

1 for the RVOS calculation as the utility uses to determine standard avoided cost prices.
2 However, there is a dispute as to whether utilities should always use the same vintage of
3 forward price curve as is used for the currently effective standard avoided cost prices.
4 This is what PacifiCorp recommends. Staff recommends that the utilities should use the
5 most recently available forward price curves.

6 Staff does not think it is necessary to rely on the same vintage of forward price
7 curve used by the most current standard avoided cost prices approved by the Commission.
8 Notably, the forward price curve is not inextricably linked to other IRP inputs. For
9 example, when PacifiCorp made its post-IRP-acknowledgment avoided cost filing in
10 April 2018, PacifiCorp used March 2018 forward price curves for its energy prices rather
11 than the forward price curves used in its IRP.¹ Staff believes it is appropriate to
12 incorporate the most recently available prices into the RVOS calculation rather than using
13 more stale prices.

14 **2. 12 x 24 shape.**

15 The forward price curves used by the utilities are forecasts of energy prices in
16 monthly on- and off-peak blocks. The Commission ordered utilities to shape these
17 monthly blocks into 12 x 24 blocks (one 24-hour shape for each month) to account for
18 varying prices in different hours.² To do this, each utility identified a source for hourly
19 prices. The hourly prices from that source are not used to value the energy directly, but
20 to create a set of hourly shaping factors that are then applied to the utility's monthly price
21 forecast. The hourly prices for each month, when averaged, are equal to the utility's
22 monthly price forecast, just as the average of the shaping factors is one.

23 There is little consensus in these dockets about the appropriate source of the
24 hourly prices or the method to create the price shapes. Each of the utilities used a

25 ¹ See PacifiCorp's UM 1729—Standard Avoided Cost Purchases from Eligible Qualifying
26 Facilities—Compliance Filing, Table 2 (April 26, 2018).

² *In the Matter of Public Utility Commission of Oregon Investigation to Determine the Resource Value of Solar* (UM 1716), Order No. 17-357, p. 4.

1 different source for the hourly prices and a different method. Staff believes PGE's
2 method is most consistent with the Commission's directions in Order 17-357 and
3 recommends that the other two utilities use a similar method.

4 PGE created daily shape factor profiles for each month using hourly prices for
5 2024 produced by its system dispatch model, AURORA. PGE then applied the shape
6 factors to the weighted average annual price (based on monthly prices) for each year to
7 create daily price profiles for each month of the year. Staff believes the hourly prices
8 produced by PGE's own system dispatch model, based on the prices in markets in which
9 PGE operates, are appropriate representations of the prices that would be available were
10 PGE to purchase solar generation.

11 PacifiCorp created the price shape using 15-minute Energy Imbalance Market
12 (EIM) market prices for the 12 months ending September 2017. In its testimony, Staff
13 noted its concern regarding PacifiCorp's reliance on the EIM for the price shape because
14 most of PacifiCorp's transactions are not in that market, so the EIM shape may not
15 accurately represent the value of solar to its system.

16 Idaho Power used two different shaping methodologies. Its first methodology
17 uses data collected from Idaho Power's participants in the Oregon PV Pilot, Oregon
18 Schedule 88. Its second methodology uses actual hourly Mid-Columbia ("Mid-C")
19 market prices for 2017. Idaho Power's first method does not comply with Order No. 17-
20 357 because it does not actually produce a 12 x 24 shape.³ Idaho Power Company's
21 second methodology appears flawed because the shaping factors do not average to one as
22 they should.

23 Staff recommends that both PacifiCorp and Idaho Power use their system dispatch
24 models as PGE has done to create a 12 x 24 shape for application to the energy price. As
25 Staff noted in its testimony, PacifiCorp could still incorporate data from the EIM if
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³ UM 1911 Staff/200, Andrus/ 3-4.

1 PacifiCorp wished. But, including information from the utilities' system dispatch models
2 would create 12 x 24 shapes more consistent with prices applicable to the value of energy
3 generated in the utilities' territories.

4 Notably, it is not clear that EIM prices will provide a shape that is appropriate for
5 PacifiCorp. PacifiCorp and OSEIA disagree on whether hourly prices that PacifiCorp
6 considers to be outliers should be excluded. PacifiCorp asserts they should be excluded
7 while OSEIA includes them. Given that PacifiCorp uses only one year of data from the
8 EIM, it is difficult to know whether the prices are truly outliers. This ambiguity supports
9 use of the utilities' system dispatch models

10 In any event, if the EIM method is allowed, it is appropriate to weight the average
11 price in each hour by quantity of production as PacifiCorp recommends.⁴

12 **B. Generation capacity.**

13 **1. Resource deficiency period.**

14 Under Order No. 17-357, the utilities are required to “determine the capacity
15 value consistent with the Commission’s standard nonrenewable QF avoided cost
16 guidelines.”⁵ When the utility is resource sufficient, the value is based on the market
17 energy price. When the utility is resource deficient, the value is based on the contribution
18 to peak of solar PV, multiplied by the capacity cost of a combined cycle combustion
19 turbine.⁶ A utility is considered to be resource deficient under the standard QF avoided
20 cost guidelines starting the year in which the utility’s IRP shows acquisition of a “major
21 resource” (one that is at least 100 MW and has a duration greater than five years).⁷

22 ⁴ See UM 1910 PacifiCorp’s Opening Brief 8. Staff note: The weighting methodology that
23 PacifiCorp suggests requires sub-hourly data. Accordingly, it could not be used if the source of
hourly prices does not provide sub-hourly data.

24 ⁵ Order No. 17-357, supra, p. 21.

25 ⁶ *In the Matter of Staff’s Investigation Relating to Electric Utility Purchases from Qualifying
Facilities* (UM 1189), Order No. 05-584, p. 26.

26 ⁷ *In the Matter of the Public Utility Commission of Oregon Investigation into Determination of
Resource Sufficiency, Pursuant to Order No. 06-538* (UM 1396), Order No. 10-488, p. 3 (noting
major resource for purposes of determining resource deficiency is same as major resource for
purposes of competitive bidding guidelines); *In the Matter of Public Utility Commission of*

1 In Order No. 17-357, the Commission asked Staff to convene a workshop at a
2 future time to explore options for valuing capacity additions incrementally during a
3 utility's resource sufficiency period. The Commission stated that the issues to be
4 explored at the workshop include: "(1) allowing the full capacity value up to a reasonable
5 number of years before the deficiency year (e.g., three or four years) as recognition that it
6 takes several years to ramp up infrastructure to avoid a major resource; (2) using the
7 short run marginal cost of fixed operations and maintenance (O&M) as a proxy value as
8 suggested by E3; and (3) other ideas arising from Commission dockets or those raised by
9 the parties."⁸

10 The Oregon Solar Energy Industries Association (OSEIA) recommends that the
11 Commission immediately adopt the first proposal and move up the resource deficiency
12 date by three years for PGE and four years for PacifiCorp and Idaho Power. Staff
13 opposed OSEIA's recommendation recommending the Commission allow Staff to
14 explore this option at the workshop ordered by the Commission prior to any decision to
15 implement it.⁹

16 **2. Contribution to peak (CTP) factor.**

17 In Order No. 17-357, the Commission contemplated that the CTP used in the
18 determination of generation capacity value would be the CTP of the utility's proxy solar
19 resource in the IRP. During a resource deficient period, a utility multiplies the
20 contribution to peak of a QFs resource type by the capacity cost of the utility's avoided
21 proxy resource. For example, if the utility's acknowledged IRP states that solar PV has a
22 25 percent contribution to peak, the capacity value would be 25 percent of the capacity
23 cost of the avoided proxy resource.¹⁰

24 *Oregon Investigation Regarding Competitive Bidding* (UM 1182(1)), Order No. 12-007
25 ("Major resources are resources with durations later than 5 years and quantities greater than 100
26 MW.").

⁸ Order No. 17-357, *supra*, p. 7.

⁹ UM 1910-12 Staff/300, Andrus/8.

¹⁰ Order No. 17-357, *supra*, p. 7.

1 PacifiCorp's proposed method differs from the method outlined by the
2 Commission in Order No. 17-357. PacifiCorp proposes to determine the contribution to
3 peak value for a given solar resource based on the 12 x 24 loss of load probability
4 (LOLP) in each hour. Staff acknowledges that the additional granularity proposed by
5 PacifiCorp may be appropriate in future iterations of the RVOS Methodology. However,
6 Staff believes that at this point, it is preferable that all the utilities use the method to
7 determine the value for generation capacity as outlined in Order No. 17-357.

8 The methodology at issue in Phase II is a methodology to "produce a 25-year
9 marginal levelized value for a generic, small-scale solar resource installed[.]"¹¹ The
10 granularity PacifiCorp seeks is generally obtained using one of the four CTP values
11 included in its IRP. More specifically, PacifiCorp's last two IRPs have included four
12 solar CTP values, two for a resource oriented to the East, but one fixed the other tracking,
13 and two CTP values for a resource oriented to the West, one fixed and one tracking. The
14 Commission's method would allow PacifiCorp to include a CTP that is most consistent
15 with the type of resource that may be subject to the RVOS.

16 **C. T&D Capacity.**

17 Staff recommends that the Commission order PacifiCorp and Idaho Power to use
18 either a marginal cost of service (MCOS) study or the National Economic Research
19 Associates (NERA) method described by OSEIA to determine the value for distribution
20 capacity.

21 **1. Distribution.**

22 The methods used by Idaho Power and PacifiCorp to obtain a more location-
23 specific distribution value are not sufficiently vetted and supported. In Docket No. UM
24 1716, Mr. Olson's testimony reflects that the location-specific information needed to
25 make a more location-specific determination of the T&D capacity value is more than
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¹¹ Order No. 17-357, *supra*, p. 1.

1 simply identifying specific substation upgrades that the utility thinks are deferrable. Mr.
2 Olson described the location-specific information that he thinks is necessary as follows:

3 Advances in technology, such as internet connected smart meters, are
4 making the collection and analysis of locational specific data possible
5 where historically it hasn't been. Several states have tackled this new
6 opportunity, notably California through its Distribution Resource Plan
7 proceeding. California utilities are currently developing plans to "more
8 fully integrate [distributed energy resources] into system planning,
9 operations, and investment." As part of these plans, utilities will be
10 required to demonstrate the capacity to integrate distributed resources
11 into their systems, the locational benefits that different resources can
12 offer, and actionable pilot programs and tariffs to incentivize and capture
13 this value. These distribution-level resource plans are expected to provide
14 valuable information about where distributed energy resources can be
15 targeted to achieve the highest value. In the absence of location-specific
16 distribution system planning data, more general data can be gathered
17 from utility capital budgets. Depending on the use of the RVOS, these
18 more general values may be sufficient to provide high-level estimates of
19 avoidable utility transmission and distribution expenditures.¹²

20 Mr. Olson described how the information described above could be used in the
21 calculation of RVOS.

22 **Q. How can time- and area-specific marginal costing be used in
23 estimating the Oregon RVOS?**

24 A. The RVOS Model that I describe * * * has the capability to
25 incorporate hourly avoided costs at a given location on the system.
26 Hourly avoided costs are estimated for a variety of categories such as
energy, capacity, distribution deferral value, and others. The RVOS
Model can be run multiple times with different assumptions to generate
different values for different locations. However, in order for accurate
time- and area-specific marginal costing to be incorporated into the
RVOS, the utilities must collect and provide data on the location-
specific benefits described above. In particular, Oregon IOUs may
benefit from studying how the value of solar and other distributed
energy resources differ between geographic locations based on the
specific transmission and distribution system characteristics in that area.
Because this level of granularity is not available at this time, my
testimony focuses on the methodology for developing an RVOS and
provides a sample value for solar at a generic location.¹³

27 PacifiCorp's and Idaho Power's attempts to obtain a more location-specific value by
28 selecting a handful of substation upgrades that they identify as load-growth related and

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30 ¹² UM 1716 Staff/200, Olson/12.

¹³ UM 1716 Staff/200, Olson/12-13.

1 located where they believe additional solar resources could potentially impact the need
2 for the upgrade is not the sophisticated analysis of time-and-area marginal costing that E3
3 seemed to contemplate.

4 Staff acknowledges the utilities' concern that using a MCOS could capture the
5 value of new assets or upgrades that are not load-growth driven. However, PGE
6 addressed this issue by narrowing the type of resources included in the calculation.¹⁴
7 And, as OSEIA notes in its testimony, even upgrades that are reliability-driven can
8 provide additional capacity benefits, which are appropriate included in the RVOS
9 calculation. Finally, the Commission stated that the T&D capacity value need not be
10 limited to load-growth related investments.¹⁵

11 2. Transmission.

12 Staff also recommends that the Commission order PacifiCorp and Idaho Power to
13 use the method used by PGE to determine the value for transmission capacity. PGE's
14 avoided transmission value is based on the distributed solar generator's ability to allow
15 PGE to defer the cost of firm transmission service, and the price is based on BPA's 2018
16 tariffed Firm Point-to-Point transmission service with Scheduling, System Control, and
17 Dispatch Service.

18 PacifiCorp included zero value for deferred transmission in its RVOS calculation,
19 asserting that solar generation is not a viable alternative to transmission upgrades.¹⁶
20 Idaho Power used the same method for both distribution and transmission.¹⁷ As already
21 noted, Staff does not think Idaho Power's method is sufficient.

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24 ¹⁴ See UM 1712 PGE/400, Murtaugh/7 (“The value for an avoided distribution asset was
25 estimated to be the cost of the sub-transmission costs plus substation costs, in dollars per kW-
26 year.”).

¹⁵ Order No. 17-357, *supra*, p. 9.

¹⁶ UM 1910 PAC/200, Putnam/3-4.

¹⁷ UM 1911 Idaho Power/100, Haener/8-9

1 **D. Administrative costs.**

2 This component is intended to capture costs that are both incremental to what the
3 utility incurs for any other specific type of customer account and incremental to any
4 portion of this cost that is paid by the interconnecting solar generator.¹⁸ In addition, the
5 cost must be incremental to costs allocated to ratepayers other than the solar generators.
6 Once a utility program is implemented based on prices determined with the RVOS
7 Methodology, those costs become part of the cost-benefit analysis specific to that
8 program and not a generic RVOS cost, per se.¹⁹

9 PacifiCorp and PGE appear to have determined a reasonable methodology for
10 identifying these incremental costs. Idaho Power has not. Idaho Power includes
11 administrative costs that are passed along to all ratepayers eligible for the solar PV
12 program through an automatic adjustment mechanism.²⁰ Accordingly, these costs are not
13 incremental costs of the type that should be included in the RVOS calculation. Staff
14 recommends that the Commission order Idaho Power to use a methodology that estimates
15 only the incremental administrative costs described above.

16 **E. Market price response.**

17 **1. Methodology.**

18 The value for market price response (MPR) is the “estimated impact on [market]
19 price under a specified solar penetration (\$/MWh) multiplied by utility net market
20 purchases or sales (MWh). This total \$ amount is then allocated to all solar generation
21 (MWh) to yield a final \$/MWh avoided cost value which is allocated equally to all
22 hours.”²¹ The equation is as follows:

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25 ¹⁸ UM 1716 Staff/401, Olson/11, Staff Response to TASC Data Request 10.

26 ¹⁹ Staff/100, Andrus, 36-37.

²⁰ See ORS 757.635(10).

²¹ UM 1716 Staff/200, Olson/33.

1 decline. This is inappropriate, as the value from the MPR element is directly tied to a
2 utility's long or short market position and the markets in which it transacts.

3 **F. Environmental compliance.**

4 In Order No. 17-357, the Commission concluded the value for environmental
5 compliance would be zero at this time, but ordered the utilities to calculate a value for
6 informational purposes:

7 We direct the utilities to calculate a value for informational purposes, to
8 be used as a placeholder in their initial RVOS filings. The utilities should
9 estimate the avoided cost based on a reduction in carbon emissions from
10 the marginal generating unit with the carbon regulation assumptions from
their IRP. We will decide on the application of this element based on
implementation of RVOS at a later time.²⁵

11 Staff is not satisfied with Idaho Power's and PacifiCorp's informational estimate
12 of environmental compliance costs. However, the shortcomings of their estimates may
13 stem from limited analysis of carbon compliance costs in their most recent IRPs.

14 Staff anticipated that even if a utility did not assume any regulatory compliance
15 costs in its base planning case, it could use the sensitivity analysis required by Guideline
16 8 to provide an informational estimate of potential carbon compliance costs that may be
17 avoided with the purchase of solar generation. Commission IRP Guideline No. 8
18 provides.

19 Utilities should include, in their base-case analyses, the regulatory
20 compliance costs they expect for carbon dioxide (CO₂), nitrogen
21 oxides, sulfur oxides, and mercury emissions. Utilities should analyze
22 the range of potential CO₂ regulatory costs in Order No. 93-695,
from zero to \$40 (1990\$). In addition, utilities should perform
sensitivity analysis on a range of reasonably possible cost adders for
nitrogen oxides, sulfur oxides, and mercury, if applicable.²⁶

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26 ²⁵ Order No. 17-357, *supra*, p. 13.

²⁶ *In the Matter of Public Utility Commission of Oregon Investigation into Integrated Resource Planning* (UM 1056), Order No. 07-047, App. A, p. 6 (IRP Guideline 8).

1 **G. RPS Compliance**

2 The Commission has not yet defined the element of Renewable Portfolio Standard
3 (RPS) compliance. The parties that discuss this element agree that it could measure the
4 value solar has in reducing load and therefore, the utility's compliance obligation. Staff
5 recommends that the Commission allow Staff to explore a methodology for determining
6 this value with stakeholders.

7 **H. Hedge value.**

8 Staff recommends that the Commission retain the current method of using five
9 percent of the energy value for the hedging value. Staff recommends that the
10 Commission reject OSEIA's proposal that all utilities substitute a different hedge value
11 because the proposal is inconsistent with the RVOS Methodology adopted by the
12 Commission.

13 The hedge value included in the RVOS Methodology is the cost of hedging the
14 utility avoids by procuring energy from a solar resource. The costs associated with
15 generation from thermal sources can vary widely whereas the price of solar generation is
16 relatively constant. To the extent that a utility acquires a solar resource as part of its
17 generation portfolio it is avoiding the need to acquire generation from another source
18 (i.e., a natural gas-fired plant or a market purchase). Accordingly, the solar generation
19 decreases the amount generation cost the utility must hedge and therefore, reduces the
20 utilities' hedging costs.²⁷

21 For purposes of valuing avoided hedging, E3 proposed that utilities use five
22 percent of the value for energy based on a "peer-reviewed paper "How Big Is the Risk
23 Premium in an Electricity Forward Price? Evidence from the Pacific Northwest."²⁸

24 The value proposed by OSEIA however, is not limited to an estimate of the cost
25 of hedging that the utilities avoid by having solar generation. OSEIA also includes an

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²⁷UM 1716 Staff/401, Olson/23-24 (Staff Response to TASC DR No. 20).

²⁸UM 1716 Staff/401, Olson/23-24 (Staff Response to TASC DR No. 20).

1 estimate for the value of solar as a hedge against market price volatility. E3 rejected the
2 idea that this value should be included in the RVOS calculation for rooftop solar because
3 this hedge value does not accrue to the ratepayer, but to the owner of the solar generation:

4 [T]to the extent that a utility acquires a solar resource as part of its
5 generation portfolio, that resource allows the utility to avoid market
6 purchases of electricity and/or natural gas and any associated hedging costs.
7 However, for behind-the-meter generation, this value accrues to the owner
8 of the solar installation, not to non-participating utility ratepayers. Solar
9 owners acquire the resource for the purpose of offsetting all or a portion of
their onsite consumption, thereby replacing their potentially variable
electricity bill with a more stable cost stream based on the cost of solar
ownership. The solar installation thereby provides a hedge value for the
solar owner.²⁹

10 The remaining load does not experience a reduction in volatility as a result
11 of the solar installation. Behind-the-meter solar does not become part of the
12 utility's resource portfolio. Rather, behind-the-meter solar functions like
13 direct access, in which the load is separated from the remaining bundled
14 customers and served with a third-party resource, i.e., a resource that is
15 outside the utility's portfolio. Since the utility does not own or contract
16 directly with the solar PV resource, the utility therefore will need to
17 continue to hedge any market transactions for the remaining load in the
18 same proportion as if the solar installation had not occurred. As a result, the
19 hedge value accrues to the system owner, and the remaining utility
20 ratepayers do not experience a reduction in bill volatility.³⁰

21 Because the Commission adopted an RVOS Methodology that excludes values
22 that accrue to the generation owner rather than ratepayers in general, OSEIA's proposal
23 to include a hedging value related to reduced price volatility for this iteration of the
24 RVOS Methodology should be rejected. However, Staff will explore whether it is
25 appropriate to include both the hedge value and avoided hedge value in the RVOS
26 calculation when the solar generation at issue is not behind-the-meter.

27 **I. Updates to RVOS.**

28 Staff recommends annual updates and identifies at least two options for annual
29 updates. Under the first option, the updates could be tied to updates to avoided cost
30 prices. Meaning, the utilities could be required to file updated RVOS values within a

29 Attachment, UM 1716 Staff/401, Olson/ (Staff Response to TASC DR No. 20).

30 Attachment, UM 1716 Staff/401, Olson/ (Staff Response to TASC DR No. 20).

1 certain interval after acknowledgment of a utility's IRP and on May 1 of each year. The
2 drawback of this approach is the additional workload on utilities, Staff, and stakeholders
3 already working to develop avoided cost prices on a relatively compressed time period.
4 Also, tying the RVOS Updates to IRP acknowledgment lessens the predictability of the
5 timing of some of the updates.

6 The second option is to require the utilities to only file annual updates on a
7 designated date. Under this option, the utilities would still incorporate information from
8 their most recently acknowledged IRPs and acknowledged IRP Updates, but the
9 acknowledgments would possibly have been several months prior. The drawback of this
10 option is that the information could be more stale than in the first option. The benefit of
11 this option is that it would provide stakeholders in the solar development community
12 more predictability regarding the timing of RVOS price updates.

13 **J. Utility scale alternative.**

14 Staff believes there are too many issues related to the utility-proposed alternate
15 utility-scale methods of valuing RVOS to seriously consider implementing these methods
16 at this time.³¹

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³¹ See Opening Brief of Renewable Northwest, pp. 9-10; OSEIA/100, OSEIA/100, Beach/40-42.

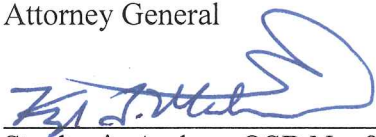
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K. Conclusion.

Staff's opening brief includes a summary of recommendations from Staff testimony filed in this docket. These recommendations remain unchanged.

DATED this 9th day of August 2018.

Respectfully submitted,
ELLEN F. ROSENBLUM
Attorney General


Stephanie Andrus, OSB No. 925123
Sr. Assistant Attorney General
Of Attorneys for Public Utility
Commission of Oregon