

Docket No. UM 1910
Exhibit PAC/300
Witness: Daniel J. MacNeil

**BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON**

PACIFICORP

Reply Testimony of Daniel J. MacNeil

April 2018

REPLY TESTIMONY OF DANIEL J. MACNEIL
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1 **Q. Are you the same Daniel J. MacNeil who previously submitted testimony in this**
2 **proceeding on behalf of PacifiCorp d/b/a Pacific Power?**

3 A. Yes.

4 **PURPOSE AND SUMMARY OF TESTIMONY**

5 **Q. What is the purpose of your reply testimony?**

6 A. My reply testimony replies to opening testimony filed on March 16, 2018, by Public
7 Utility Commission of Oregon Staff (Staff) witness Ms. Brittany Andrus (Staff/100
8 and Staff/200), Citizen's Utility Board (CUB) witness William Gehrke (CUB/100-
9 102), Oregon Department of Energy (ODOE) witness Robert DelMar (ODOE/100),
10 Oregon Solar Energy Industries Association (OSEIA) witness R. Thomas Beach
11 (OSEIA/100-102), and Renewable Northwest (RNW) witness Michael O'Brien
12 (RNW/100).

13 **Q. Please summarize your reply testimony.**

14 A. My testimony provides support for five modifications to resource value of solar
15 (RVOS) values based on standard qualifying facility (QF) rates, in response to issues
16 identified by parties as well as corrections identified by PacifiCorp. PacifiCorp has
17 also reflected these changes in the RVOS values based on its partial displacement
18 differential revenue requirement (PDDRR) methodology, and has calculated an
19 additional RVOS sensitivity based on utility-scale solar costs. A summary of these
20 changes is shown in the table below. My testimony also explains why other
21 modifications to the RVOS calculation proposed by parties are inappropriate and
22 provides additional explanation of the relationships between RVOS applications,
23 inputs, and results.

Table 1: Summary of RVOS Results

\$/MWh Study Standard	RVOS Total Value		Delta	
	Real	Nominal	Real	Nominal
As filed (errata)	32.84	42.92		
+Corrected Admin Cost	33.07	43.21	0.22	0.29
+2018 Start for nominal pricing	33.07	41.03	0.00	(2.18)
+MPR separate from Energy	33.07	41.03	0.01	0.01
+Marginal Line Losses	33.28	41.29	0.21	0.26
+CO2 Price	36.99	45.89	3.71	4.60
Final	36.99	45.89		
PDDRR				
As filed (errata)	39.58	52.00		
Corrections + Updates	43.71	54.23	4.13	2.24
Utility-scale				
Starting 2021	34.22	42.46		
Starting 2030	30.39	37.71		

1 **Q. Are there any elements on which parties have not identified issues?**

2 A. Parties have not identified any issues related to the integration element or the
3 administration element beyond the correction discussed below. Therefore, I will not
4 address those elements here.

5 **RVOS APPLICATIONS AND KEY ASSUMPTIONS**

6 ***CORRECTIONS***

7 **Q. Have you identified any corrections to the RVOS template and inputs since your
8 original filing?**

9 A. Yes. PacifiCorp has identified two corrections since its initial filing. First, in
10 response to CUB data request 4, PacifiCorp identified a correction to administrative
11 costs, which reduced the real-levelized cost by 10 percent. Second, while preparing
12 response testimony, PacifiCorp identified that the reported nominal levelized values

1 reflected a 2020 start date. For comparability, this has been corrected to a 2018 start
2 date in the RVOS template and values reported herein. Depending on the timing of
3 full implementation of an RVOS rate, further adjustments to align with specific
4 applications will be necessary. After accounting for the corrections to administrative
5 costs and a 2018 start date, the RVOS value is \$32.84/MWh on a real-levelized basis
6 and \$40.75/MWh on a nominal levelized basis.

7 ***APPLICATIONS***

8 **Q. Are the values reported by the RVOS model universally applicable to solar**
9 **resources in Oregon?**

10 A. No. The reported RVOS values are only applicable to the extent they accurately
11 correspond with the impact of specific solar resources on PacifiCorp's system. The
12 key variables that impact whether the RVOS will accurately correspond to a specific
13 resource include the generation profile, interconnection voltage, transmission and
14 distribution location, and contract term.

15 **Q. What are the positions of the parties with respect to the solar generation profile?**

16 A. Staff is generally satisfied with the solar generation profile in PacifiCorp's RVOS
17 workbook.¹ ODOE suggests that variations in climate and technology should be
18 analyzed to assess the variation in solar generation profiles on RVOS values.²
19 OSEIA takes issue with the inclusion of solar profiles for Portland, Oregon in the
20 aggregate solar shape represented in PacifiCorp's RVOS workbook.³

¹ Staff/200, Andrus/5.

² ODOE/100, DelMar/5.

³ OSEIA/100, Beach/4.

1 **Q. How do you respond?**

2 A. First, PacifiCorp does in fact serve load within Portland, Oregon, contrary to the
3 statement made by OSEIA.⁴ Therefore, OSEIA's criticism regarding the inclusion of
4 solar profiles for Portland, Oregon is unfounded. Second, I agree with ODOE that
5 variations in climate and technology should be assessed as part of any application of
6 RVOS values.⁵ To address ODOE's concerns as well as Staff's concerns related to
7 capacity contribution values, when addressing the Generation Capacity element, I will
8 discuss RVOS results for several geographic locations and technologies. Third, the
9 solar generation profiles contained within PacifiCorp's RVOS model are a sample
10 intended to demonstrate the functioning of the model rather than a proposal for a
11 particular application. PacifiCorp understands that the use of the RVOS model for a
12 particular application would take place at a later stage in conjunction with
13 consideration of the application in question.

14 **Q. What are the expected applications for RVOS values?**

15 A. I understand that the RVOS values are expected to inform the calculation of bill credit
16 rates for community solar and also the extent of cost-shifting from net metering.

17 **Q. Do solar generation profiles vary significantly within and among these
18 applications?**

19 A. Yes. Community solar is likely to include both fixed and tracking solar technology,
20 with relatively optimized location-specific characteristics, including tilt and shading.
21 Rooftop solar is likely to be less optimized, with tilt determined by available
22 structures and shading based on vegetation and neighboring buildings. In addition,

⁴ OSEIA/100, Beach/4.

⁵ ODOE/100, DelMar/5.

1 solar resources used for net metering may be distinguished between volumes used on-
2 site, and volumes exported to the grid. To the extent the RVOS methodology is used
3 to value volumes exported to the grid, a generation profile consistent with the
4 exported volume should be used, rather than the entire solar resource output.

5 **Q. Are there any other issues that may impact application-specific RVOS**
6 **calculations?**

7 A. Yes. Interconnection voltage is another issue, and parties do not appear to have
8 articulated any positions on the interconnection voltage inputs to the RVOS model.
9 The RVOS model currently contains inputs reflecting a blend of solar resources,
10 several of which are assumed to be used behind-the-meter at the secondary level, and
11 one of which is assumed to be exported across the transmission system. These are
12 arbitrary designations intended to illustrate the flexibility of the RVOS methodology
13 rather than a specific program.

14 **Q. How do interconnection voltage assumptions in the RVOS methodology relate to**
15 **net metering?**

16 A. To the extent a residential customer's entire solar output is being valued, that portion
17 of the output that is used behind-the-meter would be credited with avoiding secondary
18 losses. The portion of the output that is exported would be credited with avoiding
19 primary losses.

20 **Q. How do interconnection voltage assumptions in the RVOS methodology relate to**
21 **community solar?**

22 A. It is unclear at this time as community solar resources could potentially be
23 interconnected at transmission, primary, or secondary voltage. As with net metering,

1 the expected level of exports would determine the level of avoided losses. For
2 instance, community solar resources could potentially be located behind-the-meter,
3 with a single customer hosting a solar resource and sharing some or all of the output
4 with other subscribers.

5 **Q. What are the positions of the parties with regard to transmission and**
6 **distribution location?**

7 A. Staff and OSEIA support the use of a system-wide average for avoided transmission
8 and distribution infrastructure costs in this proceeding.⁶ As OSEIA notes, there are
9 significant opportunities to target distributed energy resources to locations where they
10 provide the greatest value.⁷ This also means that many locations provide little or no
11 value. Paying extra for targeted resources and system average costs for everything
12 else results in an overpayment. This issue is discussed in more detail in the testimony
13 of Mr. Putnam (PAC/400).

14 **Q. Do parties take any positions with regard to contract length?**

15 A. It does not appear so. PacifiCorp populated the E3 workbooks for 25 years beginning
16 in 2018, which is consistent with Commission's directive in Order No. 17-357 and
17 the Commission's statement that the application of RVOS to community solar (or any
18 other application) has not yet been determined.⁸ Contract length is a critical input for
19 any application of the RVOS methodology.

⁶ Staff/100, Andrus/29; OSEIA/100, Beach/13.

⁷ OSEIA/100, Beach/20–21.

⁸ See Order No. 17-357 at 16.

1 ***LEVELIZATION AND INFLATION***

2 **Q. What issues do parties raise related to levelization and inflation?**

3 A. Staff raises concerns that PacifiCorp reported nominal-levelized results rather than
4 real-levelized results and suggests that both values should be reported.⁹ CUB
5 proposes that the inflation rate be set at two percent consistent with Federal Reserve
6 Policy.¹⁰

7 **Q. Does PacifiCorp have concerns with reporting both real-levelized and nominal-**
8 **levelized results?**

9 A. No. Real and nominal values are equivalent, but represent different units. Real-
10 levelized and nominal-levelized results can be readily produced from the E3 model,
11 and while real-levelized results may make for easier comparisons between utilities,
12 nominal-levelized results better represent the payment stream a solar resource would
13 receive in a single value. In the current E3 model, real values represent 2018 U.S.
14 dollars in every year, while nominal values represent current year dollars—2018 U.S.
15 dollars in 2018, 2019 U.S. dollars in 2019, 2020 U.S. dollars in 2020, and so on.
16 Because of inflation, 2019 dollars have less value than 2018 dollars, so more of them
17 are required to produce equivalent value. The impact of inflation also compounds
18 each year. Any future payments would necessarily be made in then-current-year
19 dollars, so a nominal levelized value is a convenient way to express these future
20 payments in a single number.

21 **Q. What does a nominal-levelized RVOS value represent?**

22 A. The nominal-levelized RVOS value is a single number, which if paid over the

⁹ Staff/100, Andrus/53–55.

¹⁰ CUB/100, Gehrke/5–7.

1 levelization period, would result in the same net present value as the nominal stream
2 of annual values. In the current RVOS results, the early years have annual values that
3 are lower than the nominal-levelized value for the 25-year term. If the nominal-
4 levelized value was paid to the RVOS resource during those years, the difference
5 between the annual and levelized values would essentially be a loan or pre-payment,
6 calculated at a 6.66 percent interest rate (the nominal discount rate and PacifiCorp's
7 weighted average cost of capital from the 2015 Integrated Resource Plan (IRP)
8 currently reflected in standard QF avoided cost rates). This loan is repaid in the later
9 years of the term when the annual values exceed the levelized value, so the value is
10 expected to be equivalent by the end of the contract, so long as deliveries are uniform
11 over the contract period.

12 **Q. Is there an alternative levelized payment stream based on real-levelized RVOS**
13 **values?**

14 A. Yes. Using the real-levelized RVOS value for 2018 and escalating each year's value
15 at inflation produces the same net present value as the single nominal levelized value
16 described above, so long as deliveries are uniform over the contract period.

17 **Q. Are there any additional consideration for levelized payments?**

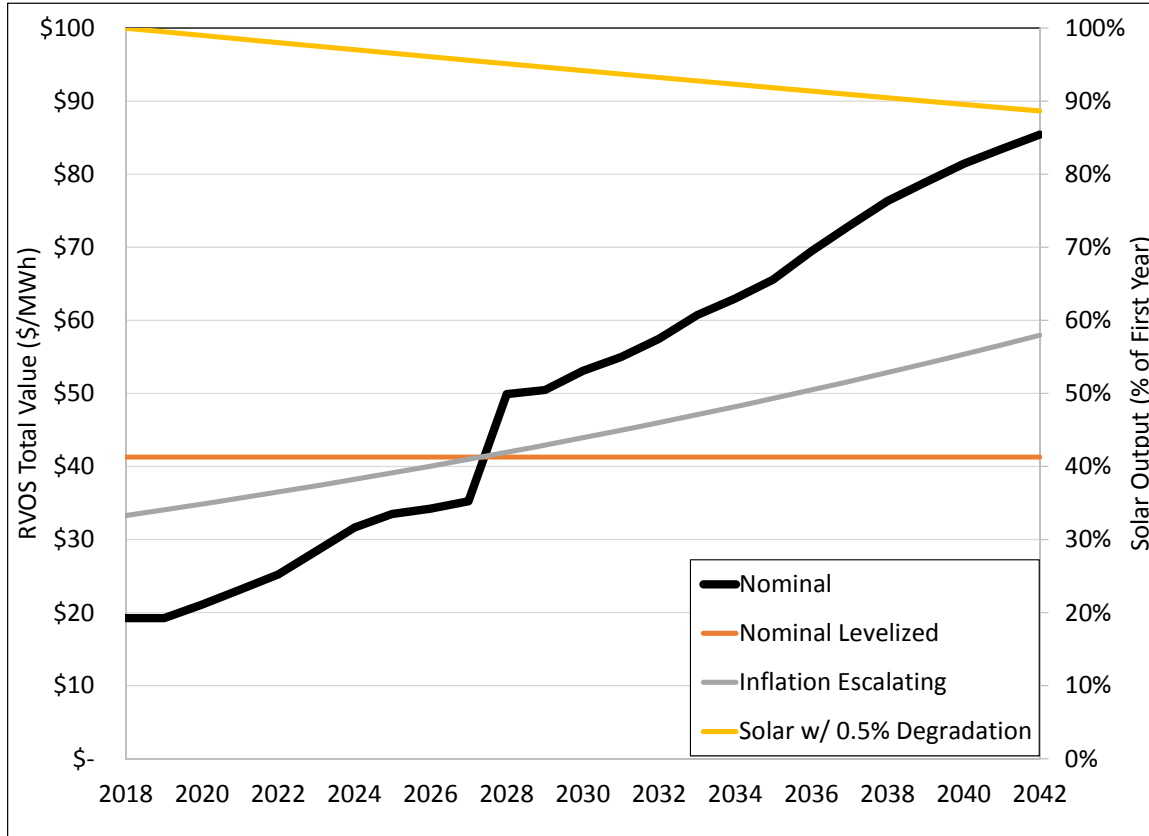
18 A. Yes. First, the RVOS workbook assumes solar resource output is constant over the
19 25-year study period. Solar resources degrade over time, and are expected to have
20 declining output as time goes on, resulting in less value in future years than indicated
21 in the current template. Second, solar generation output is subject to customer
22 maintenance and repair, and therefore some resources may cease generating before
23 the end of the term, resulting in no value from that point forward. Any program with

1 levelized payments will need to include performance requirements through the end of
2 the levelized term to prevent cost-shifting and protect other customers.

3 **Q. Can you provide an illustration of how annual and levelized RVOS values**
4 **compare?**

5 A. Yes. Figure 1 shows the annual stream of RVOS values with payment streams that
6 replicate the value of that annual stream over a 25-year contract. The nominal
7 levelized payment stream has the same value over the entire term, \$41.29/MWh. The
8 inflation escalating payment stream starts at the real-levelized value of \$33.28/MWh
9 in 2018, and escalates at inflation. Figure 1 also shows the impact of solar
10 degradation of 0.5 percent of the previous year's generation. This degradation would
11 result in a six percent reduction in real-levelized value, and, if not accounted for in a
12 levelized payment stream, would result in an overpayment of one to two percent over
13 a 25-year term. Program attrition would similarly result in higher than anticipated
14 non-participating customer costs over the life of a program as reduced resource output
15 and benefits at the end of the term would be inadequate to compensate for front-end
16 levelized payments.

Figure 1: RVOS Payment Streams and Degradation



1 **Q. Is CUB’s proposed change to the inflation rate reasonable?**

2 A. No. CUB is incorrect in stating that PacifiCorp’s standard company inflation
 3 estimate is two percent.¹¹ PacifiCorp’s standard inflation estimate is a curve with
 4 annual values calculated as a straight average of forecasts for the Gross Domestic
 5 Product (GDP) inflator and the Consumer Price Index (CPI). This standard inflation
 6 curve is used in the IRP, and is a core assumption. Changes to the inflation rate used
 7 in the IRP would change the outcome of the IRP, including potentially the
 8 composition of the preferred portfolio.

¹¹ CUB/100, Gehrke/7.

1 **UPDATES TO RVOS MODEL**

2 **Q. What positions do parties take with regard to updates to the RVOS model?**

3 A. Staff suggests that, for administrative efficiency, updates for energy value should
4 occur in conjunction with annual standard QF avoided cost updates, while also
5 suggesting that forward prices should reflect the most recent curve available, rather
6 than the curve in standard QF avoided cost updates.¹² Staff also suggests that
7 generation capacity, integration and environmental compliance should be updated
8 post-IRP acknowledgment.¹³ Finally, Staff suggests that updated values would only
9 be incorporated in new agreements.¹⁴ CUB suggests that annual updates to the RVOS
10 model would be appropriate.¹⁵ RNW suggests that the RVOS should be updated to
11 reflect the latest acknowledged IRP.¹⁶

12 **Q. Do you have concerns with Staff's proposals for updating RVOS energy values?**

13 A. Yes. Staff's proposals for updating RVOS energy values appear to be contradictory,
14 relying on either the current approved standard QF values or the most recent forward
15 price curve. PacifiCorp is not opposed to calculating avoided costs based on its most
16 recent official forward price curve (OFPC), and already prepares avoided costs using
17 the most recent forward prices for non-standard QFs under its PDDRR methodology.
18 However, the current avoided cost methodology for non-standard QFs includes a
19 market price floor that overrides the most recent results when those results are lower
20 than the approved standard QF values. Staff has argued in support of the market price

¹² Staff/100, Andrus/11–12, 58–59

¹³ Staff/100, Andrus/58–59.

¹⁴ Staff/100, Andrus/60.

¹⁵ CUB/100, Gehrke/3–4.

¹⁶ RNW/100, O'Brien/4.

1 floor, and in favor of using standard QF values for non-standard QF pricing, both of
2 which result in the application of less up-to-date forward prices.¹⁷ It is unclear why
3 Staff believes the most recent forward prices are appropriate for RVOS applications
4 of up to three MW, but not for non-standard QF resources of up to 80 MW. For
5 administrative efficiency, and to avoid having different values for comparable
6 resources under different programs, PacifiCorp supports using consistent assumptions
7 and, to the extent feasible, methodologies, for RVOS, standard QF pricing, and non-
8 standard QF pricing.

9 **Q. Do you have concerns with Staff's proposals for updating RVOS generation**
10 **capacity values?**

11 A. Yes. Contrary to Staff's proposal to keep generation capacity assumptions static
12 between IRP acknowledgment cycles, generation capacity needs are impacted by
13 long-term contracts executed since an IRP was prepared. The length of time between
14 IRP preparation and acknowledgment and between IRPs may result in significant
15 changes that would necessitate more frequent updates. Identifying executed contracts
16 and applying the capacity contribution values from the IRP should be straightforward,
17 so updating generation capacity needs is reasonable, and should be part of other
18 scheduled updates.

19 **Q. Do you have any concerns with Staff's proposals to apply updated RVOS values**
20 **only to new agreements?**

21 A. Yes. Since contract length and other details pertaining to the application of RVOS to
22 particular programs have yet to be determined, it is premature to decide whether or

¹⁷ See, *In the Matter of Public Utility Commission of Oregon, Investigation to Examine PacifiCorp, dba Pacific Power's Non-Standard Avoided Cost Pricing*, Staff Opening Brief (Sept 18, 2017).

1 how updated values would impact previous agreements.

2 **Q. Do you have any comments on RNW’s proposal to update the RVOS to reflect**
3 **the recently acknowledged 2017 IRP?**

4 A. Yes. The current RVOS methodology is tied to PacifiCorp’s currently approved
5 standard QF values. While the company is preparing updated standard QF pricing to
6 reflect the Commission’s vote to acknowledge the 2017 IRP, the updated prices were
7 not available at the time RVOS testimony was due and have not yet been approved.
8 PacifiCorp intends to provide updated RVOS values incorporating the 2017 IRP
9 when they are available.

10 **ENERGY**

11 **Q. What issues do parties raise related to the energy element in PacifiCorp’s RVOS**
12 **filing?**

13 A. Parties raise two issues related to the RVOS energy element. First, Staff and RNW
14 question the use of Energy Imbalance Market (EIM) pricing in the RVOS model,
15 while OSEIA supports the use of EIM pricing, but proposes modifications to the
16 calculation. Second, Staff proposes modifications to the manner in which hydro
17 conditions are incorporated in the energy element. I respond to parties’ issues in the
18 following sections.

19 ***HOURLY PRICE SHAPING***

20 **Q. Please summarize the objections Staff and RNW raise with using EIM pricing in**
21 **the RVOS model.**

22 A. Staff states that it does not believe PacifiCorp’s use of EIM settlement prices provides
23 an appropriate reference point for hourly shaping of prices, noting that “while

1 PacifiCorp conducts many transactions in the EIM, the majority of its wholesale
2 transactions are not in that market.”¹⁸ Staff concludes that it “is not opposed to
3 including EIM values as part of the shaping algorithm, but Staff does not support
4 using EIM settlement values as the sole shaping factor.”¹⁹ RNW questions “how
5 informative pricing data from a 5-15 minute spot energy market may be in creating
6 the 12x24 hourly price shape that could be used for the valuation of a long-term firm
7 resource.”²⁰

8 **Q. Why would it be problematic to use PacifiCorp’s short-term wholesale**
9 **transactions to indicate hourly prices?**

10 A. These short-term wholesale transactions do not provide useful reference points for
11 hourly pricing. The vast majority of PacifiCorp’s transactions span large blocks of
12 hours. For example, a day-ahead heavy-load hour transaction spans 16 hours at a
13 single price. Such block transactions do not provide hourly price information. The
14 limited number of hourly transactions that did occur averaged just 64 MW of
15 purchases and 105 MW of sales in 2017. This represents just four percent of
16 PacifiCorp’s total short-term firm purchases in 2017 and seven percent of its short-
17 term firm sales.

18 **Q. Are EIM values the “sole shaping factor” for the energy prices used in the**
19 **RVOS model as Staff suggests?**

20 A. No. The energy prices in the RVOS model are first a function of the monthly forward
21 prices in the company’s OFPC. EIM values are only used to shape the monthly prices

¹⁸ Staff/100, Andrus/9.

¹⁹ Staff/100, Andrus/9.

²⁰ RNW/100, O’Brien/7.

1 over the 24 hours in each day.

2 **Q. Does the 12x24 hourly shapes in the current RVOS model fully represent the**
3 **energy value of solar resources?**

4 A. No. As parties note, EIM settlements cover five and 15 minute intervals. These sub-
5 hourly values would also impact the value of variable resources such as solar. Solar
6 resources ramp up and down every day, and there is a significant correlation between
7 the output of an individual resource and of solar resources across the region because
8 both are reliant upon the position of the sun. As a result, when solar resources are
9 ramping up in the morning or down in the evening, it is likely that other solar
10 resources are also ramping in the same direction. Prices tend to decline as available
11 resources increase—this is the same principle underlying the market price response
12 element. As a result, the average energy value of solar will tend to be overstated by
13 an hourly energy price, as the portion of an hour with the greatest solar output will
14 tend to have the lowest price. The impact of sub-hourly solar output changes has not
15 been incorporated in the proposed hourly price shaping based on EIM prices because
16 the current method reflects simple averages of the hourly values.

17 **Q. Are RVOS resources considered long-term firm resources as suggested by**
18 **RNW?**

19 A. No. Solar resources are contingent upon both solar and mechanical capability, so
20 they are not firm. PacifiCorp compensates for uncertainty and variations in the output
21 of solar resources, and an estimate of this cost is included in the solar integration cost.
22 PacifiCorp is also obligated to carry contingency reserves for solar generation in
23 accordance with North American Electric Reliability Corporation regional reliability

1 standards. PacifiCorp is not obligated to carry contingency reserves for market
2 purchases, and, consistent with the current approved standard QF avoided cost
3 methodology, no adjustment is made to forward market prices to account for this cost
4 during the sufficiency period.

5 **Q. Does Staff or RNW propose an alternative to PacifiCorp's proposal to shape**
6 **hourly prices using EIM data?**

7 A. No.

8 **Q. What is OSEIA's proposal for hourly price shaping?**

9 A. OSEIA supports the use of EIM data to set hourly price shapes, and proposes that it
10 be adopted by all three utilities, but modifies the methodology to include EIM pricing
11 data as reported.²¹ PacifiCorp's proposal capped the EIM pricing results at -
12 \$50/MWh and \$200/MWh because extreme prices are generally a result of
13 unexpected conditions, which may include significant deviations from forecasted
14 load, wind, or solar. Such deviations are largely random, so the presence of extreme
15 values is generally a chance occurrence, rather than a characteristic of a given hour.

16 **Q. What can cause outlier pricing intervals?**

17 A. EIM is a market for *imbalance*, so outlier pricing occurs when the actual load and
18 resource balance deviates significantly from forecasted levels. A spike in load or
19 drop of variable generation could both result in elevated prices in a particular interval.

20 **Q. Can you provide an example illustrating how extreme values in the historical**
21 **data distort the results?**

22 A. Yes. The PACW EIM prices for hour ending 13 in June 2017 include one 15 minute

²¹ OSEIA/100, Beach/5.

1 interval with prices of \$1000/MWh. Excluding that single 15 minute interval, the
2 average price for that period is \$19/MWh, implying a scalar value of 1.49. However,
3 when that single interval is included, the average price jumps to \$27/MWh, implying
4 a scalar value of 2.08. Under PacifiCorp's proposal, hours ending 12 and 14 in June
5 have scalar values of 1.14 and 1.18, significantly lower than the capped value of 1.55
6 for hour-ending 13. With that in mind, the higher scalar value for hour-ending 13 is
7 more akin to a random outlier interval rather than meaningful information about that
8 hour. It is also worth noting that the cap only dampens the impact in hour-ending 13,
9 making it somewhat less extreme, while not completely eliminating it, as evidenced
10 by the significant variation relative to the hours before and after.

11 **Q. Do EIM price caps reduce the average energy price in the RVOS model?**

12 A. No. The average energy price in the RVOS model remains tied to the company's
13 forward price curve. The EIM hourly price shaping only allocates the value among
14 the hours in the day. While prices vary in certain hours as a result of the hourly price
15 shaping, the total value remains equal to the forward market prices, regardless of the
16 shaping methodology.

17 **Q. What do you recommend with regard to hourly energy price shaping?**

18 A. PacifiCorp continues to recommend using hourly energy prices shaped based on EIM
19 prices, with caps applied to reduce the impact of outlier results.

20 ***HYDRO CONDITIONS***

21 **Q. Please summarize the objections Staff raises with regard to PacifiCorp's**
22 **adjustment for hydro conditions.**

23 A. Staff believes PacifiCorp "came close" with its approach to the adjustment for hydro

1 conditions.²² Staff's recommends selecting a random sample of hydro years, creating
2 a forward price curve for each year in the sample, and performing statistical analysis
3 on a set of forward price curves.²³ Staff is also concerned that PacifiCorp uses
4 historical generation, rather than current generation under historical flows.²⁴

5 **Q. For which hydro years does PacifiCorp have forward price curves?**

6 A. PacifiCorp has forward price curves based on a normal hydro year, a wet hydro year
7 (1999), and a dry hydro year (1992).

8 **Q. How did PacifiCorp incorporate those hydro years in its initial RVOS filing?**

9 A. PacifiCorp blended the three curves based on the wet and dry conditions in a
10 historical sample of hydro data from 1990 to 2015. As discussed in my direct
11 testimony, wet conditions were given a 20 percent weighting, dry conditions were
12 given a 33 percent weighting, and normal conditions were given a 47 percent
13 weighting. The single blended curve was used in the RVOS workbook.

14 **Q. Has PacifiCorp prepared analysis to address Staff's concerns?**

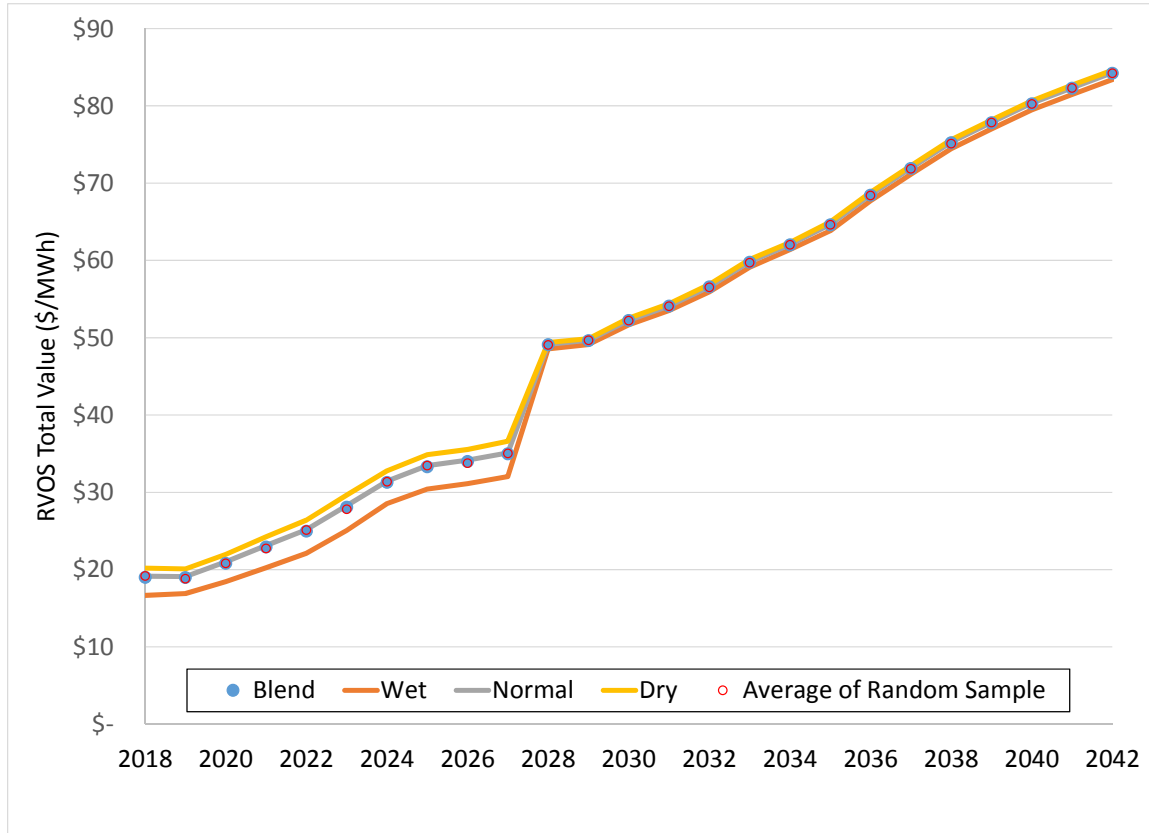
15 A. Yes. PacifiCorp prepared three versions of its RVOS template, one for each hydro
16 condition. Next, PacifiCorp created one hundred scenarios with random hydro
17 conditions (wet/dry/normal) for each year of the 25-year RVOS study period. The
18 probability of each condition in each year was based on the same weightings
19 described above, 20 percent wet, 33 percent dry, and 47 percent normal. The results
20 are shown in the figure below.

²² Staff/100, Andrus/16.

²³ Staff/100, Andrus/16.

²⁴ Staff/100, Andrus/15.

Figure 2: RVOS Total Value by Hydro Condition



1 **Q. What does the analysis show?**

2 A. Using the random sampling technique described above produces a comparable result
3 to that in PacifiCorp's filing—a minor reduction in the forward price curve.

4 **Q. Is it reasonable that the RVOS model does not show a greater impact?**

5 A. Yes. As shown in Figure 2, the variation between wet and dry years is relatively
6 small. This is partly because PacifiCorp's market prices include the California-
7 Oregon Border and Palo Verde markets, which are less affected by hydro conditions.
8 In addition, once RVOS energy prices switch to a gas resource in the deficiency
9 period, the variation becomes minimal, reflecting only minor seasonal variations.

10 While the impact on the RVOS model extends beyond the energy value to the values

1 for avoided line losses and hedging, both of those values use a percentage adjustment,
2 so the magnitude of the change does not impact the result. As a result, using a
3 weighted average price curve is equivalent to using a sample of hydro conditions.

4 **Q. Do you have any other comments on the impact of hydro conditions?**

5 A. Yes. Because PacifiCorp is using a forward price curve that accounts for the risk
6 between the present and the time of delivery, it will already account for some of the
7 known risk associated with variations in hydro conditions.

8 **Q. What do you recommend with regard to the adjustment for hydro conditions?**

9 A. Given the complexity of the analysis, minimal impact on PacifiCorp's RVOS
10 calculation, and potential overlap with value already represented in the forward
11 market price, I question the need for a hydro adjustment in the RVOS methodology.
12 However, PacifiCorp's initial filing made an appropriate hydro adjustment consistent
13 with the Commission's order and that adjustment is continues to be reflected in its
14 updated RVOS model.

15 MARKET PRICE RESPONSE

16 **Q. What issues do parties raise related to the market price response element?**

17 A. Staff objects to PacifiCorp's calculation of market price response (MPR) outside the
18 RVOS model, recommends that it be reported separately from the energy element,
19 and suggests that PacifiCorp's "value reflects only one year and has not been
20 levelized."²⁵ Staff agrees with PacifiCorp that the interaction between avoided
21 energy costs and MPR has the potential to double count benefits associated with
22 solar, but recommends PacifiCorp not include it unless it can be calculated with more

²⁵ Staff/100, Andrus/53-55.

1 accuracy.²⁶ OSEIA mistakenly suggests that PacifiCorp used a zero MPR, and
2 proposes using PGE's value of 3.8 percent of avoided energy value as an
3 alternative.²⁷ RNW notes that the MPR included in the PDDRR results is zero.

4 **Q. Why did PacifiCorp calculate a MPR value outside the RVOS model?**

5 A. The RVOS model uses three basic inputs to determine MPR value over the 25-year
6 study period:

- 7
- 8 • Start year solar capacity (MW)
 - 9 • Effect on price of market energy during solar hours (\$/MWh) (\$2018)
 - 9 • Net annual market purchases (sales) during solar hours (MWh)

10 Each of these inputs also has an associated escalation rate that is assumed to be
11 uniform over the study period. PacifiCorp's values for net market purchases and the
12 effect on price of market purchases are more granular than these single values. For
13 instance, PacifiCorp's net market purchase position has periodic step changes as a
14 result of portfolio changes including coal retirements and contract expiration.
15 PacifiCorp's net market position is also comprised of transactions in multiple markets
16 and the blend varies both across the year and over time. PacifiCorp's representation
17 of the MPR for each of these markets is not a single value, but a forecast that varies
18 over time. As a result, PacifiCorp's circumstances are not readily represented by the
19 single value inputs for MPR in the RVOS model.

20 **Q. Is Staff correct in its conclusion that PacifiCorp's MPR "value reflects only one**
21 **year"?**²⁸

22 A. No. PacifiCorp calculated a market price response for every year of the study period

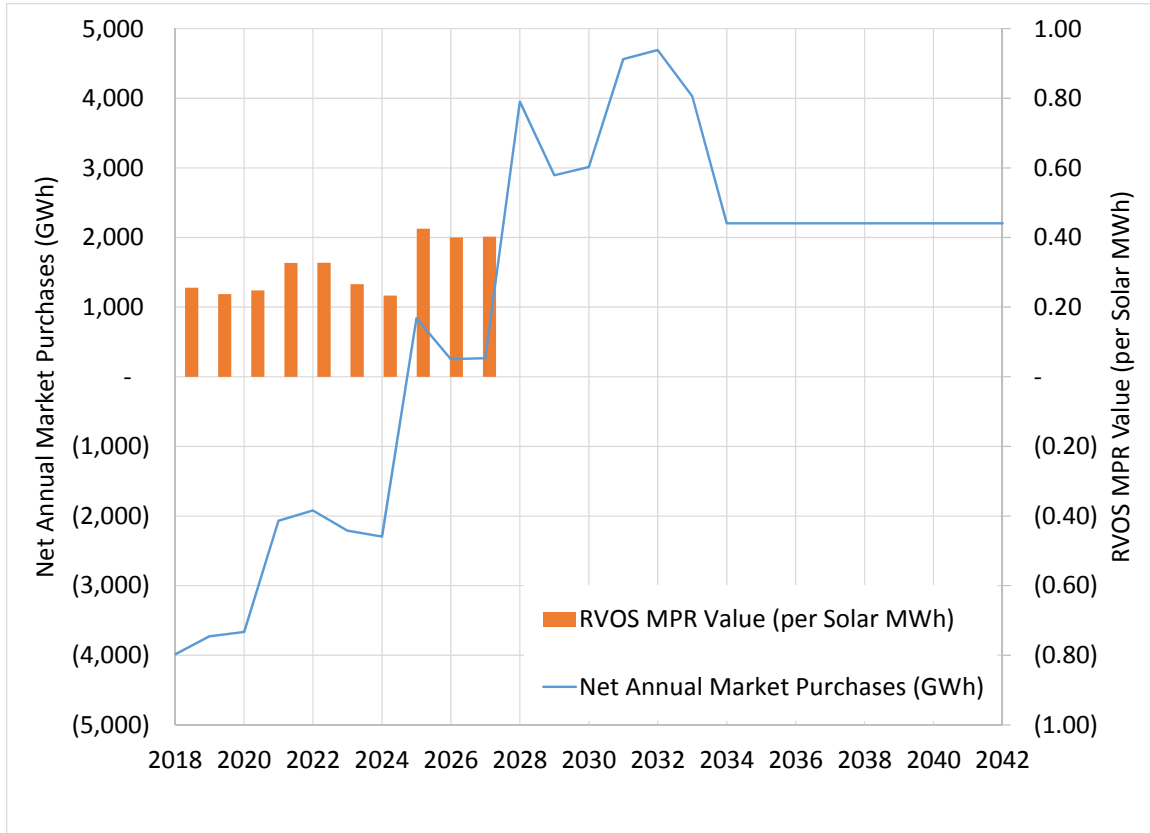
²⁶ Staff/100, Andrus/13-14, 43.

²⁷ OSEIA/100, Beach/29-30.

²⁸ Staff/100, Andrus/53-55.

1 for each of the three major markets that comprise the avoided energy costs in standard
2 QF rates and the RVOS model. The MPR is not uniform across the year, but the
3 small size of the change can be lost in noise in the results. Instead of using the
4 monthly results directly, PacifiCorp calculated a single “normal” monthly shape from
5 across the study period—this is used to spread the annual MPR to monthly heavy-
6 load hour and light-load hour intervals. The annual MPR value per MWh of solar
7 output is shown in Figure 3 below and was provided in the workpapers supporting
8 PacifiCorp’s initial filing. The value drops to zero in the deficiency period in 2028
9 under the standard methodology because the solar resource output is negated by the
10 lost output of the avoided generation capacity resource. Also shown in in Figure 3
11 below, PacifiCorp starts out with a long market position (net sales) and transitions to
12 a short position over time. While it is not shown in the annual data, throughout the
13 study period PacifiCorp is a net purchaser during summer periods when solar
14 generation is highest, resulting in a net benefit from the MPR during years when
15 PacifiCorp is a net seller.

Figure 3: Market Price Response RVOS Value and Market Position



1 **Q. Can you report PacifiCorp’s MPR results separately from the effect of MPR on**
2 **avoided energy cost?**

3 A. Yes. The MPR values shown in figure 3 above can be included in the RVOS model
4 directly, rather than via the energy input. Inputting these final values bypasses the
5 MPR inputs in the RVOS model described above due to the complexities discussed
6 above. The result is a real levelized RVOS value of \$0.15/MWh for the MPR
7 element, but the net increase is close to zero since comparable values were previously
8 included in the energy element. The net impact of minor changes in monthly shaping,
9 losses, and hedging value is an increase to the total RVOS value of less than
10 \$0.01/MWh on a real-levelized basis.

1 **Q. Is OSEIA’s proposal to use PGE’s MPR value of 3.8 percent of avoided energy**
2 **costs appropriate for PacifiCorp?**

3 A. No. The value from market price response is directly tied to a utility’s long or short
4 market position and the markets in which in transacts. As discussed above,
5 PacifiCorp’s market position varies over the course of the year and across multiple
6 widely distributed markets. Values calculated for PGE are not an accurate
7 representation of the value to PacifiCorp.

8 **Q. While Staff agrees that solar additions will result in declining avoided energy**
9 **costs, it suggests PacifiCorp should not adjust avoided energy costs unless it can**
10 **be calculated with more accuracy.²⁹ How do you respond?**

11 A. PacifiCorp’s avoided energy value only includes the MPR impact based on half of the
12 Oregon distributed solar resource additions between 2018 and 2036 in the 2017
13 IRP—a total of 150 MW. At this time, PacifiCorp has not made a further adjustment
14 for executed or potential PacifiCorp solar contracts or other WECC solar capacity
15 additions.

16 **GENERATION CAPACITY**

17 **Q. What issues do parties raise related to the generation capacity element?**

18 A. Parties raise issues with the generation capacity element that generally fall into two
19 categories. First, parties propose changes to sufficiency period capacity value and
20 timing. Second, parties raise concerns related to the calculation of capacity
21 contribution values. I respond to both issues in the following sections.

²⁹ Staff/200, Andrus/13–14, 43.

1 ***CAPACITY DURING THE SUFFICIENCY PERIOD***

2 **Q. What issues do parties raise related to sufficiency period capacity value and**
3 **timing?**

4 A. Staff and RNW propose that the RVOS resource sufficiency period be updated to
5 reflect the recently acknowledged 2017 IRP.³⁰ CUB proposes that the sufficiency
6 period be removed from the RVOS calculation, to reflect the capacity value solar
7 projects provide from their first year of operation.³¹ OSEIA supports including
8 incremental capacity payments during the sufficiency period based on thermal
9 operations and maintenance (O&M) expenses and proposes accelerating the
10 deficiency period by four years.³²

11 **Q. Has the Commission provided guidance on the determination of capacity value**
12 **and deficiency date?**

13 A. Yes. In Order No. 17-357, the Commission ordered that: “all utilities will provide
14 capacity value and timing (deficiency date) in line with their current approved
15 standard non-renewable QF avoided cost capacity value.”³³

16 **Q. Has PacifiCorp complied with the Commission’s directive?**

17 A. Yes. PacifiCorp’s currently approved standard non-renewable QF avoided cost
18 capacity values are drawn from its 2015 IRP. While the company is preparing
19 updated standard QF pricing to reflect acknowledgment of the 2017 IRP, the updated
20 prices were not available at the time RVOS testimony was due and have not yet been

³⁰ Staff/100, Andrus/20; RNW/100, O’Brien/10.

³¹ CUB/100, Gehrke/5.

³² OSEIA/100, Beach/10–11.

³³ Order No. 17-357 at 6.

1 approved. PacifiCorp intends to provide updated RVOS values incorporating the
2 2017 IRP when they are available.

3 **Q. Does the currently approved standard non-renewable QF pricing include**
4 **capacity value during the entirety of the sufficiency period?**

5 A. Yes. In Order No. 05-584, the Commission ordered that QF avoided costs be based
6 on monthly on- and off-peak forward market prices, as this “embeds the value of
7 incremental QF capacity in the total market-based avoided cost rate.”³⁴ The
8 Commission recently upheld this position in Order No. 16-174.³⁵

9 **Q. In light of the Commission orders on the capacity value of market purchases,**
10 **does the RVOS model reflect capacity value during the deficiency period?**

11 A. Yes. Because the current RVOS energy value during the deficiency period is based
12 on forward market prices, it includes capacity value. As a result, CUB’s proposal to
13 eliminate the sufficiency period to account for capacity value from the first year of
14 operation is unfounded.

15 **Q. Are incremental payments for thermal resource O&M expenses appropriate**
16 **during the sufficiency period?**

17 A. No. Since energy value during the sufficiency period is based on market prices rather
18 than PacifiCorp’s marginal resource dispatch costs, it is inappropriate to include
19 additional O&M costs. OSEIA alludes to this fact by highlighting that PacifiCorp
20 acquires short-term capacity in the form of market transactions.³⁶

³⁴ See Order No. 05-584 at 27–28.

³⁵ See Order No. 16-174 at 2.

³⁶ OSEIA/100, Beach/10.

1 **Q. What basis does OSEIA provide for advancing the resource deficiency year?**

2 A. OSEIA suggests that the “smaller capacity increments and shorter lead times” of
3 RVOS resources will allow deployment to more closely match future load growth and
4 capacity needs.³⁷ OSEIA provides an example and concludes that RVOS resources
5 are undervalued in the absence of additional capacity payments before the year of the
6 next major resource.³⁸

7 **Q. Is OSEIA’s proposal to advance the resource deficiency year likely to result in**
8 **more accurate avoided costs?**

9 A. No. Looking at PacifiCorp’s 2017 IRP preferred portfolio, the first major non-
10 renewable resource is a 200 MW simple cycle combustion turbine (SCCT) added in
11 2029. By OSEIA’s logic, this “lumpy” resource is likely providing much more
12 capacity than PacifiCorp needs in its first year of operation. If not all of the resource
13 is needed in the first year of operation, a portion of the capacity added in that year
14 could otherwise have come from lower-cost alternatives (i.e. market). In the 2017
15 IRP preferred portfolio, the capacity from market transactions in 2029 is equal to the
16 maximum available, indicating that the entire SCCT capacity is needed. Furthermore,
17 even if a portion of the SCCT capacity was not needed, that would not imply that
18 customers should be obligated to pay for capacity sooner, it would imply that
19 customer’s obligation to pay for at least a portion of that resource could be deferred to
20 a later date.

³⁷ OSEIA/100, Beach/6–8.

³⁸ OSEIA/100, Beach/7–8.

1 **Q. Does the company have a generation capacity deferral mechanism that accounts**
2 **for the relationship between a resource’s capacity and the capacity deficiency**
3 **year?**

4 A. Yes. The PDDRR methodology, which has been approved for pricing non-standard
5 Oregon QFs, assumes that a resource defers a specific increment of a resource
6 addition from PacifiCorp’s IRP preferred portfolio. Once an IRP resource addition is
7 fully displaced by QFs, successive QFs displace later resource additions. The IRP
8 resource is reduced in size by exactly the capacity contribution of the QF, even
9 though resources generally must be built in discrete sizes. In reality, a partially
10 displaced capacity resource might still be the most cost-effective solution during the
11 deficiency period, despite contributions from other QF or RVOS resource
12 alternatives. To the extent an IRP resource addition is “lumpy” and “over-sized”
13 relative to the capacity requirement in the year it is added, the PDDRR methodology
14 provides capacity value from deferral of the entire IRP resource, rather than just the
15 need in that year. In that regard, capacity costs under the PDDRR methodology can
16 result in deferral of resources before the year of the need. However, this does not
17 result in payment for capacity costs before the year in which an IRP resource addition
18 is forecasted to occur as proposed by OSEIA.

19 **Q. Does the North Carolina decision allowing QFs to receive capacity payments**
20 **before a utility’s first resource addition provide support for OSEIA’s**
21 **arguments?**

22 A. No. OSEIA misplaces its reliance on the North Carolina Commission decision. The
23 North Carolina Utility Commission recently overturned its 2014 decision, eliminating

1 payments for capacity before the first resource addition.³⁹

2 **Q. Have contracts executed since the 2017 IRP was prepared reduced PacifiCorp's**
3 **generation capacity needs in 2029 relative to what was contemplated in the**
4 **preferred portfolio?**

5 A. Yes. Since the 2017 IRP was prepared, PacifiCorp has entered into long-term
6 contracts for resources totaling over 500 MW of nameplate capacity and over 150
7 MW of capacity contribution. The 2015 IRP continues to form the basis for the
8 capacity deficiency year in the currently approved standard QF values, and would be
9 subject to significantly larger changes since it reflects inputs from more than three
10 years ago.

11 **Q. What do you recommend for sufficiency period capacity value and timing?**

12 A. PacifiCorp agrees with the Commission that it is most efficient for the first version of
13 RVOS to use the deficiency year reflected in the currently approved standard QF
14 values, currently 2028 based on the 2015 IRP. Since sufficiency period prices are
15 already based on market, which is the marginal capacity resource in the IRP preferred
16 portfolio during that period, no additional capacity payments are appropriate.

17 ***CAPACITY CONTRIBUTION***

18 **Q. What issues do parties raise related to the generation capacity element?**

19 A. Staff proposes that the capacity contribution for RVOS should be equal to the value
20 for fixed solar resources identified in PacifiCorp's IRP.⁴⁰ OSEIA supports the

³⁹ *In the Matter of Biennial Determination of Avoided Cost Rates for Electric Utility Purchases from Qualifying Facilities – 2016*, Docket No. E-100, Sub 148, Order Establishing Standard Rates and Contract Terms for Qualifying Facilities (Oct 11, 2017) (<http://starw1.ncuc.net/NCUC/ViewFile.aspx?Id=9b202168-0968-4338-9c64-70b5366ab109>)

⁴⁰ Staff/200, Andrus/7.

1 Capacity Factor (CF) method “because it is a consistent, transparent approach that
2 can be readily applied to each of the utilities.”⁴¹ ODOE questions the significant
3 change in generation capacity value between the standard methodology under the
4 2015 IRP and the PDDRR methodology under 2017 IRP.⁴² ODOE also requests a
5 comparison of the capacity contributions of fixed tilt solar resources in western
6 Oregon and tracking solar resources in eastern Oregon.⁴³

7 **Q. What guidance did the Commission provide on this issue?**

8 A. The Commission indicated that the capacity value and deficiency date should be in
9 line with currently approved standard nonrenewable QF avoided cost capacity
10 value.⁴⁴ The Commission also stated that “during a resource deficient period, a utility
11 multiplies the contribution to peak of a QF’s resource type by the capacity cost of the
12 utility’s avoided proxy resource”⁴⁵ and provides an example of how capacity
13 contribution values can be drawn from values from an acknowledged IRP.

14 **Q. Did the Commission provide any guidance on how it will evaluate proposed**
15 **changes to the RVOS methodology?**

16 A. Yes. The Commission indicated it will balance accuracy, transparency, and
17 accessibility in reviewing alternative approaches.⁴⁶

18 **Q. Is PacifiCorp’s IRP based on an approved capacity contribution methodology?**

19 A. Yes. PacifiCorp’s 2015 and 2017 IRPs both use the CF method, consistent with
20 Order No. 16-236.

⁴¹ OSEIA/100, Beach/11.

⁴² ODOE/100, Delmar/5.

⁴³ ODOE/100, Delmar/5.

⁴⁴ See Order No. 17-357 at 6.

⁴⁵ See *id* at 7.

⁴⁶ See Order No. 17-357 at 6.

1 **Q. What are the key inputs to the CF method?**

2 A. The capacity contribution value under the CF method is a function of two inputs: (1)
3 the share of the annual loss of load probability (LOLP) in each hour; and (2) the
4 hourly capacity factor of the resource being evaluated. A resource's capacity
5 contribution is calculated by multiplying these two values for each hour of the study
6 period and summing the result.

7 **Q. Can the RVOS calculation produce the same result as the capacity contribution**
8 **study in the IRP?**

9 A. Yes. If the same generation profile from the IRP is used, the RVOS template will
10 produce the same capacity contribution value as that reported in the IRP. This is
11 because the RVOS template has been populated with the LOLP values from the IRP,
12 and the RVOS template designed by E3 automatically carries out the same calculation
13 performed for the IRP.

14 **Q. Have you compared the capacity contribution values under the CF method for**
15 **various solar generation profiles?**

16 A. Yes. The table below shows capacity factors and capacity contribution values for
17 various solar resources, including fixed and tracking solar resources in Oregon, as
18 represented in the 2017 IRP, the solar shape proposed by OSEIA, and the solar shape
19 contained in PacifiCorp's initial RVOS submission.

Table 2: Capacity contribution comparison

Solar Profile	Capacity Factor	Capacity Contribution (2015 IRP)	Capacity Contribution (2017 IRP)
OSEIA Fixed Solar	18.2%	23.7%	43.9%
PacifiCorp Initial RVOS Fixed Solar	20.8%	26.1%	46.5%
2017 IRP Oregon Fixed Solar	23.6%	29.9%	53.9%
2017 IRP Oregon Tracking Solar	26.6%	33.2%	64.8%

1 **Q. What does the table show?**

2 A. Table 2 demonstrates that capacity contribution values increase as the capacity factor
 3 of solar resources increases. Since the underlying profiles all reflect the position of
 4 the sun, the relationship is relatively linear. In contrast, capacity contribution values
 5 for wind resources in the IRP are lower, despite typically having a higher annual
 6 capacity factor than solar, due to timing differences. The values for capacity
 7 contribution of Oregon solar resources in the 2017 IRP match the values reported in
 8 the 2017 IRP. Capacity contribution values for fixed and tracking solar resources
 9 based on the 2015 IRP LOLP values vary slightly from values reported in the 2015
 10 IRP because the capacity factor of the solar resources used to calculate capacity
 11 contribution was slightly different in the 2015 IRP.

12 **Q. What is the effect of assuming a higher capacity contribution value for a
 13 resource with a lower capacity factor?**

14 A. The RVOS model automatically spreads avoided generation capacity costs across the
 15 generation profile of the modeled resource. If that generation profile has a smaller
 16 capacity factor but the same capacity contribution, capacity payments will necessarily
 17 be higher on a per MWh basis. This contradicts the premise of the CF method, which
 18 is that all generation delivered during periods with a risk of loss of load equally

1 support reliable system operations. Resources that deliver less generation should be
2 credited for capacity benefits consistent with their generation.

3 **Q. Are rooftop projects likely to have capacity factors that differ from the utility-**
4 **scale values in the IRP analysis?**

5 A. Yes. Existing PacifiCorp residential net-metering customers have capacity factors
6 that vary widely and range from under 10 percent to over 20 percent. The average
7 capacity factor is approximately 14.5 percent in eastern Oregon and southern Oregon,
8 and approximately 13 percent in the Willamette Valley. Residential solar capacity
9 factors are generally less optimal than utility-scale resources, which typically tilt or
10 track to optimize position with regard to the sun.

11 **Q. Are community solar projects likely to have capacity factors that differ from the**
12 **utility-scale values in the IRP analysis?**

13 A. It depends. Larger community solar projects are more likely to be optimized similar
14 to utility-scale projects, with ideal panel orientations, low risk of shading, higher DC
15 to AC ratios, and other factors. Smaller community solar projects are likely to be less
16 optimal if they are shaped to a site rather selecting a site primarily based on its solar
17 resources.

18 **Q. Is it appropriate to use the capacity contribution values from the 2017 IRP with**
19 **the deficiency period from the 2015 IRP?**

20 A. No. An IRP preferred portfolio reflects the least-cost, least-risk plan under specified
21 assumptions including resource costs and alternatives, resource need, generation
22 capacity contribution, and integration costs. Changes in capacity contribution impact
23 PacifiCorp's resource need insofar as those capacity contribution values are applied

1 to PacifiCorp's existing resource portfolio. In the current analysis, switching from
2 the solar capacity contribution values in the 2015 IRP to those in the 2017 IRP would
3 result in a significant increase in capacity from PacifiCorp's existing portfolio of solar
4 resources, which total approximately 1,000 MW. This would in turn reduce the
5 resource need and potentially delay the deficiency period relative to that reflected in
6 the 2015 IRP preferred portfolio.

7 ***STANDARD AND PDDRR CAPACITY COMPARISON***

8 **Q. ODOE notes the significant change in generation capacity value between the**
9 **standard methodology and the PDDRR methodology.⁴⁷ Please provide more**
10 **detail on this change.**

11 A. This change is primarily a result of the higher capacity contribution for solar
12 resources in the 2017 IRP, net of reductions due to a one year delay in the deficiency
13 period and lower capacity cost assumptions. Details are shown in the table below.

⁴⁷ ODOE/100, Delmar/5.

Table 3: Generation Capacity Value Comparison

Study	Generation Capacity Value (\$/MWh)	Delta (\$/MWh)
	Real	Real
Standard	\$8.65	
+2017 IRP LOLP	\$15.39	\$6.75
+2028 -> 2029 deficiency	\$14.04	(\$1.35)
+Updated Capacity Cost	\$12.72	(\$1.32)
PDDRR	\$12.72	

1

TRANSMISSION AND DISTRIBUTION CAPACITY

2 **Q. Does PacifiCorp support the changes to avoided transmission and distribution**
3 **capacity value proposed by parties?**

4 A. No. The specifics of PacifiCorp's position on avoided transmission and distribution
5 capacity values are addressed in the testimony of Mr. Putnam (PAC/400).

6 **Q. Have any inputs related to avoided transmission and distribution capacity**
7 **changed?**

8 A. No. However, the reported results vary slightly as a result of changes in line losses as
9 discussed below.

10

LINE LOSSES

11 **Q. Does PacifiCorp support the change to line losses proposed by OSEIA?**

12 A. No. However, PacifiCorp has recalculated avoided line losses on a marginal, rather
13 than average basis. The specifics of PacifiCorp's proposed modifications to the line
14 loss element are addressed in the testimony of Mr. Putnam (PAC/400).

15 **Q. What is the impact of the change to line losses?**

16 A. Updating PacifiCorp's standard RVOS workbook for the changes to line losses
17 described by Mr. Putnam impacts the line loss element as well as the generation

1 capacity and transmission and distribution capacity elements. On a real-levelized
2 basis, incorporating marginal line losses based on PacifiCorp's system data results in
3 a total increase of \$0.21/MWh.

4 **HEDGE VALUE**

5 **Q. What issues do parties raise related to the hedge value element?**

6 A. Staff supports the use of five percent of the energy price as the proxy hedge value.⁴⁸
7 OSEIA suggests that solar resources reduce the use of natural gas or other market
8 price spikes and proposes alternative hedging values from a 2015 Maine study.⁴⁹

9 **Q. Do you have additional concerns about the five percent hedge value beyond**
10 **those previously identified?**

11 A. Yes. The five percent hedge value comes from a 2011 study of the risk premium
12 embodied in forward electricity market prices in the Pacific Northwest. The RVOS
13 energy price during the sufficiency period already reflects forward electricity market
14 prices rather than spot prices or marginal resource dispatch cost, so an incremental
15 adjustment for hedge value during the sufficiency period results in a double count.
16 Likewise, the RVOS energy price during the deficiency period already reflects
17 forward gas market prices so an adjustment for hedge value in that time frame is also
18 inappropriate.

19 **Q. Do you have any concerns about OSEIA's proposal for hedge value?**

20 A. Yes. OSEIA's proposal bears no resemblance to PacifiCorp's actual resource
21 planning. First, PacifiCorp is not fueling its gas resources with a 25-year fixed price
22 gas supply, nor is it clear why gas resource costs are an appropriate measure for

⁴⁸ Staff/100, Andrus/44-46.

⁴⁹ OSEIA/100, Beach/30-34.

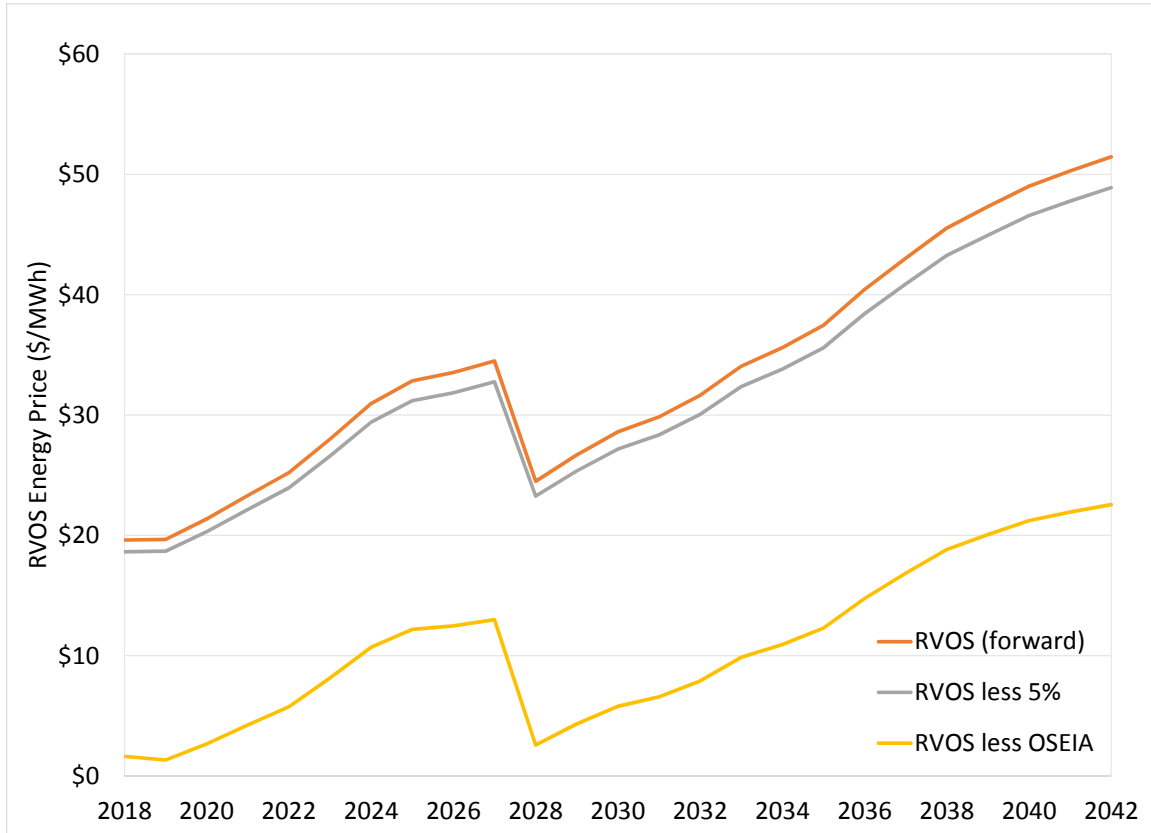
1 sufficiency period risk when energy values reflect electricity market prices. Second,
2 one of the primary benefits of a gas resource is the ability to adjust its dispatch in
3 response to changing requirements and economics. PacifiCorp's hedging horizon of
4 up to three years dramatically reduces risk without the appreciable costs identified by
5 OSEIA. Over a longer horizon, portfolio changes are an appropriate means of
6 managing risk—a significant and sustained increase in market prices would make a
7 variety of alternative resources more economic, but particularly renewables such as
8 solar. This would be true for all market participants, not just PacifiCorp. Finally,
9 OSEIA suggests that a fixed price gas resource would have the same hedging benefit
10 as an identical renewable resource with zero fuel costs.⁵⁰ However, solar resources
11 are not identical and have significantly more delivery risk than a gas resource. If gas
12 prices spike, gas resources can still be operated at a high cost. If it is cloudy or panels
13 are covered in snow, solar resources will under deliver and cannot be operated at any
14 cost.

15 **Q. How big is the implied risk premium calculated by OSEIA?**

16 A. Enormous. PacifiCorp's forward price curve is intended as a forecast of forward
17 prices, i.e. the cost of acquiring volumes for future delivery today. Figure 4 illustrates
18 the current RVOS energy price based on forward prices, and that price with the risk
19 premium removed—the five percent value ordered by the Commission and OSEIA's
20 alternative hedging value of \$18/MWh in 2018.

⁵⁰ OSEIA/100, Beach/33–34.

Figure 4: RVOS Energy Prices: Forward Versus Spot



1 **Q. What do you recommend for the hedging adjustment in the RVOS?**

2 A. I recommend that the Commission reduce this RVOS element to zero. While the
3 premise of a risk premium may be valid, its application to forward market prices,
4 which already have an embedded risk premium, is inappropriate.

5 **ENVIRONMENTAL COMPLIANCE**

6 **Q. What issues do parties raise related to the avoided environmental compliance**
7 **element?**

8 A. Staff questions the relevance of environmental compliance calculated based on the
9 Clean Power Plan requirements from the 2017 IRP, recommends using alternative
10 CO₂ prices from a sensitivity study in the 2017 IRP, indicates that these prices should

1 be applied based on the results of the PacifiCorp's PDDRR methodology.⁵¹ OSEIA
2 proposes that identical carbon compliance costs should be applied to all utilities, and
3 proposes using PGE's values.⁵² OSEIA also proposes that all avoided emissions be
4 calculated based on a natural gas fired resource with a 7,500 Btu per kWh heat rate.⁵³

5 **Q. Please clarify the two components of avoided environmental compliance costs.**

6 A. Avoided environmental compliance costs reflect the price of CO₂ emissions and the
7 quantity of avoided CO₂ emissions.

8 **Q. What is the impact of using the alternative CO₂ prices proposed by Staff and
9 OSEIA?**

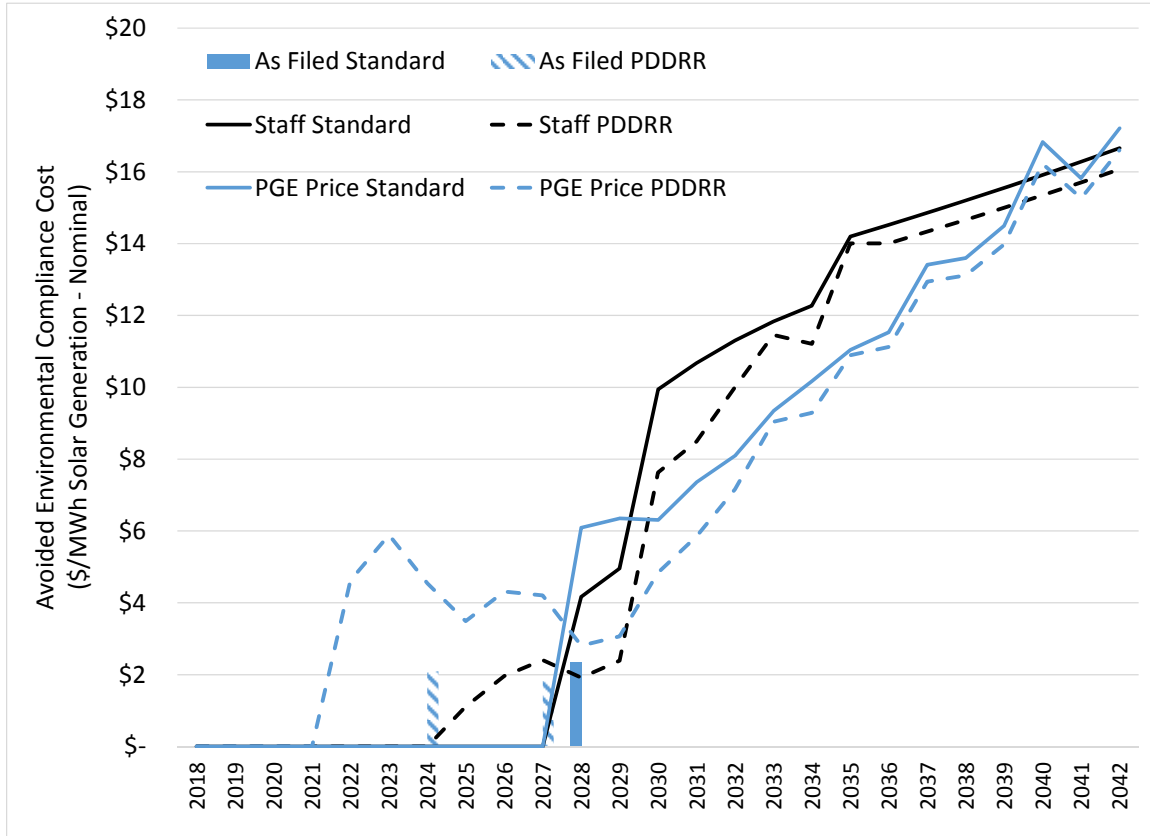
10 A. The results of the alternative CO₂ pricing proposals are shown in Figure 5. Because
11 incremental CO₂ reductions below Clean Power Plan cap levels are not required, they
12 did not result in avoided environmental compliance costs in PacifiCorp's original
13 analysis. In contrast, the CO₂ prices proposed by Staff result in avoided
14 environmental compliance costs for all CO₂ reductions starting in 2025. Similarly,
15 the CO₂ prices proposed by OSEIA (PGE's values) result in avoided environmental
16 compliance costs for all CO₂ reductions starting in 2022.

⁵¹ Staff/200, Andrus/15.

⁵² OSEIA/100, Beach/34.

⁵³ OSEIA/100, Beach/35.

Figure 5: Avoided Environmental Compliance Costs



1 **Q. Please explain the difference between the avoided environmental compliance**
 2 **costs based on PacifiCorp’s approved standard QF pricing inputs versus using**
 3 **the PDDRR methodology.**

4 A. As explained in my direct testimony, the avoided resource during the sufficiency
 5 period under standard QF pricing is market transactions, which have no assumed CO₂
 6 emissions. The avoided resource during the deficiency period under standard QF
 7 pricing is a proxy CCCT from PacifiCorp’s IRP, with a specified heat rate and
 8 emissions. As a result, under the standard QF pricing assumptions, avoided
 9 environmental compliance costs are zero through 2027, and then reflect the emissions
 10 rate of the proxy CCCT. Under the PDDRR methodology, the Generation and
 11 Regulation Initiative Decision Tools (GRID) model determines the avoided resources

1 for each hour of the study period, so emissions rates reflect a weighted average of
2 PacifiCorp's resources, including carbon-emitting coal and gas and market
3 transactions with no associated emissions. Under the PDDRR methodology,
4 emissions begin earlier, and reflect a varying emissions rate that approaches the
5 emissions rate of the proxy CCCT under the standard methodology. By the end of the
6 study period, the results under the standard and PDDRR methodologies and under
7 both proposed CO₂ price alternatives are similar.

8 **Q. Is it appropriate to use avoided environmental compliance costs from the**
9 **PDDRR methodology as proposed by Staff or based on the gas resource**
10 **proposed by OSEIA?**

11 A. No, neither approach is appropriate. Staff appears to suggest that avoided
12 environmental compliance costs under the PDDRR methodology should be combined
13 with values for other elements under the standard methodology. Avoided
14 environmental compliance costs should reflect assumptions that are consistent with
15 the avoided energy and generation capacity elements. As such, avoided
16 environmental compliance costs associated with dispatching PacifiCorp's thermal
17 resources are only appropriate if energy prices also reflect the marginal cost of those
18 resources, rather than the higher cost of market transactions. Similarly, it is unclear
19 why avoided environmental compliance costs should be based on a 7,500 Btu per
20 kWh heat rate gas plant when PacifiCorp's proxy gas plant under the standard
21 methodology has a heat rate of 6,530 Btu per kWh.

1 **Q. What do you recommend with regard to avoided environmental compliance**
2 **costs?**

3 A. For avoided environmental costs, the Commission directed utilities to calculate a
4 value for informational purposes and PacifiCorp has updated its RVOS model to
5 incorporate Staff's CO₂ pricing recommendation as this reflects a potential future
6 environmental compliance scenario that is drawn from the 2017 IRP and represents a
7 reasonable placeholder.

8 **RENEWABLE PORTFOLIO STANDARDS (RPS) COMPLIANCE**

9 **Q. What issues do parties raise regarding the avoided RPS compliance cost**
10 **element?**

11 A. Staff indicates that values from renewable portfolio compliance reports could be
12 applied to the reduction in RPS obligation from distributed solar generation.⁵⁴ RNW
13 indicates that is very important to assign a value to RPS compliance before an RVOS
14 estimate is applied to other programs.⁵⁵

15 **Q. Please clarify the two components of avoided RPS compliance costs.**

16 A. Avoided RPS compliance costs reflect the cost of RPS compliance and the impact of
17 a given application on PacifiCorp's RPS compliance position.

18 **Q. Will the impact of a program on PacifiCorp's RPS compliance position vary?**

19 A. Yes. The following two scenarios illustrate this point:

20 1. Renewable energy certificates (RECs) delivered to PacifiCorp for the benefit
21 of Oregon customers as a whole.

22 2. RECs delivered to PacifiCorp for the benefit of specified customers.

⁵⁴ Staff/100, Andrus/53.

⁵⁵ RNW/100, O'Brien/33.

1 Under example 1, each increment of solar output produces a REC which can
2 be used to meet PacifiCorp's RPS compliance obligation. If one MWh of solar
3 resource is provided to PacifiCorp, the quantity of RECs necessary for RPS
4 compliance is also reduced by one MWh.

5 Under example 2, each increment of solar output produces a REC that may be
6 retired on behalf of a specific customer. Depending on the program, the customer
7 load may be removed from PacifiCorp's RPS compliance obligation, i.e. PacifiCorp
8 would not need to procure additional RECs for a load that has already been allocated
9 100 percent renewable energy. The result is not a one-for-one reduction in RPS
10 compliance obligation, but rather a reduction based on the RPS percentage in that
11 year. For instance, PacifiCorp's RPS obligation is 35 percent in 2030. If one MWh
12 of solar resource is allocated to a specified customer in 2030, removing that one
13 MWh of customer load from PacifiCorp's RPS obligation would reduce the quantity
14 of RECs necessary for compliance by 0.35 MWh.

15 **Q. Is there an inter-temporal component to RPS obligations?**

16 A. Yes. Compliance with the Oregon RPS can be achieved with RECs generated in
17 previous years, but this "banking" is subject to certain limits. In combination with the
18 resources in the 2017 IRP preferred portfolio, PacifiCorp's existing REC bank is
19 expected to be sufficient to meet its Oregon RPS compliance obligations until 2035.
20 As a result, incremental costs for RPS compliance are unnecessary until 2035. While
21 some RECs are restricted to a five year banking limit, a significant reduction in load
22 or increase in REC supply over the near-term would be necessary before this impacts
23 RPS compliance costs.

1 **Q. Do the required renewable portfolio standard implementation plans (RPIP)**
2 **reasonably represent PacifiCorp's avoided RPS compliance costs?**

3 A. No. The incremental cost methodology compares the levelized cost of a qualifying
4 resource acquired based on conditions at the time it was acquired to the cost of a
5 combined cycle plant based on a current forecast of natural gas prices. As a result,
6 the methodology results in an incremental cost for resources that were acquired in the
7 past during periods of high natural gas prices, even though they were the least-cost,
8 least-risk options relative to non-renewable resources at the time they were acquired.

9 **Q. Does the RPIP provide useful information in the context of avoided RPS**
10 **compliance costs in RVOS?**

11 A. Yes. For example, from 2020 to 2021, PacifiCorp's incremental cost estimates drop
12 significantly and become negative.⁵⁶ This is a result of the addition of the 2021 wind
13 resources from the 2017 IRP preferred portfolio, as the incremental cost associated
14 with these resources is negative. Issues with the incremental cost methodology aside,
15 the 2017 IRP preferred portfolio includes the 2021 wind resources because they are
16 least-cost, least-risk before consideration of any additional RPS compliance benefits.
17 This indicates that these resources are lower cost than other alternatives, which is
18 consistent with the negative incremental cost result.

19 **Q. What do you recommend for avoided RPS compliance costs in the RVOS?**

20 A. To the extent renewable resources are cost-effective before considering RPS
21 compliance benefits, avoided RPS compliance costs should be zero. Given the

⁵⁶ See *In the Matter of PacifiCorp, dba Pacific Power, 2019-2023 Renewable Portfolio Standard Implementation Plan*, Docket No. UM 1914 (Dec. 28, 2017).

1 presence of several types of renewable resources in the 2017 IRP preferred portfolio,
2 this is a reasonable outcome. Given that long-term RPS compliance remains on open
3 issue, including avoided RPS compliance cost in RVOS continues to be premature.

4 **GRID SERVICES**

5 **Q. What issues do parties raise related to the grid services element?**

6 A. OSEIA suggests that storage paired with solar “has the potential to provide many grid
7 services (such as voltage support, regulation, and load following) as well as to
8 enhance the resiliency of electric service.”⁵⁷ ODOE highlights advanced technologies
9 such as smart inverters and storage systems that would impact the value of distributed
10 solar resources.⁵⁸

11 **Q. Is it appropriate to consider grid service benefits related to RVOS applications**
12 **at this time?**

13 A. No. PacifiCorp recently filed a methodology for evaluating energy storage resources
14 in docket UM 1857 that may cover many of the grid services identified by parties.
15 While energy storage resources can provide significant value, much of that value is
16 dependent on the ability of system operators to track and control distributed resource
17 output. PacifiCorp does not currently have programs and systems that would provide
18 those elements, but recognizes that significant potential may exist. Because the
19 greatest benefits are associated with generation capacity needs that PacifiCorp may
20 not have until 2029 or later and evaluation techniques are still under active

⁵⁷ OSEIA/100, Beach/43.

⁵⁸ ODOE/100, DelMar/4.

1 consideration, it is appropriate to leave consideration of the combined benefits of
2 solar and energy storage to a later date.

3
4

UTILITY-SCALE ALTERNATIVE

5 **Q. What issues do parties raise related to RVOS values based on a utility-scale
6 alternative?**

7 A. Staff suggests that analysis of the costs of a utility scale solar proxy would provide a
8 helpful reference point for RVOS, and provides several points of clarification about
9 the assumptions it believes would be appropriate in that analysis.⁵⁹ OSEIA describes
10 several additional benefits that it believes should distinguish distributed solar from
11 utility-scale solar, beyond avoided T&D capacity, line losses and administrative
12 costs.⁶⁰

13 **Q. What utility-scale alternative did PacifiCorp provide in its direct filing?**

14 A. As discussed in my direct testimony, PacifiCorp provided a calculation using the
15 current PDDRR methodology approved for calculating avoided cost prices for
16 qualifying facilities in Oregon of up to 80 MW.

17 **Q. Has PacifiCorp prepared a utility-scale alternative using a solar proxy?**

18 A. Yes. PacifiCorp's 2017 IRP Update is expected to be filed in early May 2018, and
19 contains an up-to-date estimate of the cost of utility-scale solar resources Oregon. In
20 the 2017 IRP Update, the cost of a utility-scale tracking solar resource in Oregon is
21 \$36.06/MWh (2017\$), excluding solar integration cost. When this solar resource cost
22 is used in the RVOS model with an assumed start date of 2021, and adjustments for

⁵⁹ Staff/100, Andrus/57–58.

⁶⁰ OSEIA/100, Beach/40–41.

1 the T&D capacity, line loss, and administration elements only, the real-levelized
2 RVOS value is \$34.22/MWh, or approximately three percent higher than the results
3 based on the standard QF methodology. With an assumed start date of 2030, the real-
4 levelized RVOS value is \$30.39/MWh, or approximately nine percent lower than the
5 results based on the standard QF methodology.

6 **Q. What additional benefits does OSEIA ascribe to distributed solar resources**
7 **relative to utility solar resources?**

8 A. OSEIA states that, relative to utility-scale solar resources, distributed solar can have
9 reduced land use impacts, can allow for more customer choice, and can enhance the
10 reliability and resiliency of electric service when paired with on-site storage.⁶¹

11 **Q. Is it reasonable for the RVOS model to include these additional benefits?**

12 A. No. The additional benefits described by OSEIA flow to participating customers (or
13 potentially non-customers in the case of land use impacts) whereas the RVOS model
14 is intended to prevent cost-shifting between participating customers and non-
15 participating customers. Because these characteristics of distributed solar do not
16 reduce utility costs, non-participating customers do not benefit, and accounting for
17 them in the RVOS model is inappropriate. If anything, the value individual
18 participating customers ascribe to enhanced reliability, resiliency, and choice of
19 supply would serve to reduce the bill credit rates necessary to encourage customers to
20 adopt net metering or community solar programs.

⁶¹ OSEIA/100, Beach/40-41.

1 **CONCLUSION**

2 **Q. Please summarize the recommendations in your reply testimony.**

3 A. With the changes described herein, PacifiCorp's RVOS workbook based on approved
4 standard QF pricing incorporates improvements identified by parties and is consistent
5 with the direction provided by the Commission in Order No. 17-357. As such, it is
6 ready to be populated with inputs and assumptions for specific applications, including
7 details related to generation profile, interconnection voltage, transmission and
8 distribution location, and contract term. I would recommend that in consideration of
9 any application, the results of the RVOS workbook continue to be considered in light
10 of the PDDRR and utility-scale RVOS results and other areas of uncertainty.

11 **Q. Does this conclude your reply testimony?**

12 A. Yes.