

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

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

6 **QUALIFICATIONS**

7 **Q. Briefly describe your education and professional experience.**

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

17 **PURPOSE AND SUMMARY OF TESTIMONY**

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

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

- 22 1. Avoided energy cost;
- 23 2. Avoided generation capacity cost;

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

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

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

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

18 **Q. Please provide a summary of your testimony.**

19 A. I explain the calculation of each RVOS element, describing how PacifiCorp complied
20 with the directives and guidance in Order No. 17-357, and I also provide additional
21 discussion on the derivation of these elements. Overall, PacifiCorp guided its
22 approach for the RVOS calculation by adhering to underlying principles of accuracy,
23 transparency, flexibility and continuous improvement. To demonstrate the

1 application of the RVOS calculation, PacifiCorp created an indicative RVOS resource
 2 based on a simple average of expected generation profiles for fixed-tilt solar
 3 resources at three locations in its Oregon service territory: the Willamette Valley;
 4 Southern Oregon; and Central Oregon.

5 Table 1 shows 25-year nominal-levelized results by RVOS element starting in
 6 2018 for this indicative resource. For comparison, results are shown based on the
 7 standard avoided costs, as ordered by the Commission, as well as based on
 8 PacifiCorp’s Partial Displacement Differential Revenue Requirement (PDDRR)
 9 methodology, which the company proposes as a more up-to-date and accurate
 10 forecast of the value of solar.

11 **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

1 **OVERVIEW**

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

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

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

14 A. The RVOS methodology should be a flexible tool capable of customization for
15 specific applications and incorporating currently available information for each
16 utility. The Commission recognized the need for flexibility and evolution of the
17 RVOS calculation, noting that while “the first version of RVOS is meant to be
18 generally applicable to a solar system installed by a retail, mass market customer
19 today” the Commission has “not prejudged any applications.”¹ PacifiCorp also
20 understands that the RVOS will likely inform valuation of community solar projects,²
21 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.

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

5 **Q. The Commission has not yet determined how often the RVOS should be**
6 **updated, but noted that it “will decide later, based on application, whether**
7 **RVOS should be updated annually or every two years.”³ What is PacifiCorp’s**
8 **position on this issue?**

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

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

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

³ Order No. 17-357 at 17.

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

4 **AVOIDED ENERGY**

5 **Q. Please describe how PacifiCorp complied with the Commission’s direction**
6 **regarding the calculation of avoided energy costs.**

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

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

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

17 **Standard Qualifying Facility Avoided Energy Costs**

18 **Q. What are PacifiCorp’s current standard non-renewable avoided energy costs?**

19 A. During the sufficiency period, PacifiCorp’s current standard non-renewable avoided
20 energy costs are based on a blend of the forward prices for the Mid-Columbia,
21 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.

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

5 During the deficiency period, PacifiCorp's current standard non-renewable
6 avoided energy costs are based on the variable costs of the same combined cycle
7 combustion turbine (CCCT) used to set avoided generation capacity values. The
8 variable fuel costs for this proxy resource are based on forward natural gas prices.
9 PacifiCorp's currently approved standard non-renewable QF avoided cost became
10 effective on June 1, 2017 (June 2017 standard avoided cost). The June 2017 standard
11 avoided costs reflect PacifiCorp's March 2017 official forward price curve (OFPC),
12 blending ratios prepared in April 2017 and the heat rate of the proxy CCCT from the
13 2015 Integrated Resource Plan (IRP).

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

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

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

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

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

6 **Hydro Conditions**

7 **Q. The Commission asked utilities to explain and provide “statistical analysis**
8 **demonstrating how their energy values are scaled to represent the average price**
9 **under a range of hydro conditions.”⁷ Please summarize PacifiCorp’s approach.**

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

⁷ Order No. 17-357 at 5.

1 **Q. Please explain the proposed hydro condition methodology.**

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

14 To calculate the impact of a range of hydro conditions, PacifiCorp prepared
15 two additional forward price curves using hydro generation inputs consistent with wet
16 and dry hydro conditions, rather than normal hydro conditions. PacifiCorp identified
17 1992 and 1999 as the dry and wet years, respectively, based on the hydro generation
18 within the Pacific Northwest as reported by the Energy Information Administration
19 and as shown in Figure 1. Hydro generation in 1999 was 25 percent higher than the
20 average for 1990 through 2015, while hydro generation in 1992 was 15 percent lower.
21 The change in prices in the wet and dry hydro studies relative to the Aurora results
22 under normal hydro conditions was calculated for each market, by month, and on-
23 and off-peak period. The average hydro generation during wet years in the historical

1 period was 19 percent more than the historical average, somewhat less than the 25
2 percent deviation in the 1999 wet price curve. While 27 percent of the historical
3 period was designated as wet years, they are less wet than 1999, so the weighting of
4 the wet price curve based on 1999 is reduced proportionately. Similarly, the average
5 hydro generation during dry years in the historical period was 13 percent less than the
6 historical average, which is slightly less extreme than the 15 percent deviation
7 represented in the 1992 dry price curve. While 38 percent of the historical period was
8 designated as dry years, they are less dry than 1992, so the weighting of the dry price
9 curve based on 1992 is reduced proportionately. The weighting of the normal price
10 curve is adjusted to offset the changes in the weighting of the wet and dry price
11 curves.

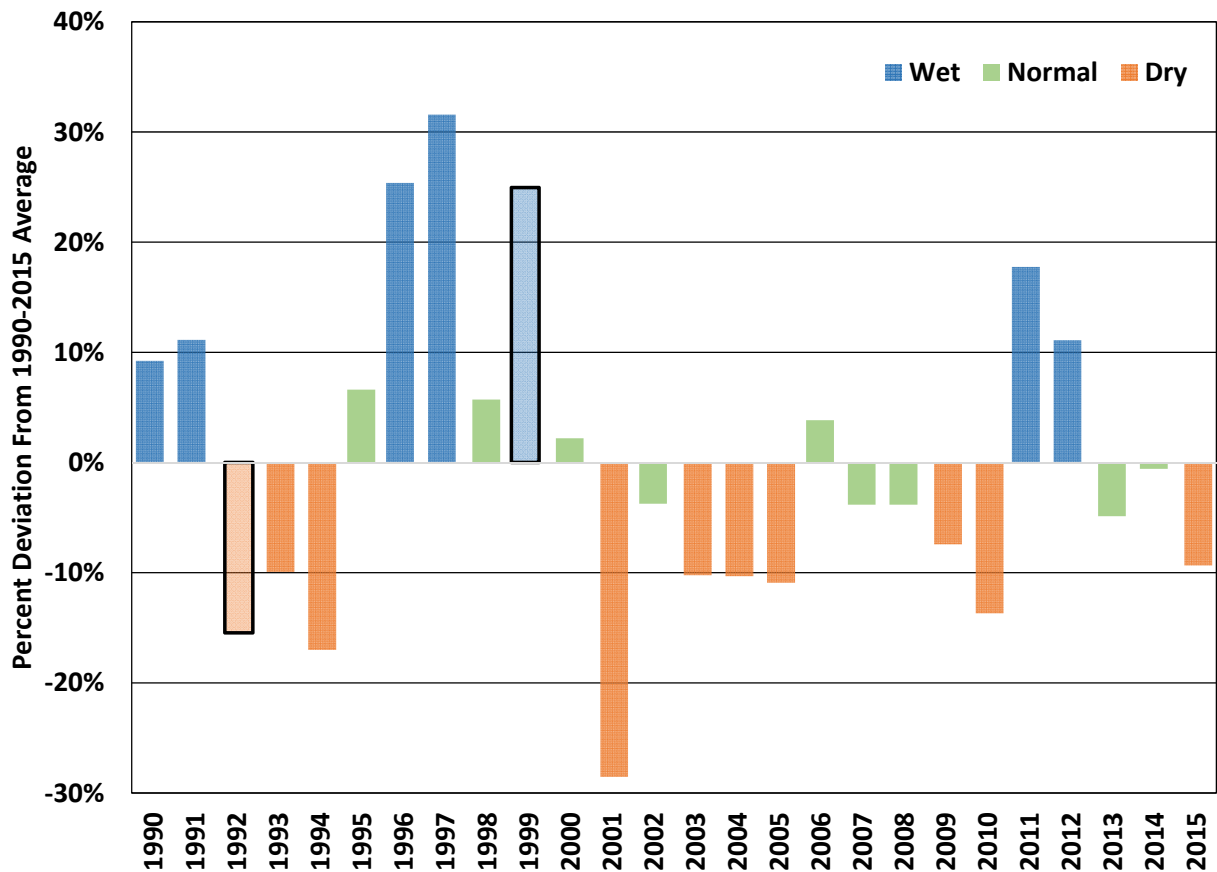
12 After accounting for the range of wet, normal, and dry conditions over all
13 years between 1990 and 2015, the market prices based on wet conditions represented
14 by 1999 were given a 20 percent weighting⁸ and the market prices based on dry
15 conditions represented by 1992 were given a 33 percent weighting,⁹ with market
16 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%

1

Figure 1: Pacific Northwest Hydro Conditions, 1999-2015



2 **Q. What is the result of PacifiCorp’s hydro condition adjustment?**

3 A. From 2018 through 2027, the hydro condition adjustment results in an average market
 4 price reduction of 0.8 percent at Mid-Columbia and 0.1 percent at COB, and an
 5 average market price increase of less than 0.1 percent at Palo Verde. There is no
 6 adjustment during the deficiency period, as avoided energy costs are not based on
 7 electricity prices during that timeframe. After accounting for the blending ratios used
 8 in standard rates, the impact on avoided energy costs is a reduction of less than one
 9 percent.

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

11 A. Because of the minimal impacts from these adjustments, PacifiCorp proposes to

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

11 **Hourly Price Shape**

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

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

19 In the second stage, monthly prices are shaped to hourly values. PacifiCorp's
20 OFPC includes on- and off-peak granularity, but does not include hourly granularity.
21 Distinguishing between on- and off-peak hours is not necessary because solar
22 generation is not correlated with weekdays, weekends, and holidays, so the on- and
23 off-peak values are combined to a single monthly average price. To create an hourly

1 shape, PacifiCorp proposes using the results of Energy Imbalance Market (EIM)
2 operations. Specifically, PacifiCorp proposes using 15-minute EIM market prices for
3 the most recent 12 month period, in this instance, the 12 months ending September
4 2017.

5 Under this approach, hourly shaping would be based on EIM load aggregation
6 point (LAP) prices, with Mid-Columbia hourly shaping based on the PacifiCorp west
7 (PACW) LAP, Palo Verde hourly shaping based on the PacifiCorp east (PACE) LAP,
8 and COB hourly shaping based on the Malin LAP. The market price shape is a
9 “scalar” based on the average market prices in a month during a given hour, relative
10 to the average market price in that month during all hours. For instance, if the
11 average market price during hour-ending 10 in May is \$18/MWh, and the average
12 market price during all hours in May is \$20/MWh, then the scalar for hour-ending 10
13 in May would be 90 percent.¹⁰ Before the monthly shape from the OFPC is
14 incorporated, the average of the 24 hourly scalars for a given month is always
15 100 percent. Similarly, when the monthly and hourly shapes are combined, the
16 hourly market price shapes average to one over the course of each year.

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

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

¹⁰ \$18/MWh / \$20/MWh equals 90 percent.

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

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

11 A. PacifiCorp selected the most recent year of actual results because it more accurately
12 reflects expected future conditions than data from earlier periods and is the minimum
13 timeframe necessary to identify specific conditions for each month of the year. Both
14 PacifiCorp and the western interconnect as a whole have experienced a significant
15 increase in the number of solar resources, including additional solar resources in the
16 last 12 months, and this trend is expected to continue over the next several years.¹¹
17 This trend of increased solar resources has a meaningful impact on market price
18 shapes, an impact that is acknowledged by the Commission's inclusion of market
19 price response element in the RVOS methodology. Because of the diurnal nature of
20 solar, its impact on the market is different from other variables that impact market
21 prices, such as load, hydro conditions, or natural gas prices. For those other
22 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.

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

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

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

14 Current EIM regulations restrict settlement prices to energy values between
15 +\$1,000/MWh and -\$150/MWh, with these values typically occurring only when the
16 calculated EIM dispatch solution is infeasible, such as when all other resource options
17 in the model have been deployed. A single hour with prices approaching either of
18 these values will have an appreciable impact on the monthly average for that hour
19 since there are only about 30 days in a month. These prices are generally a result of
20 unexpected conditions, which may include significant deviations from forecasted
21 load, wind, or solar. Such deviations are largely random, so the presence of extreme
22 values is generally a chance occurrence, rather than a characteristic of a given hour.
23 PacifiCorp is therefore proposing that the EIM prices used to calculate the 12x24

1 scalars be capped at +\$200/MWh and -\$50/MWh. This balances the evidence that
 2 extreme events did occur in particular hours, with the likelihood that such events
 3 could occur in any hour.

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

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

12 **Figure 2: PACW Hourly Market Scalars by Month**

Period Month	Hour																							Avg	
	LLH					HLH															LLH				
	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

13 **Q. What is the final result of PacifiCorp’s proposed hourly market price shaping**
 14 **methodology?**

15 A. The EIM hourly scalars based on PACW, PACE, and Malin are combined using the
 16 market blending ratios applicable to standard avoided costs and the result is
 17 multiplied by the applicable monthly scalars from PacifiCorp’s OFPC to produce

1 distinct market price scalars for each year. These values are applied to an annual
 2 price, so the scalars for each year average to one. The resulting hourly market scalars
 3 for 2019 are shown in Figure 3.

4 **Figure 3: RVOS Hourly Market Scalars for 2019**

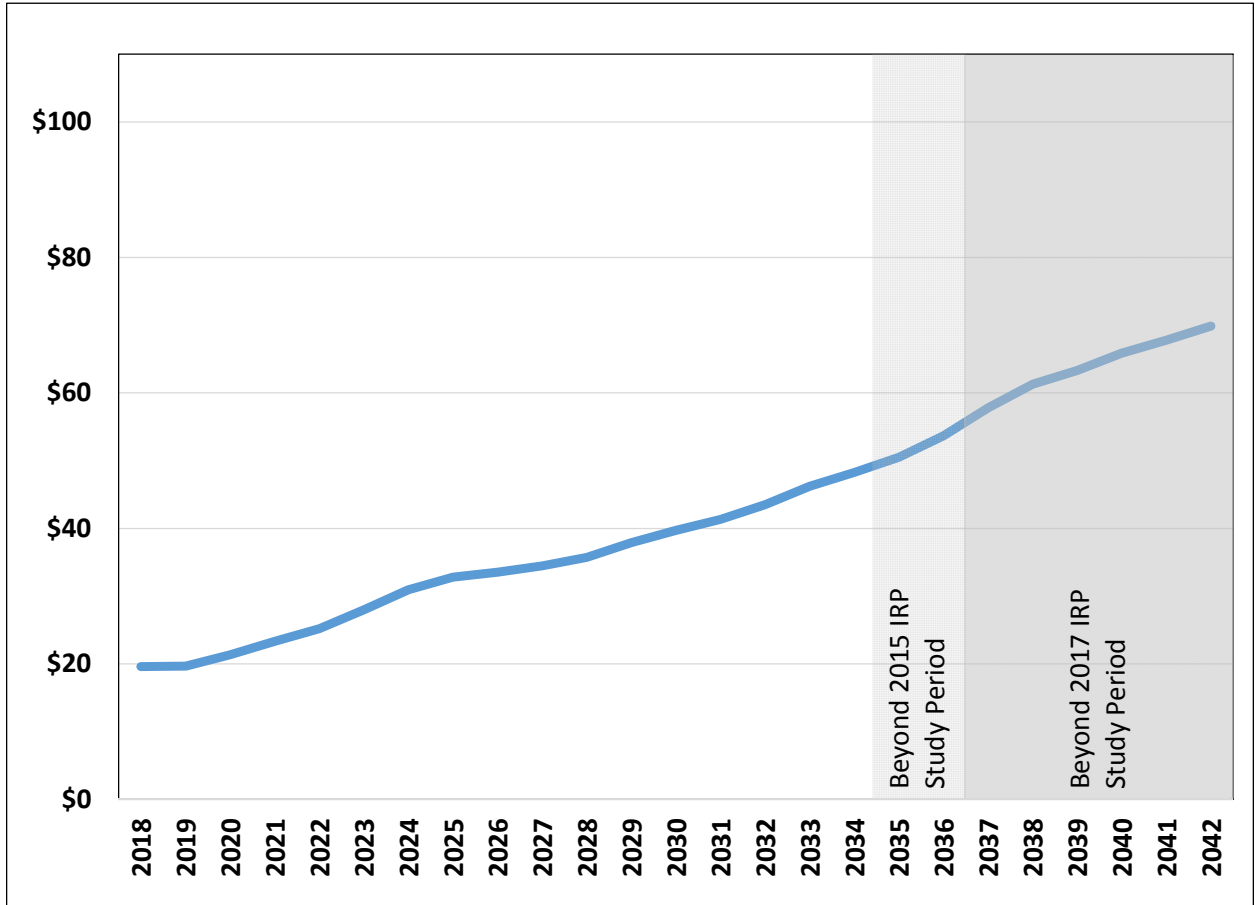
Period Month	Hour																							Avg	
	LLH						HLH															LLH			
	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22		23
1	1.0	0.9	0.9	0.9	1.0	1.1	1.3	1.6	1.4	1.2	1.2	1.0	0.8	0.8	0.8	0.9	1.2	1.7	1.6	1.5	1.6	1.4	1.3	1.1	1.2
2	1.0	0.9	1.0	1.0	1.0	1.3	1.4	1.8	1.5	1.2	0.9	0.8	0.7	0.8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

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

6 A. Figure 4 below shows the average annual avoided energy costs for the indicative
 7 RVOS resource. This reflects the combination of the annual energy cost and the
 8 hourly price shapes consistent with the indicative resource’s generation profile.

9 Years that extend beyond the study period considered in the company’s IRP analysis
 10 are shown for reference.

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



2 **AVOIDED COST UPDATES**

3 **Q. The Commission acknowledges concerns about tying RVOS energy values to**
4 **litigated QF avoided cost filings, but notes that it is too early to decide whether**
5 **QF avoided costs and RVOS should be “synched” with their updates.¹² What is**
6 **PacifiCorp’s position on this issue?**

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

¹² Order No. 17-357 at 4.

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

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

16 **AVOIDED GENERATION CAPACITY**

17 **Q. Please explain how PacifiCorp addressed this element.**

18 A. The Commission directed utilities to “determine the capacity value consistent with
19 the Commission's standard non-renewable QF avoided cost guidelines.”¹³ Consistent
20 with the Commission’s directive for utilities to “provide capacity value and timing
21 (deficiency date) in line with their current approved standard non-renewable QF
22 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.

1 avoided cost capacity value.

2 PacifiCorp's current avoided capacity costs are based on the fixed cost of a
3 CCCT from the 2015 IRP, beginning at \$149/kilowatt (kW)-year starting in 2028, and
4 increasing at inflation thereafter. The capacity value and deficiency date in the
5 June 2017 standard avoided costs were approved following acknowledgment of the
6 2015 IRP. In accordance with Order No. 14-058, the capacity value of a standard QF
7 resource is calculated by multiplying the annual fixed costs of the proxy CCCT by the
8 capacity contribution of the QF resource from the acknowledged IRP.¹⁵

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

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

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

20 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/PacificCorp_2015IRP-Vol2-Appendices.pdf.

1 include a range of generation profiles, a single capacity contribution value is unlikely
2 to be a reasonable representation for all solar resources. Instead, capacity
3 contribution value for a proposed resource or set of resources can be determined
4 based on the 12x24 LOLP results from the IRP capacity contribution study.
5 Specifically, the capacity value of a proposed resource would be weighted based on
6 the LOLP in each hour. Under this approach, a resource delivering in all hours would
7 have a 100 percent capacity contribution and 100 percent avoided capacity cost, as
8 would a resource that only delivered in those hours in which LOLP was greater than
9 zero. A solar resource would receive a capacity contribution based on its expected
10 output during those hours with LOLP greater than zero.

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

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

1 **Resource-Balance Year**

2 **Q. The Commission directed utilities to “remove incremental distributed solar PV**
3 **from the load forecast in the initial filing.”¹⁷ Specifically, the Commission**
4 **directed utilities to use the “last acknowledged IRP resource-balance year, and**
5 **then remove new incremental expected distributed solar PV from that forecast,**
6 **and then if applicable, provide an adjusted deficiency date.”¹⁸ Please describe**
7 **the company’s approach.**

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

20 **AVOIDED TRANSMISSION AND DISTRIBUTION CAPACITY**

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

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

¹⁷ Order No. 17-357 at 8.

¹⁸ *Id.*

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

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

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

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

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

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

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

AVOIDED LINE LOSSES

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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

1 costs only. The effect of losses on the avoided generation capacity and transmission
2 and distribution deferral elements is included in those elements and not broken out.

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

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

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

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

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

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

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

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

7 **ADMINISTRATION**

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

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

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

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

¹⁹ Order No. 17-357 at 10.

²⁰ Order No. 17-357 at 10.

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

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

6 A. PacifiCorp employed a similar methodology for administration costs as that used for
7 its net metering program in Utah. PacifiCorp dedicates a department to the
8 administration of the customer generation resources it oversees and implements
9 across the six states that it serves, which includes handling and processing
10 interconnection applications. For this calculation, the overall expense of this
11 department for 2016 was multiplied by the proportion of total capacity installed in
12 2016 in the Oregon net metering program. This amount was then reduced by the
13 application fees received by certain net metering participants. This amount was then
14 divided by the total interconnected capacity, which results in a one-time cost of \$7.95
15 per installed kW. This and the other administrative costs below refer to delivered
16 alternating current (AC) capacity, with direct current installation capacity converted
17 to AC using a ratio of 0.85.

18 In addition to the administrative costs from the dedicated customer generation
19 department, PacifiCorp has estimated costs from the billing and customer service
20 departments related to initial setup and interconnection of customers who choose to
21 participate in the net metering program. This captures the costs of net metering
22 specific customer calls, the processing of meter exchanges and transitioning
23 customers to modified net metering billing. Similar to the customer generation

1 department specific costs, the total costs from 2016 were divided by the total
2 interconnected capacity to establish a cost of \$1.48 per installed kW.

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

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

16 A. The costs in this category are related to the additional administration and billing
17 support required to facilitate net metering participation. These are costs related to
18 manual review of net metering bills, tracking of excess generation credits from month
19 to month, and manually computing aggregated billing. Unlike the one time
20 administrative and engineering costs associated with the interconnection of
21 generating facilities and the transition to net metering rates that can be clearly
22 assigned to the projects that interconnect within a specific year, these costs are
23 attributable to all currently existing private generation. In order to reflect this

1 difference, PacifiCorp calculated the average capacity of all projects interconnected
2 in Oregon, rather than then the total new projects interconnected in 2016. The total
3 billing support amount for 2016 was then divided by this average interconnected
4 capacity amount to provide an annual billing support fee, producing an annual billing
5 support fee of \$1.61 per kW.

6 **Q. Please explain how incremental distribution investment was calculated.**

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

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

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

1 yields a 25-year levelized administrative cost of \$2.88/MWh for the indicative RVOS
2 resource.

3 INTEGRATION

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

7 A. Not at this time. However, a Flexible Reserve Study that included solar integration
8 costs was prepared as part of the 2017 IRP and is currently pending acknowledgment
9 by the Commission.²² Because the Commission will consider acknowledgment of the
10 2017 IRP shortly after this filing in early December, PacifiCorp included its solar
11 integration costs from the 2017 IRP, but can adjust in the future if necessary.

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

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

15 **Q. While the Commission noted that “very few solar systems are currently installed**
16 **with storage” it invited The Alliance for Solar Choice to file a proposal on how**
17 **the Commission could value solar paired with storage in this proceeding.²³**

18 **What is PacifiCorp’s position on combining solar and storage to reduce**
19 **integration costs?**

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

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.

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

16 MARKET PRICE RESPONSE

17 **Q. Please describe the Commission’s direction regarding the inclusion of market**
18 **price response.**

19 A. The Commission directed staff to coordinate the use of E3’s model to create a proxy
20 value for market price response for utilities to use.²⁴ The Commission noted that
21 “utilities should not assume this value is zero, unless there is firm evidence that a
22 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.

1 **Q. Please describe the value included in PacifiCorp’s calculation of the market**
2 **price response.**

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

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

²⁶ Order No. 17-357 at 22.

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

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

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

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

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

AVOIDED HEDGE VALUE

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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

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

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

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

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

18 In the preferred portfolio, shadow prices for carbon dioxide emissions average
19 around \$6 per ton from 2024 through 2028. Starting in 2029, coal retirements and
20 renewable resource additions reduce emissions below the Mass Cap B threshold, so
21 the shadow price for carbon dioxide emissions drops to zero. After accounting for the
22 heat rate and emissions rate of the proxy plant, the shadow price for carbon dioxide
23 emissions in 2028 equates to a cost of \$2.36 per MWh of output. For the reasons

1 described above, 2028 is the only year in which the avoided resource emits carbon
2 dioxide and there is a positive price on emissions. Environmental compliance values
3 based on the Mass Cap B shadow prices and the assumed emissions rate of the
4 avoided CCCT have been included in the ordered RVOS calculation for informational
5 purposes only.

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

8 A. Yes. PacifiCorp developed an alternative value reflecting the PDDRR methodology.
9 Unlike the standard avoided cost methodology, the PDDRR methodology identifies a
10 range of avoided resources including coal and gas resources as well as market
11 transactions. As a result, an RVOS resource can impact emissions during the
12 sufficiency period. During the deficiency period, rather than assuming a one-to-one
13 relationship between RVOS resource output and the proxy resource, the PDDRR
14 methodology accounts for the emissions of PacifiCorp's entire portfolio and the
15 generation profile of the proposed resource relative to the capacity equivalent output
16 of a proxy resource from the preferred portfolio. Under this alternative methodology,
17 the Mass Cap B shadow prices from the 2017 IRP preferred portfolio are applied to
18 the forecasted emissions reduction resulting from the RVOS resource, but only when
19 PacifiCorp's emissions are forecasted to exceed the Mass Cap B annual limits. The
20 PDDRR methodology results in carbon dioxide emissions that exceed the Mass Cap
21 B limit in 2024 and 2027, with avoided environmental compliance values of
22 \$2.09/MWh and \$1.82/MWh, respectively, in those years.

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

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

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

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

16 **AVOIDED RPS COMPLIANCE**

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

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

³⁰ Order No. 17-357 at 13.

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

2 A. Yes.

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

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

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

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

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

6 GRID SERVICES

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

8 A. The Commission renamed "security, reliability, and resiliency" to "grid services" and
9 moved ancillary services to this element.³¹ The Commission directed utilities to
10 include a zero value for this element.³² The Commission "retain[ed] this element to
11 capture the potential incremental system benefits from solar in the future"³³ and
12 invited Renewable Northwest or other parties "to make a proposal for valuing enabled
13 smart inverters based on best practices or other utility experiences, and how the
14 utilities could capture this value."³⁴

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

16 A. Yes.

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

18 A. In general, because of the benefits of optimizing storage dispatch against portfolio
19 requirements rather than an individual solar resource, the value of storage is likely to
20 be highest when it is managed independently of the solar resource it is connected to,
21 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.

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

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

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

1 with ongoing performance. For that reason, I recommend considering all storage
2 systems in a future proceeding.

3 LEVELIZATION PERIOD

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

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

11 **Q. Has PacifiCorp provided the information as directed?**

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

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

16 A. Yes. PacifiCorp is concerned about potentially locking in long-term fixed prices for
17 distributed solar resources based on forecasts that will likely be inaccurate over time.
18 PacifiCorp's IRP studies only evaluate its portfolio up to 20 years in the future, and
19 the 25 year term starting in 2018 includes six years beyond the end of the 2017 IRP,
20 and eight years beyond the end of the 2015 IRP, which still forms the basis for
21 avoided energy and generation capacity inputs. Reasonable fixed price terms are
22 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.

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

6 UTILITY SCALE ALTERNATIVE

7 **Q. Please describe the Commission’s direction regarding providing a utility scale
8 alternative.**

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

13 **Q. Please explain the utility scale alternative.**

14 A. PacifiCorp has prepared an avoided cost calculation by applying the current non-
15 standard QF avoided cost methodology to the indicative RVOS resources used to
16 illustrate the elements of the RVOS calculation. To reiterate, the indicative resource
17 represents a blend of solar generation profiles representing the Willamette Valley,
18 Southern Oregon, and Central Oregon, with an annual capacity factor of
19 approximately 21 percent. Because the non-standard avoided cost methodology is
20 based on the PacifiCorp’s most recently filed IRP, the available deferrable resources
21 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.

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

2 A. Non-standard avoided costs are calculated using the PDDRR methodology approved
3 by the Commission in 2016.³⁹ Under the PDDRR methodology, new resources are
4 assumed to displace capacity provided by market transactions during the resource
5 sufficiency period followed by a capacity-equivalent slice of the next major thermal
6 resource in the most recently filed IRP or IRP Update preferred portfolio. The GRID
7 model is used to identify the difference between the value of the resource being
8 added, and the value of the displaced market transactions and thermal resource being
9 removed. This accounts for a proposed resource's location, delivery pattern, and
10 capacity contribution and aligns with the company's long term resource plan by
11 incorporating the cost, timing, and characteristics of the preferred portfolio identified
12 by the IRP. This also captures the impact of individual and aggregate impact of
13 resource additions that are being considered. In addition, the current non-standard
14 avoided cost methodology includes a market price floor based on standard avoided
15 costs that is applicable during the resource sufficiency period. Because standard
16 avoided costs have generally been higher than those calculated using the PDDRR
17 methodology, the market price floor results in non-standard avoided costs that are
18 similar to standard avoided costs during the resource sufficiency period. To
19 demonstrate the difference, the PDDRR results shown do not include the market price
20 floor.

21 PacifiCorp has proposed changes to the non-standard QF methodology, which
22 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).

1 subsequent update.

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

5 A. As indicated above, PacifiCorp's standard avoided cost methodology is based on the
6 most recently acknowledged IRP, currently the 2015 IRP, whereas the non-standard
7 avoided cost methodology is based on the most recently filed IRP or IRP Update,
8 currently the 2017 IRP. As a result, the capacity contribution of the aggregate solar
9 resource using the hourly LOLP from the 2017 IRP is 46.5 percent versus
10 26.1 percent based on the hourly LOLP shape from the 2015 IRP as previously
11 described. In addition, the first deferrable thermal resource in the 2017 IRP preferred
12 portfolio is a 2029 simple cycle combustion turbine (SCCT) instead of the
13 2028 CCCT from the 2015 IRP preferred portfolio.

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

16 A. Yes. First, the non-standard avoided cost methodology incorporates the 2017 IRP
17 preferred portfolio and September 2017 market prices, as well the latest load forecast
18 and contracts. In contrast, the standard avoided cost methodology is still using the
19 2015 IRP preferred portfolio and market prices from March 2017, and does not
20 account for changes in load or contracts since the 2015 IRP was prepared. Second,
21 the non-standard avoided cost methodology accounts for resource specific
22 characteristics, including hourly generation profiles and delivery points, whereas
23 standard avoided costs do not make distinctions based on these characteristics.

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

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

5 A. Under the PDDRR methodology, the first utility resource that is eligible for deferral
6 is a 2029 SCCT from the 2017 IRP preferred portfolio. This resource has fixed costs
7 of \$139/kW-year starting in 2029, and increasing at inflation thereafter. Avoided
8 energy costs are based on the difference in system costs between two GRID model
9 studies. The first study contains PacifiCorp's current load and resource forecast,
10 including capacity additions identified in the preferred portfolio in PacifiCorp's most
11 recently filed IRP or IRP Update and all of the 2029 SCCT's remaining capacity.
12 The second study adds the proposed resource, in this case a 20 MW fixed solar
13 resource in Oregon, and removes market transactions followed by 8.8 MW of the
14 2029 SCCT, reflecting a capacity contribution equivalent amount after accounting for
15 solar degradation.

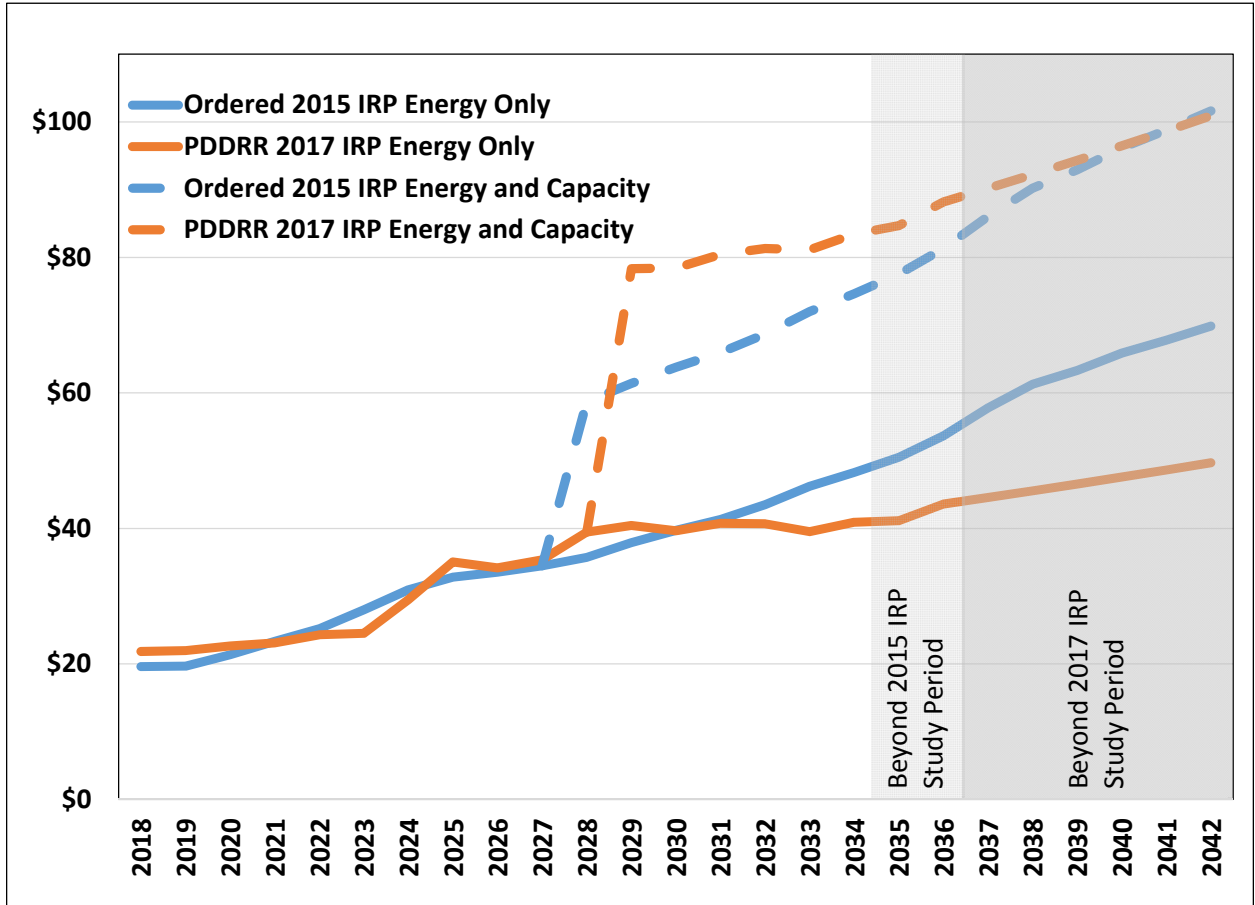
16 **Q. How do the avoided energy and generation capacity results vary under the**
17 **PDDRR methodology relative to the standard avoided cost methodology?**

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

⁴⁰ Order No. 17-357 at 6.

1 generation capacity costs are lower and begin one year later. In addition, the PDDRR
2 methodology reflects lost benefits from the displaced SCCT, including the value of
3 operating reserves, contributing to lower avoided costs during the deficiency period.
4 While the RVOS model has an input that similarly accounts for the expected revenues
5 associated with the generation capacity resource, for the ordered calculation this has
6 been left blank consistent with the current standard avoided cost methodology. While
7 the current standard avoided cost methodology accounts for the expected heat rate of
8 the proxy CCCT, it does not account for the dispatchability of that resource, including
9 its ability to provide reserves and ramp up or down, for instance in response to EIM
10 dispatch signals. When the higher solar capacity contribution values from the
11 2017 IRP are reflected in standard avoided cost following IRP acknowledgment,
12 standard avoided costs would likely approach or exceed non-standard avoided costs.

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



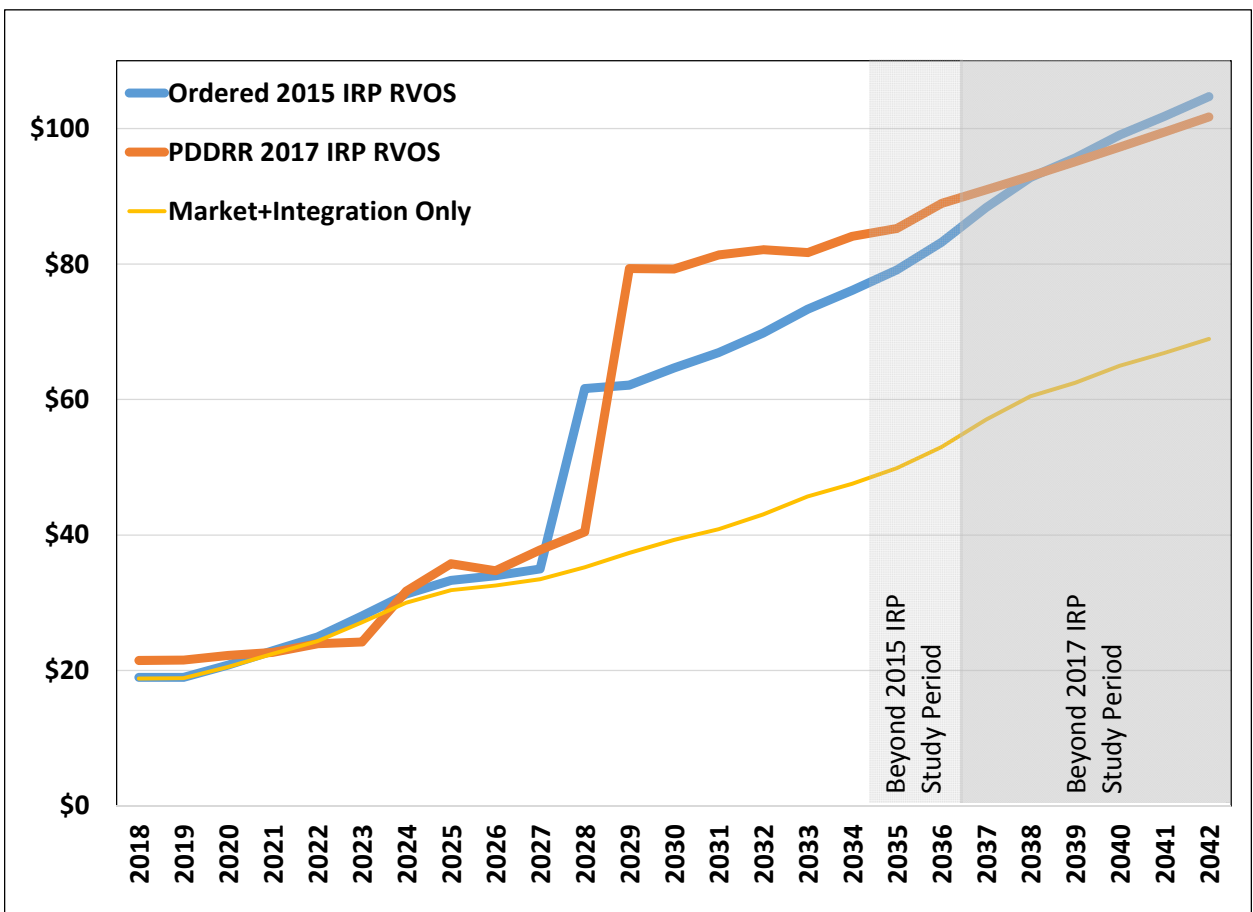
2 **Q. Are any other elements of the RVOS calculation impacted by the inclusion of the**
 3 **PDDRR results?**

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

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

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

7 **Figure 6: RVOS Results for the Indicative Fixed Solar Resource**



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

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

11 **Q. The Commission noted that it “will balance accuracy, transparency, and**
12 **accessibility to parties” as it determines the best RVOS methodology.⁴² What is**
13 **PacifiCorp’s position on this issue?**

14 A. First, I would note that the Commission has already determined that the PDDRR
15 methodology more accurately forecasts avoided costs for non-standard QFs where the
16 specific characteristics of the resources in question outweigh the administrative
17 burden that forms the basis for maintaining standard avoided costs for QFs. The
18 relevant issue is not whether using the PDDRR methodology and the GRID model to
19 inform inputs to the RVOS calculation results in lower or higher prices than using
20 standard costs; the relevant issue is whether the PDDRR methodology and the GRID
21 model produce a more accurate forecast of avoided costs, which they do. A
22 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.

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

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

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

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

1 **Q. Does this conclude your testimony?**

2 **A. Yes.**