time and cost for Oregon customer generation resource applications. Process improvements implemented since 2016 have reduced the engineering review time necessary for most net metering applications. The cost of the average net metering application review is estimated at $32.10 per application. To determine the engineering review cost, the estimated engineering review time was used to determine an average engineering review cost per application. This cost per application was then multiplied by the interconnection applications received in 2016, to establish the total engineering review cost for 2016. This amount was then divided by the total capacity interconnected in 2016 to arrive at an engineering review cost per kW of $2.78. These three calculations were combined to provide an incremental upfront administration cost of $12.21 per installed kW.

Q. Please explain how ongoing customer service and billing costs are calculated.

A. The costs in this category are related to the additional administration and billing support required to facilitate net metering participation. These are costs related to manual review of net metering bills, tracking of excess generation credits from month to month, and manually computing aggregated billing. Unlike the one time administrative and engineering costs associated with the interconnection of generating facilities and the transition to net metering rates that can be clearly assigned to the projects that interconnect within a specific year, these costs are attributable to all currently existing private generation. In order to reflect this difference, PacifiCorp calculated the average capacity of all projects interconnected in Oregon, rather than then the total new projects interconnected in 2016. The total billing support amount for 2016 was then divided by this average interconnected capacity amount to provide an annual billing support fee, producing an annual billing support fee of $1.61 per kW.

Q. Please explain how incremental distribution investment was calculated.

A. In order to determine incremental distribution investment, PacifiCorp established a specific account that captures system upgrades and other capital expenditures that can be directly attributed to net metering installations. These are costs related to transformer upgrades, recloser modifications, and metering costs necessary to facilitate customer generation projects. For this calculation, the total from this account for 2016 was reduced by two factors. First, meter costs were removed as Advanced Metering Infrastructure will be installed in the near future, reducing metering costs directly attributable to net metering. Second, contribution in aid of construction paid by participants was credited to the amount. The remainder after these adjustments was then divided by the total installed capacity in 2016 to establish a one-time cost of $16.53 per installed kW.

Q. How are administrative costs incorporated in the RVOS model?

A. One-time administrative costs are levelized over the 25-year RVOS model study period and added to the ongoing administrative costs, yielding an annual cost per installed kW. The RVOS model spreads these fixed costs over the generation profile of the RVOS resource to calculate the administrative cost on a per MWh basis. This yields a 25-year levelized administrative cost of $2.88/MWh for the indicative RVOS resource.

INTEGRATION

Q. The Commission directed utilities to use inputs for integration costs based on an acknowledged integration study.[21] Does PacifiCorp have a solar integration study that has been acknowledged by the Commission?

A. Not at this time. However, a Flexible Reserve Study that included solar integration costs was prepared as part of the 2017 IRP and is currently pending acknowledgment by the Commission.[22] Because the Commission will consider acknowledgment of the 2017 IRP shortly after this filing in early December, PacifiCorp included its solar integration costs from the 2017 IRP, but can adjust in the future if necessary.

Q. What are the solar integration costs from the Flexible Reserve Study?

A. The Flexible Reserve Study calculated solar integration costs of $0.60/MWh (2016$), escalating at inflation.

Q. While the Commission noted that "very few solar systems are currently installed with storage" it invited The Alliance for Solar Choice to file a proposal on how the Commission could value solar paired with storage in this proceeding.[23] What is PacifiCorp's position on combining solar and storage to reduce integration costs?

A. Storage resources will provide more value if they are dispatched against system

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[21] Order No. 17-357 at 14-15.
[22] 2017 Integrated Resource Plan. Volume II. Appendix F: Flexible Reserve Study. http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2017_IRP/2017_IRP_VolumeII_2017_IRP_Final.pdf.
[23] Order No. 17-357 at 15.

requirements rather than to smooth the output of a single solar resource. PacifiCorp already examined this issue in its Flexible Reserve Study, which indicates that the value of a flexible resource such as a battery is greater when it is available to cover variations from the system as a whole, rather than using it to manage variations from a single solar resource so as to avoid integration charges. PacifiCorp's Flexible Reserve Study examined how reliable operation can be achieved with a smaller portfolio of flexible resources as a result of the diversity between the variations of load, wind, solar, and other resources. The same effect is true within each of these groups—the flexible resources necessary to cover the variations of a single solar resource are proportionately larger than the flexible resources necessary to cover the variations of multiple solar resources. This is because large variations tend not to happen at the same time, so a single increment of flexible resources can be deployed to cover variations from multiple resources or groups. The potential benefits associated with storage system are thus more appropriately addressed in the Grid Services element, rather than as a credit to integration costs.

MARKET PRICE RESPONSE

Q. Please describe the Commission's direction regarding the inclusion of market price response.

A. The Commission directed staff to coordinate the use of E3's model to create a proxy value for market price response for utilities to use.[24] The Commission noted that "utilities should not assume this value is zero, unless there is firm evidence that a value does not exist or that solar installations cannot contribute to it."[25]

[24] Order No. 17-357 at 11.
[25] Order No. 17-357 at 11.

Q. Please describe the value included in PacifiCorp's calculation of the market price response.

A. The Commission ordered "Staff to coordinate or facilitate use of E3's model to create a proxy value for market price response that utilities will use in their initial RVOS filings."[26] Staff's coordination resulted in the suggestion for utilities to perform sequential runs in a production simulation model, with a significant enough increment of solar added to affect the calculated market price, and using these price differences to derive a market price elasticity per MWh produced from solar resources.

PacifiCorp used the price and generation volume relationships identified in the market price hydro sensitivities, discussed above, to estimate the market price impact associated with incremental RVOS resources. In the absence of a specific estimate of the market price response associated with incremental solar resources, the response measured for incremental hydro resources is a reasonable proxy. The impact of movements in market price are dependent on PacifiCorp's net market purchase and sale position, which is calculated on a monthly on- and off-peak basis by market, using Planning and Risk (PaR) model results for the 2015 IRP preferred portfolio. PacifiCorp's net position in each month and on- and off-peak period is multiplied by the market price response for that period. Periods with net sales result in a reduced value for each increment of RVOS resources while periods with net purchases receive an increased value for each increment of RVOS resources. Besides impacting the price of PacifiCorp's net market position, the market price response also impacts the avoided energy cost associated with the resource being evaluated. PacifiCorp

[26] Order No. 17-357 at 22.

calculated the direct market price response based on the expected distributed solar resource additions in Oregon between 2018 and 2036 in the 2017 IRP, a total of 150 MW. Because the impact increases with each solar addition, the proposed RVOS methodology produces an average value by including only half of the assumed solar additions.

Q. What is the impact of the market price response element on avoided energy costs?

A. From 2018 through 2027, the market price response element results in an increase to avoided energy costs by $0.21/MWh. During the deficiency period, the solar resource has avoided energy costs based on a CCCT resource so there is no net change in PacifiCorp's market position and thus no market price response.

Q. Does the market price response element improve the accuracy of avoided energy costs?

A. No. Avoided energy costs are based on PacifiCorp's standard avoided cost calculation, developed at the time of the 2015 IRP, with an updated OFPC as of March 31, 2017. Since March 2017, PacifiCorp has executed contracts for approximately 150 MW of new solar resources, equivalent to what is considered in the RVOS analysis. Based on the theory behind the market price response, these resources would drive down market prices and reduce avoided energy costs. Thus it would be inappropriate to calculate the marginal market price response of potential RVOS resources while ignoring the impact of resource additions in PacifiCorp's portfolio or across the Western Electricity Coordinating Council.

AVOIDED HEDGE VALUE

Q. The Commission directed utilities to use a "proxy value of five percent of avoided energy."[27] Has PacifiCorp included this avoided energy value?

A. Yes.

Q. Does PacifiCorp have concerns about the accuracy of the five percent avoided hedge value?

A. Yes. As discussed by PacifiCorp in Phase I of docket UM 1716, this value is arbitrary and unrelated to either PacifiCorp's hedging policies or the composition of its resource portfolio and obligations.

Q. What are the results for the avoided hedge value element in the RVOS calculation?

A. Five percent of the avoided energy value for the indicative RVOS resource amounts to $1.84/MWh on a 25-year nominal levelized basis.

AVOIDED ENVIRONMENTAL COMPLIANCE

Q. Please describe the Commission's direction regarding avoided environmental compliance.

A. The Commission directed utilities to calculate an avoided environmental compliance value for informational purposes and stated that utility's estimate should be "based on a reduction in carbon emissions from the marginal generating unit with the carbon regulation assumptions from their IRP."[28] The Commission noted that it will decide on the application of this element at a later time.[29]

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[27] Order No. 17-357 at 12.
[28] Order No. 17-357 at 13.
[29] Order No. 17-357 at 13.

Q. Please explain the avoided environmental compliance value included in the RVOS calculation.

A. The Commission directed that the avoided energy costs in the RVOS calculation be based on PacifiCorp's standard avoided costs, which consider PacifiCorp's marginal generating unit to be market transactions during the sufficiency period and a future CCCT during the deficiency period.

PacifiCorp's 2017 IRP included two primary environmental compliance scenarios: Mass Cap A and Mass Cap B, which were intended to incorporate constraints related to the Environmental Protection Agency Clean Power Plan (CPP). Under either Mass Cap A or Mass Cap B, PacifiCorp would have no environmental compliance costs associated with market transactions, so there are no avoided environmental compliance costs during the sufficiency period. Under Mass Cap A, a new CCCT such as the proxy plant used to set standard avoided costs would not be subject to emissions limits, so there would likewise be no avoided environmental compliance costs during the deficiency period. Mass Cap B is a fixed limit on emissions, including those from new resources, which is represented within the IRP modeling as shadow prices per ton of carbon dioxide emissions.

In the preferred portfolio, shadow prices for carbon dioxide emissions average around $6 per ton from 2024 through 2028. Starting in 2029, coal retirements and renewable resource additions reduce emissions below the Mass Cap B threshold, so the shadow price for carbon dioxide emissions drops to zero. After accounting for the heat rate and emissions rate of the proxy plant, the shadow price for carbon dioxide emissions in 2028 equates to a cost of $2.36 per MWh of output. For the reasons described above, 2028 is the only year in which the avoided resource emits carbon dioxide and there is a positive price on emissions. Environmental compliance values based on the Mass Cap B shadow prices and the assumed emissions rate of the avoided CCCT have been included in the ordered RVOS calculation for informational purposes only.

Q. Has PacifiCorp developed an alternative environmental compliance value for the RVOS calculation?

A. Yes. PacifiCorp developed an alternative value reflecting the PDDRR methodology. Unlike the standard avoided cost methodology, the PDDRR methodology identifies a range of avoided resources including coal and gas resources as well as market transactions. As a result, an RVOS resource can impact emissions during the sufficiency period. During the deficiency period, rather than assuming a one-to-one relationship between RVOS resource output and the proxy resource, the PDDRR methodology accounts for the emissions of PacifiCorp's entire portfolio and the generation profile of the proposed resource relative to the capacity equivalent output of a proxy resource from the preferred portfolio. Under this alternative methodology, the Mass Cap B shadow prices from the 2017 IRP preferred portfolio are applied to the forecasted emissions reduction resulting from the RVOS resource, but only when PacifiCorp's emissions are forecasted to exceed the Mass Cap B annual limits. The PDDRR methodology results in carbon dioxide emissions that exceed the Mass Cap B limit in 2024 and 2027, with avoided environmental compliance values of $2.09/MWh and $1.82/MWh, respectively, in those years.

Q. Are avoided environmental compliance costs a reasonable RVOS element at this time?

A. No. PacifiCorp, and by extension its retail customers, do not currently face any environmental compliance obligations that could be avoided with the addition of solar resources. While the 2017 IRP included assumed costs of compliance with the CPP, the CPP was repealed on October 10, 2017. While regulations and legislation may impose such obligations in the future, since the stringency and form remains uncertain it is unclear whether the addition of solar resources would result in avoided compliance costs that would benefit other customers.

Q. What are the results for the avoided environmental compliance element in the RVOS calculation?

A. PacifiCorp's estimate of the value of avoided environmental compliance for the indicative RVOS resource amounts to $0.11/MWh on a 25-year nominal levelized basis. Under the PDDRR methodology, the value of avoided environmental compliance is slightly higher at $0.22/MWh.

AVOIDED RPS COMPLIANCE

Q. Please describe the Commission's direction regarding avoided RPS compliance costs.

A. The Commission directed "utilities to assign a zero value as a placeholder in their initial filings" but noted that it will revisit this issue and endeavor to assign a methodology before the end of Phase II.[30]

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

Q. Has PacifiCorp included this element with a zero value?

A. Yes.

Q. What is PacifiCorp's position on this issue?

A. PacifiCorp's 2017 IRP preferred portfolio includes three different types of cost-effective renewable resources: solar, wind, and geothermal, and these resources are all cost-effective assuming zero RPS-compliance costs. When these cost-effective renewable resources are accounted for, the 2017 IRP indicates that PacifiCorp's first RPS-compliance shortfall will not occur until 2035. Since the 2017 IRP was prepared, PacifiCorp has executed qualifying facility contracts that include renewable energy certificates (RECs) associated with an additional 150 MW of solar resources. PacifiCorp is also preparing a request for proposals to identify additional cost-effective solar resources. Both of these factors should be taken into consideration in determining PacifiCorp's expected RPS compliance obligations.

More importantly, PacifiCorp's 2016R Request For Proposals demonstrated that a significant supply of RECs may be available at relatively low prices. Up to the limits on unbundled RECs and certain hydro RECs, all RECs have the same RPS compliance value regardless of source. A least-cost compliance plan should be based on all opportunities that are reasonably expected to be available, and not limited to a utility-owned proxy resource.

Given the presence of cost-effective renewables in the 2017 IRP and the availability of RECs from other sources, the cost of a new renewable resource is not the same as the cost of RPS compliance. To the extent the benefits a renewable resource provides exceed its cost, the incremental cost to customers of acquiring the

REC that resource can provide is zero, and the cost of RPS-compliance associated with that resource is zero. To the extent that the cost of additional renewable resources exceed the benefits they provide, that incremental cost to customers can only be considered PacifiCorp's RPS compliance cost if alternatives such as unbundled RECs are more expensive or unavailable.

GRID SERVICES

Q. Please describe the Commission's direction regarding grid services.

A. The Commission renamed "security, reliability, and resiliency" to "grid services" and moved ancillary services to this element.[31] The Commission directed utilities to include a zero value for this element.[32] The Commission "retain[ed] this element to capture the potential incremental system benefits from solar in the future"[33] and invited Renewable Northwest 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."[34]

Q. Has PacifiCorp included this element with a zero value?

A. Yes.

Q. What is PacifiCorp's position on benefits provided by solar and storage systems?

A. In general, because of the benefits of optimizing storage dispatch against portfolio requirements rather than an individual solar resource, the value of storage is likely to be highest when it is managed independently of the solar resource it is connected to, though there are likely some efficiency gains from coordination between the solar

[31] Order No. 17-357 at 14-15.
[32] Order No. 17-357 at 16.
[33] Order No. 17-357 at 16.
[34] Order No. 17-357 at 16.

resource and battery at a single site. While there is some overlap between the benefits of storage systems and the RVOS elements, storage systems have a number of additional benefits that are more appropriate to address in PacifiCorp's Storage Potential Evaluation filing in docket UM 1857. In particular, the benefits associated with storage are generally dependent on PacifiCorp's ability to control and dispatch the resource as needed, so it will be necessary to develop payment structures and operational parameters that allow the benefits of storage to be realized. This is different from RVOS, where resource output is not directly controlled by either the customer or the utility. It would be appropriate for the results of the Storage Potential proceeding to inform future RVOS calculations.

Q. Is the proposed RVOS methodology capable of valuing any solar and storage systems?

A. Yes. To the extent a storage system is used for load shifting, storing solar output and releasing it at a later time in accordance with a specified schedule, the effective generation profile of the system would be different from that of the underlying solar resource. Generation profiles directly impact several RVOS elements, including capacity contribution and energy value, so the RVOS calculation would automatically account for the storage system. In addition, solar output that goes directly into co-located storage and is released at a steady level at a later time does not contribute to variations in the balance of load and resources on the system and would not be subject to integration charges. While the RVOS methodology can capture the benefits associated with these types of solar and storage, it will remain necessary to develop rate structures that will ensure any incremental payments are commensurate with ongoing performance. For that reason, I recommend considering all storage systems in a future proceeding.

LEVELIZATION PERIOD

Q. Please describe the Commission's direction regarding the levelization period.

A. The Commission directed utilities to use the E3 workbooks with the elements outlined in Order No. 17-357 "for 25 years beginning in 2018, and provide all supporting assumptions and data."[35] The Commission directed the utilities to "calculate RVOS using a combined cycle gas plant as an avoided resource with the following elements: Energy, Capacity, T&D, Line Losses, Administration, Integration, Hedge Value, and Market Price Response."[36]

Q. Has PacifiCorp provided the information as directed?

A. Yes. PacifiCorp has populated the RVOS workbook with input data for 25 years beginning in 2018.

Q. Does PacifiCorp have concerns with potentially establishing a fixed price for the period of 25 years?

A. Yes. PacifiCorp is concerned about potentially locking in long-term fixed prices for distributed solar resources based on forecasts that will likely be inaccurate over time. PacifiCorp's IRP studies only evaluate its portfolio up to 20 years in the future, and the 25 year term starting in 2018 includes six years beyond the end of the 2017 IRP, and eight years beyond the end of the 2015 IRP, which still forms the basis for avoided energy and generation capacity inputs. Reasonable fixed price terms are critically important to avoid unfairly shifting costs to non-participating customers.

[35] Order No. 17-357 at 17.
[36] Order No. 17-357 at 17.

PacifiCorp endeavors to calculate the most accurate RVOS, but as circumstances change over time, these prices will inevitably be out of date. Fixing prices over a shorter term will ensure that improvements in forecasting and changes in circumstances can be incorporated in the results and implementation so as to reduce unfair cost shifting.

UTILITY SCALE ALTERNATIVE

Q. Please describe the Commission's direction regarding providing a utility scale alternative.

A. The Commission directed utilities to "provide a separate E3 workbook with a RVOS assuming a utility scale solar proxy to replace all elements but T&D capacity, administration, and line losses" for reference.[37] The Commission clarified that utilities should "explain their utility scale proxy and how it relates to their IRPs."[38]

Q. Please explain the utility scale alternative.

A. PacifiCorp has prepared an avoided cost calculation by applying the current non-standard QF avoided cost methodology to the indicative RVOS resources used to illustrate the elements of the RVOS calculation. To reiterate, the indicative resource represents a blend of solar generation profiles representing the Willamette Valley, Southern Oregon, and Central Oregon, with an annual capacity factor of approximately 21 percent. Because the non-standard avoided cost methodology is based on the PacifiCorp's most recently filed IRP, the available deferrable resources and other inputs used in this analysis are drawn from the 2017 IRP.

[37] Order No. 17-357 at 18.
[38] Order No. 17-357 at 18.

Q. Please summarize PacifiCorp's current non-standard avoided cost methodology.

A. Non-standard avoided costs are calculated using the PDDRR methodology approved by the Commission in 2016.[39] Under the PDDRR methodology, new resources are assumed to displace capacity provided by market transactions during the resource sufficiency period followed by a capacity-equivalent slice of the next major thermal resource in the most recently filed IRP or IRP Update preferred portfolio. The GRID model is used to identify the difference between the value of the resource being added, and the value of the displaced market transactions and thermal resource being removed. This accounts for a proposed resource's location, delivery pattern, and capacity contribution and aligns with the company's long term resource plan by incorporating the cost, timing, and characteristics of the preferred portfolio identified by the IRP. This also captures the impact of individual and aggregate impact of resource additions that are being considered. In addition, the current non-standard avoided cost methodology includes a market price floor based on standard avoided costs that is applicable during the resource sufficiency period. Because standard avoided costs have generally been higher than those calculated using the PDDRR methodology, the market price floor results in non-standard avoided costs that are similar to standard avoided costs during the resource sufficiency period. To demonstrate the difference, the PDDRR results shown do not include the market price floor.

PacifiCorp has proposed changes to the non-standard QF methodology, which are pending determination by the Commission in docket UM 1802, and may require a

[39] *In re Investigation into Qualifying Facility Contracting and Pricing*, Docket No. UM 1610, Order No. 16-174 at 2 (May 13, 2016).

subsequent update.

Q. Please describe the key changes related to the 2017 IRP between the standard avoided cost methodology and PacifiCorp's non-standard avoided cost methodology.

A. As indicated above, PacifiCorp's standard avoided cost methodology is based on the most recently acknowledged IRP, currently the 2015 IRP, whereas the non-standard avoided cost methodology is based on the most recently filed IRP or IRP Update, currently the 2017 IRP. As a result, the capacity contribution of the aggregate solar resource using the hourly LOLP from the 2017 IRP is 46.5 percent versus 26.1 percent based on the hourly LOLP shape from the 2015 IRP as previously described. In addition, the first deferrable thermal resource in the 2017 IRP preferred portfolio is a 2029 simple cycle combustion turbine (SCCT) instead of the 2028 CCCT from the 2015 IRP preferred portfolio.

Q. Are any of other inputs and assumptions under the non-standard avoided cost methodology different from those under the standard methodology?

A. Yes. First, the non-standard avoided cost methodology incorporates the 2017 IRP preferred portfolio and September 2017 market prices, as well the latest load forecast and contracts. In contrast, the standard avoided cost methodology is still using the 2015 IRP preferred portfolio and market prices from March 2017, and does not account for changes in load or contracts since the 2015 IRP was prepared. Second, the non-standard avoided cost methodology accounts for resource specific characteristics, including hourly generation profiles and delivery points, whereas standard avoided costs do not make distinctions based on these characteristics.

Avoided Generation Energy and Capacity Using Non-Standard Avoided Cost Methodology

Q. The Commission allowed PacifiCorp to provide energy and capacity values through the non-standard avoided cost modeling approaches.[40] Please describe the analysis.

A. Under the PDDRR methodology, the first utility resource that is eligible for deferral is a 2029 SCCT from the 2017 IRP preferred portfolio. This resource has fixed costs of $139/kW-year starting in 2029, and increasing at inflation thereafter. Avoided energy costs are based on the difference in system costs between two GRID model studies. The first study contains PacifiCorp's current load and resource forecast, including capacity additions identified in the preferred portfolio in PacifiCorp's most recently filed IRP or IRP Update and all of the 2029 SCCT's remaining capacity. The second study adds the proposed resource, in this case a 20 MW fixed solar resource in Oregon, and removes market transactions followed by 8.8 MW of the 2029 SCCT, reflecting a capacity contribution equivalent amount after accounting for solar degradation.

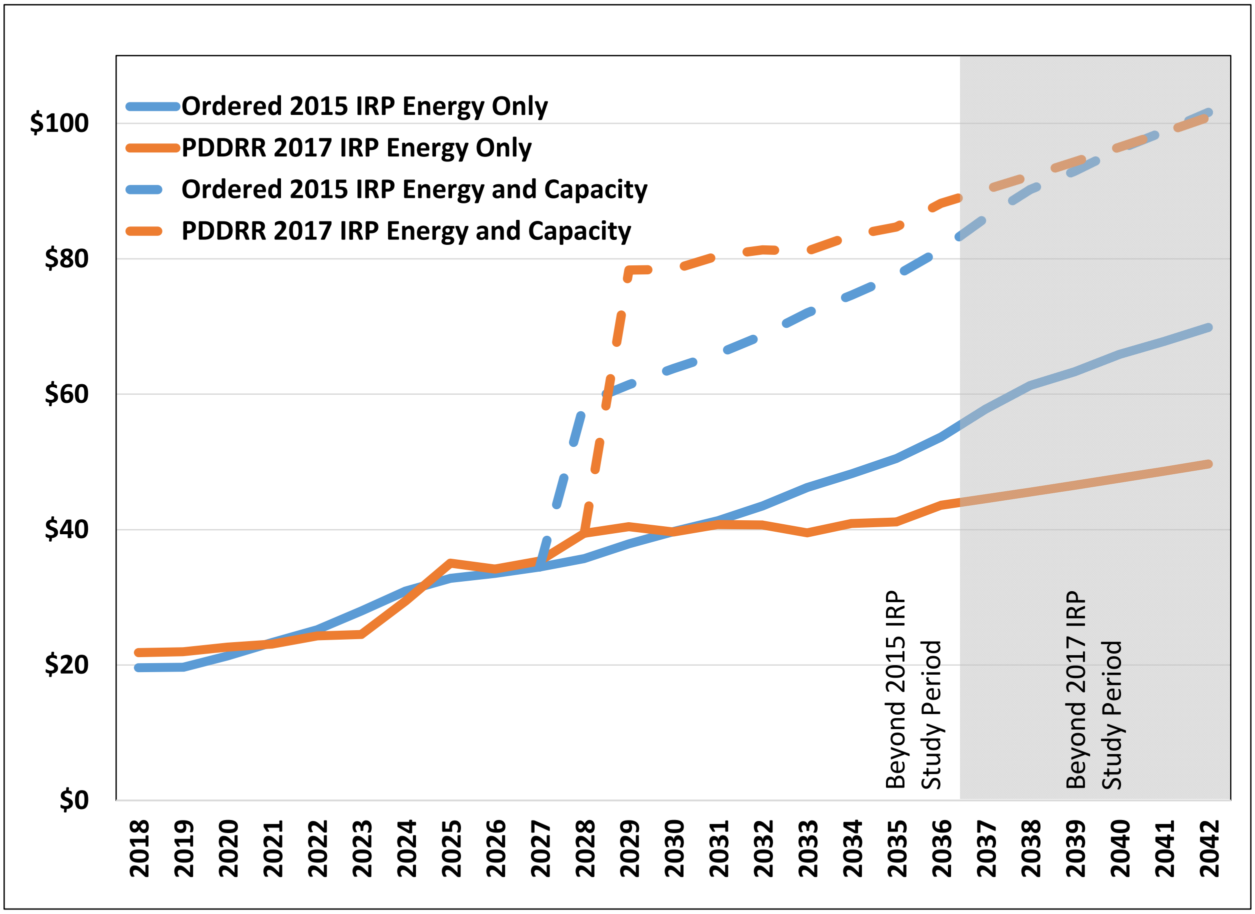
Q. How do the avoided energy and generation capacity results vary under the PDDRR methodology relative to the standard avoided cost methodology?

A. Annual avoided energy and capacity cost for both methodologies are shown in Figure 5. Avoided energy and capacity results under the PDDRR methodology are comparable to those under the standard avoided cost methodology during the sufficiency period. During the deficiency period, avoided energy and capacity values are lower. While the capacity contribution is higher in the 2017 IRP, avoided

[40] Order No. 17-357 at 6.

generation capacity costs are lower and begin one year later. In addition, the PDDRR methodology reflects lost benefits from the displaced SCCT, including the value of operating reserves, contributing to lower avoided costs during the deficiency period. While the RVOS model has an input that similarly accounts for the expected revenues associated with the generation capacity resource, for the ordered calculation this has been left blank consistent with the current standard avoided cost methodology. While the current standard avoided cost methodology accounts for the expected heat rate of the proxy CCCT, it does not account for the dispatchability of that resource, including its ability to provide reserves and ramp up or down, for instance in response to EIM dispatch signals. When the higher solar capacity contribution values from the 2017 IRP are reflected in standard avoided cost following IRP acknowledgment, standard avoided costs would likely approach or exceed non-standard avoided costs.

Figure 5: Standard and PDDRR Avoided Costs for the Indicative Fixed Solar Resource



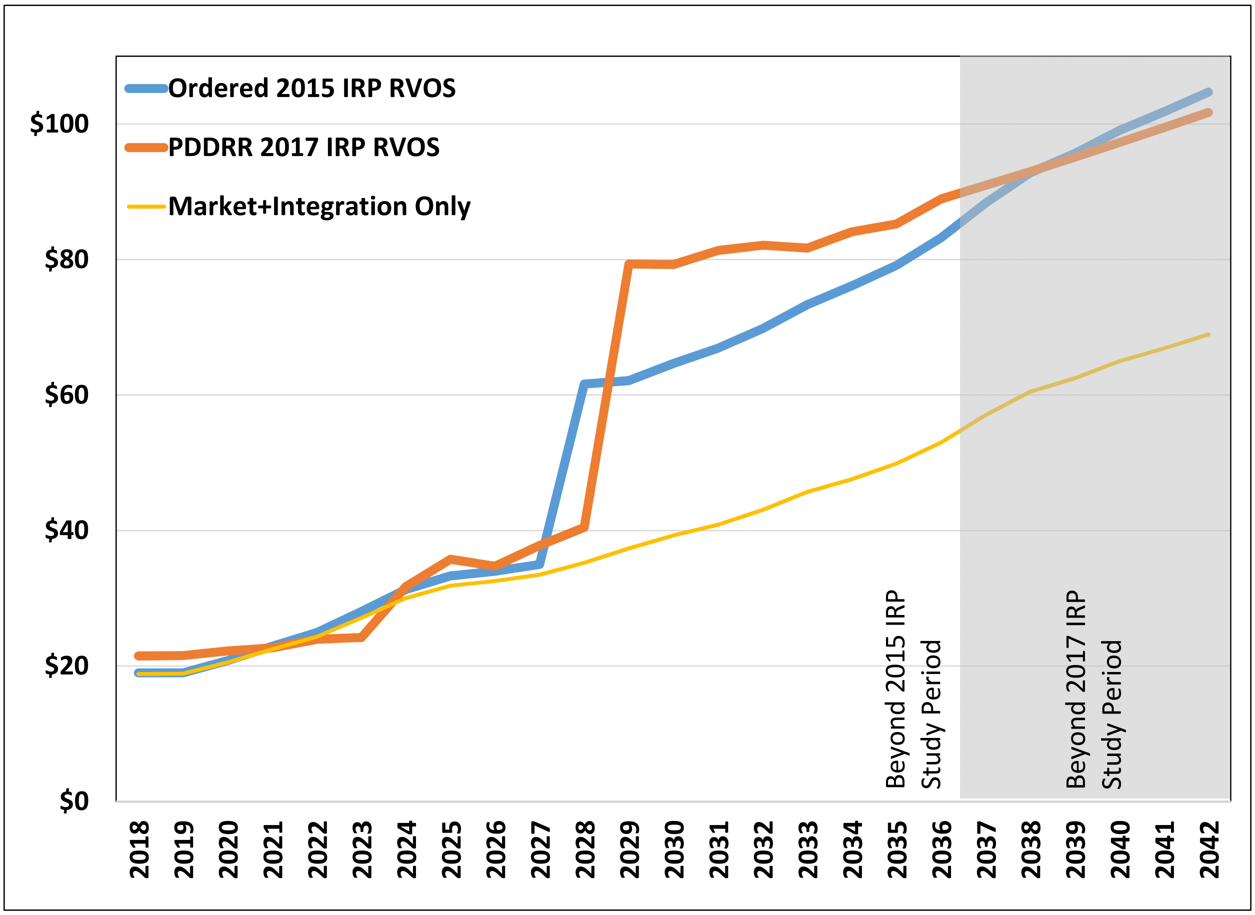
Q. Are any other elements of the RVOS calculation impacted by the inclusion of the PDDRR results?

A. Yes. PacifiCorp has not performed separate hydro condition, hourly price shaping, and market price response calculations, so it is appropriate to continue applying adjustments and assumptions related to these elements in the same manner previously described. Avoided energy costs are also used directly in the calculation of avoided line losses and avoided hedge value, so changes in avoided energy costs are proportionately reflected in those elements.

Q. How do the overall RVOS results from the PDDRR methodology compare to those based on standard avoided costs?

A. After incorporating these additional elements, avoided costs based on the PDDRR methodology are somewhat lower than those based on the standard methodology, as shown in Figure 6. For comparison, results including only avoided energy at market prices and integration costs are also shown.

Figure 6: RVOS Results for the Indicative Fixed Solar Resource



Q. The Commission noted that parties would need access to the models used to calculate the PDDRR.[41] Does the company have concerns with this approach?

A. No. PacifiCorp already provides access to the GRID model to interested parties. After signing a non-disclosure agreement, interested parties may request access to the GRID model, including all inputs and outputs associated with their indicative pricing request. PacifiCorp provides GRID assistance to help users locate the information of interest to them, most of which is readily available. The GRID project input file supporting the PDDRR results has been included in PacifiCorp's confidential workpapers and is available to be uploaded to the GRID model instance of any party that has access.

Q. The Commission noted that it "will balance accuracy, transparency, and accessibility to parties" as it determines the best RVOS methodology.[42] What is PacifiCorp's position on this issue?

A. First, I would note that the Commission has already determined that the PDDRR methodology more accurately forecasts avoided costs for non-standard QFs where the specific characteristics of the resources in question outweigh the administrative burden that forms the basis for maintaining standard avoided costs for QFs. The relevant issue is not whether using the PDDRR methodology and the GRID model to inform inputs to the RVOS calculation results in lower or higher prices than using standard costs; the relevant issue is whether the PDDRR methodology and the GRID model produce a more accurate forecast of avoided costs, which they do. A sophisticated model is necessary to accurately account for the wide-ranging

[41] Order No. 17-357 at 4.
[42] Order No. 17-357 at 4.

conditions experienced in actual operations. This is the basis for the detailed examination of the characteristics of solar resources being undertaken in this docket.

In addition, sophisticated models are increasingly necessary as the proportion of PacifiCorp's load met with intermittent solar and wind resources increases. The proportion of regional load met by these resources is also relevant as it drives volatility in market prices, increasing the value of flexible resources and reducing the value of uncontrollable resources. As experience with these effects grows, I anticipate that GRID model inputs and assumptions will need to become more sophisticated. While GRID is used for determining avoided cost pricing, it is first and foremost used to set the rates paid by retail customers, whom also pay for QF purchases and receive the associated benefits from QF generation. Ultimately, the GRID model and PDDRR methodology need to be sufficiently sophisticated to ensure retail customers pay just and reasonable rates. Finally, as noted above, PacifiCorp is willing to provide workpapers and access to its GRID model to interested parties who sign a non-disclosure agreement, just as it does in rate case proceedings and for qualifying facility developers today.

Q. What do you recommend with regard to the RVOS calculation?

A. The PDDRR methodology uses the most up-to-date information and more accurately represents the individual and aggregate impacts proposed resources have on PacifiCorp's overall portfolio. While frequent updates can help ensure that results continue to accurately reflect the company's avoided costs, all forecasts diminish in accuracy as they go further into the future.

Q. Does this conclude your testimony?

A. Yes.

Docket No. UM 1910
Exhibit PAC/200
Witness: Kevin C. Putnam

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Direct Testimony of Kevin C. Putnam

November 2017

DIRECT TESTIMONY OF KEVIN C. PUTNAM
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ATTACHED EXHIBIT

Q. Please state your name, business address, and present position with PacifiCorp d/b/a Pacific Power.

A. My name is Kevin C. Putnam. My business address is 63820 Clausen Drive Suite 100, Bend, Oregon 97702. My title is Director, Field Engineering-West.

QUALIFICATIONS

Q. Briefly describe your education and professional experience.

A. I received a Bachelor of Science in Electrical Engineering from the University of Idaho in 2002. I have worked for PacifiCorp for 15 years. I started working in substation engineering, and then worked in field operations management. I have been in my present position as the director of field engineering for four years. In my current role, I work with field engineers who perform distribution system planning and provide operational support.

PURPOSE AND SUMMARY OF TESTIMONY

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

A. My testimony explains the inputs in the resource value of solar (RVOS) methodology as directed by the Public Utility Commission of Oregon (Commission) in Order No. 17-357. Specifically, I address inputs for two elements in the RVOS calculation: avoided transmission and distribution (T&D) capacity, and avoided line losses. First, I will explain what PacifiCorp has included in the RVOS for avoided transmission and distribution capacity and how it was calculated. Second, I discuss how the granularity of the avoided transmission and distribution capacity can be advanced. Finally, I describe what PacifiCorp has included in the RVOS for avoided line losses and how it was calculated.

AVOIDED TRANSMISSION AND DISTRIBUTION CAPACITY

Q. Please describe the Commission's direction regarding calculating avoided transmission and distribution capacity.

A. The Commission directed utilities to "use a system-wide average of the avoided or deferred costs of expanding, replacing or updating T&D infrastructure attributable to incremental solar penetration in Oregon service areas" in its initial compliance filing.[1] The Commission noted that "avoided costs need not be specifically limited to growth related-investments" and clarified that utilities may continue to use its Marginal Cost of Service Study for the "first version of RVOS."[2]

Q. Please explain what PacifiCorp included as avoided transmission and distribution capacity in the RVOS and how this was calculated.

A. In 2016, PacifiCorp updated its transmission and distribution deferral calculation for the analysis of demand-side management resources in the 2017 Integrated Resource Plan (IRP). PacifiCorp used the values from this calculation for this element in the RVOS. These values were calculated to represent the average deferral value of transmission and distribution investments based on forecasted capacity additions and projected costs of the projects. The values used in the initial calculation of the RVOS are provided in Exhibit PAC/201 and reflect a transmission deferral value of $5.94/kilowatt (kW)-year, based on system-wide transmission capacity projects, and a distribution deferral value of $13.44/kW-year based on distribution capacity increase projects in Oregon.

[1] *In the Matter of Public Utility Commission of Oregon Investigation to Determine the Resource Value of Solar*, Docket No. UM 1716, Order No. 17-357 (Order No. 17-357) at 8-9 (Sep. 15, 2017).
[2] Order No. 17-357 at 9.

Q. How do the transmission and distribution deferral values apply to RVOS resources?

A. One megawatt (MW) of solar resource is unlikely to enable deferral of an entire megawatt of transmission or distribution. Instead, a capacity contribution value is used to adjust the transmission and distribution deferral for a specific RVOS resource's generation profile. This is analogous to the capacity contribution applicable to generation capacity deferral; however, different capacity contribution values are appropriate to better reflect the location-specific nature of transmission and distribution deferrals, rather than the system-wide load and resource balance applicable to generation capacity deferral. In particular, transmission and distribution elements must be operated in accordance with reliability standards at all times. System changes that reduce transmission or distribution loading during only a portion of the day would not be able to defer required upgrades. Because of the diurnal nature of solar generation and the uncertainty in its output, there are limited circumstances in which solar resources can defer transmission and distribution upgrades. Of 33 transmission upgrade projects currently in the planning stages in Oregon with in-service dates after 2018, only two have transmission loading profiles for which solar resources would likely provide at least one year of deferral to the project in-service date. Because PacifiCorp's planned transmission upgrades in Oregon are primarily intended for reliability compliance, in many cases solar resource additions will not be viable solutions due to their uncertain output. In light of this, while the company will continue to evaluate solar resources as alternatives to transmission upgrades on a case-by-case basis, it has included a transmission capacity contribution of zero in the RVOS model.

Since North American Electric Reliability Corporation reliability standards do not apply to distribution system assets, solar is more likely to be a potentially viable alternative at the distribution system level. However, of 13 Oregon substation capacity upgrade projects evaluated by the company, solar generation profiles only produced a viable alternative in one instance. In this analysis, solar was able to defer three MW of expected substation capacity upgrade needs starting in 2023 out of 50 MW of total need over the next 10 years. The amount of solar necessary to defer substation capacity is dependent on solar output during the period of highest loading. In the one instance where solar was a viable alternative, peak loading was expected to occur in hour 17 in July and August, so the expected capacity factor of a solar resource during those intervals determines the distribution capacity contribution. In addition, because solar generation is uncertain, the company's distribution planning analysis assumes solar resources are constructed to provide 10 percent more distribution capacity deferral than is needed.

GRANULARITY OF AVOIDED TRANSMISSION AND DISTRIBUTION CAPACITY

Q. Please describe how the avoided transmission and distribution capacity element could be adapted to advance the granularity of this element in the future.

A. In Order No. 17-357, the Commission directed utilities to address how to advance the granularity and location-specific value for this element.[3] PacifiCorp's distinct service

[3] Order No. 17-357 at 9 and 21.

territory, planning procedures, and data availability inform its T&D deferral calculation, and PacifiCorp agrees with the Commission that "the value of solar and other distributed energy resources differ between geographic locations based on the specific transmission and distribution system characteristics in that area."[4] PacifiCorp also agrees with Staff's statement that "a single solar PV array may not defer a T&D investment, but several systems on the same feeder could contribute to the deferral."[5] PacifiCorp considered the distribution feeder level for its proposal to increase the granularity of the transmission and distribution deferral element in these comments. PacifiCorp continues to examine the potential for transmission and distribution deferral at the feeder level. I provide an overview of PacifiCorp's proposed approach to calculating the impact of solar resources on transmission and distribution deferrals below.

Q. Does PacifiCorp evaluate solar resources as a potential solution to transmission and distribution infrastructure needs?

A. Yes. PacifiCorp has developed a distributed energy resource screening tool to evaluate solar, energy storage, and demand-side management as a potential solution for system reinforcement projects. Capacity-increase projects that are identified and submitted into the 10-year capital planning process are evaluated utilizing the tool.

Q. Does the distributed energy resource screen analyze the coincidence of the resource to the daily load profile?

A. Yes. The distributed energy resource screen is based on the loading of the specific transmission or distribution element under consideration and evaluates the

[4] Order No. 17-357 at 9.
[5] Order No. 17-357 at 8.

coincidence of the solar generation profile to determine if the resource is a suitable solution.

Locational Transmission Deferral Value

Q. Please describe how PacifiCorp proposes to create a locational transmission deferral value.

A. PacifiCorp's proposed approach is to create a distinct transmission capacity deferral value for each load forecast pocket. A load forecast pocket is based on the transmission topography, load center and geographic relationship.[6]

Q. How does PacifiCorp propose to address load forecast pockets that have an identified transmission capacity increase project?

A. PacifiCorp would apply a transmission deferral credit, starting in the year of the expected start of the transmission capacity increase project. The credit would be applied to a resource's generation profile based on the capacity contribution to the transmission deferral. For transmission capacity-increase projects that the company has performed a distributed energy resource screen that indicates solar is ineffective in meeting the identified capacity need, the company would not apply a transmission deferral credit.

Q. How does PacifiCorp propose to address when it becomes necessary to start work on a transmission capacity-increase project to meet the projected capacity need?

A. Once the company has committed to a transmission capacity-increase project to meet

[6] Additional information on load pockets can be found in PacifiCorp's biennial transmission plan, publicly available on OASIS at the link: http://www.oasis.oati.com/PPW/PPWdocs/PacifiCorp_Local_Transmission_System__Plan_Report_120815.pdf.

the projected capacity need, the company would no longer include a transmission deferral credit. If the company continued to include the transmission deferral credit this would be equivalent to "double-paying" for the transmission capacity.

Q. How does PacifiCorp propose to address the transmission deferral value in other load forecast pockets?

A. The remaining load forecast pockets would not have an associated transmission capacity project for potential deferral so the company would set the transmission deferral value to zero.

Locational Distribution Deferral Value

Q. Does PacifiCorp have a proposal to create a locational distribution deferral credit?

A. Yes. PacifiCorp's proposal contains two views of distribution feeders. PacifiCorp proposes to look at the individual distribution feeders and the combination of distribution feeders at the distribution substation transformer level. This is necessary due to the potential for deferral of distribution **line** capacity-increase projects and distribution **substation** capacity-increase projects. Distributed energy resources, in this case solar, installed on an individual distribution feeder could potentially defer a capacity-increase project on that specific feeder. In the case of the distribution substation capacity-increase projects, the collection of feeders normally served by the distribution substation transformer could contribute to the deferral of this type of capacity-increase project.

Q. How does the company propose to address distribution feeders at the individual feeder level?

A. For distribution feeders that have an identified capacity-increase project and the distributed energy resource screen indicates a solar resource is a valid alternative, the company would include the distribution deferral value for that location and allocate on the calculated distribution capacity contribution.

The intended application of the RVOS model will likely determine whether the difference between project-specific deferral values and system-average deferral values is significant enough to justify the administrative burden of calculating and applying individual project-specific deferral values. Where the intent is to procure resources to avoid a particular upgrade, project-specific values are certainly appropriate. Where the intent is to set system-wide rates, a less granular look will likely be sufficient, though it will not provide the same incentive to locate resources in the most valuable locations.

Q. How does PacifiCorp propose to address the remaining distribution feeders?

A. For distribution feeders with no forecasted capacity issues there would not be a distribution capacity increase to defer, thus the distribution deferral value is zero.

Q. How does PacifiCorp propose to address distribution feeders at the distribution substation transformers level?

A. For distribution substation transformers with an identified capacity-increase project and where the distributed energy resource screen indicates solar is a valid solution, PacifiCorp will apply a distribution deferral starting in the year of the identified project. For other locations, the distribution deferral value is zero.

AVOIDED LINE LOSSES

Q. Please describe the Commission's direction regarding calculating avoided line losses.

A. The Commission asked "utilities to develop hourly averages of line losses by month for the daytime hours when load on the system is higher, losses are greater, and solar is generating."[7] The Commission noted that it "expect[s] the utilities' values to recognize and reflect that there are seasonal and daily variations in line loss impacts with higher temperatures and higher loads having higher losses."[8] The Commission clarified that it does not "expect a true hourly value to this element, but ask[s] the utilities to provide the most granular value they reasonably can inclusive of daytime and seasonal variation."[9]

Q. Please explain how PacifiCorp addressed this element.

A. PacifiCorp began with the transmission, primary, and secondary losses currently reflected in retail rates, which reflect the company's most recent line loss study. For the RVOS line loss element, PacifiCorp conducted power flow studies that identified the primary and secondary line losses at 100 percent, 90 percent, and 75 percent of both winter and summer peak loads to supplement the previous study. These losses were then fitted to a 12 month and 24-hour profile to create the marginal losses for resources connected at either the primary or secondary voltage level.

[7] Order No. 17-357 at 10.
[8] Order No. 17-357 at 10.
[9] Order No. 17-357 at 10.

Q. Please explain why PacifiCorp's approach is the most granular value that can be used inclusive of daytime and seasonal variation at this time.

A. PacifiCorp's methodology reasonably recognizes the variation of line losses with respect to seasonality, time of day and peak load, and is in accordance with the guidance provided by the Commission. Calculating and administering location-specific line losses would require significant time and effort for what is expected to be a minor improvement in the results since this is a small component of the resource value of solar.

Q. Please explain how the line loss values will be applied in the RVOS calculation.

A. Line loss benefits are highest when generation is offsetting local load and those benefits decrease when generation is exported across various segments of the electric grid. PacifiCorp's line loss element proposal therefore reflects whether output is fully utilized behind the meter, exported to the secondary distribution system, exported to the primary distribution system, or exported to the transmission system. Output that is fully utilized behind a customer's meter would receive credit for avoided line losses based on the customer's interconnection voltage level (transmission, primary, or secondary). Output to the distribution or transmission system would receive lower credit for avoided line losses based on the next higher voltage level, based on expected distribution feeder and substation loading. A resource connected at the secondary level would thus receive credit for avoided secondary line losses for output used behind the meter, credit for avoided primary losses for output exported to the secondary distribution system, credit for avoided transmission losses for output exported to the primary distribution system, and no credit for avoided output exported to the transmission system.

Q. What is the status of PacifiCorp's implementation of the proposals for transmission and distribution deferral and line losses mentioned above?

A. PacifiCorp has developed the concept and created a simplified tracking spreadsheet that could be used to capture the data needed for these proposals. Next, the company would need to perform the screening and would allocate the associated cost in the administrative cost element to compile the necessary distribution feeder information.

Q. Do you have any additional comments?

A. Yes. It is possible that the company could incur incremental costs depending on the application of the RVOS and the type of interconnection installed in accordance with applicable rules. An example of these incremental costs PacifiCorp can incur are in net metering interconnections that pass level two interconnection reviews, and do not move to a level three interconnection review. For this level of interconnection, cost responsibility is limited to minor modifications. PacifiCorp proposes that allocation of these incremental transmission and distribution costs follow the principles of the company's existing line extension rule.

Q. Does this conclude your testimony?

A. Yes.

Docket No. UM 1910
Exhibit PAC/201
Witness: Kevin C. Putnam

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Kevin C. Putnam

Transmission and Distribution Deferral Value

November 2017

PacifiCorp

Transmission and Distribution Deferral Value

T&D Deferral Value	**Capital Investments**	**MVA Added**	**$/MVA**	**Power Factor**	**$/KW**	**Real Carrying Charge**	**$/KW-year**
Transmission Deferral Value	$219,235,659	2,375.0	$92,310	0.95	$97.17	6.11%	$5.94
Distribution Deferral Value	$28,532,998	147.5	$193,444	0.95	$203.63	6.60%	$13.44
Total T&D Deferral Value							$19.38

*__Capital Investments/MVA Added__ - Planned system-wide transmission upgrades and Oregon distribution upgrades

*__Power factor__-standard value

*__Real Carrying Charge__-The real levelized T&D carrying charges based on the incremental cost of capital